Impacts Analysis of Amendments to Mexico's Unit Commitment and Dispatch Rules

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1 National Renewable Energy Laboratory
2 encoord

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List of Acronyms and Abbreviations

CENACE	Centro Nacional de Control de Energía
CFE	Comisión Federal de Electricidad
CLSB	Contrato Legado para Suministro Básico
CRE	Comisión Reguladora de Energía
IMTA	Instituto Mexicano de Tecnología del Agua
LIE	Ley de la Industria Eléctrica
NSRDB	National Solar Radiation Database
PEMEX	Petróleos Mexicanos
PIE	Productores Independientes de Energía
PRODESEN	El Programa para el Desarrollo del Sistema Eléctrico Nacional
SENER	Secretaría de Energía
SLP	Subasta de Largo Plazo
WIND	Wind Integration National Dataset

Executive Summary

This report is provided as part of the 21st Century Power Partnership program in Mexico. The overall goal of this program is to support Mexico's power system transformation by accelerating the transition to a reliable, financially robust, and low-carbon system. 21st Century Power Partnership Mexico activities focus on achieving positive outcomes for all participants, especially by addressing critical questions and challenges facing policymakers, regulators, and system operators.

The report quantifies the potential impacts on Mexico's power system, of amendments both published and under discussion to Mexico's electricity legal framework and to market rules that would modify the way electricity generators are committed and dispatched.

For the analysis, we use a production cost model of the Mexican power system implemented in encoord's commercial Scenario Analysis Interface for Energy Systems (SAInt) software [1]. The data and information required to develop the model are based on publicly available data sources. The model data, assumptions, scenarios, and results were examined and approved by several Mexican subject matter experts with experience in energy planning and operation of the Mexican power system and wholesale market and in power generation.

The hourly optimal electricity dispatch of the Mexican electricity system is modeled for 1 year under four scenarios, a reference scenario, and three alternative scenarios meant to evaluate the potential impacts of increasing participation of the state-owned power plants in generation mix, electricity production costs, emissions, and renewable curtailment. The three alternative scenarios represent different levels of priority of generation from state-owned power plants (excluding diesel-fueled and open-cycle gas turbine generators). Figure E-1 shows the summary results of the Reference Scenario and the comparison to the three analyzed scenarios.

- **Reference**: Power plant dispatch is based on the standard unit commitment and economic dispatch approach. This scenario represents current practices in Mexico and was validated against actual results.
- **Scenario 1 – Comisión Federal de Electricidad (CFE) Priority**. CFE's power plants are secured at their minimum level of production, their remaining generation capacity is subject to economic dispatch.
- **Scenario 2 – CFE + PIE Priority**. Both CFE power plants and private generators holding independent energy producer contracts *"Productores Independientes de Energía"* (PIE) with CFE, are secured at their minimum levels of production, and their remaining generation capacity is subject to economic dispatch.
- **Scenario 3 – CFE Maximized**. CFE's power plants production is maximized. Private generators with PIE contracts are given lower priority than CFE plants, but higher priority over private generators that do not hold PIE contracts.

The study concludes that prioritizing generation from state-owned power plants under the above scenarios would lead to the following impacts on the Mexican power system, as summarized below:

- Electricity production costs would increase, over the Reference Scenario by 31.7% or $3,322M (Scenario 1), 31.2% or $3,268M (Scenario 2), and up to 52.5% or $5,567M (Scenario 3).
- Natural gas consumption would increase, over the Reference Scenario by 5.5% (Scenario 1), 7.7% (Scenario 2), and up to 28.9% (Scenario 3).

- Fuel oil consumption would increase, over the Reference Scenario by 823.7% (Scenario 1), 815.7% (Scenario 2), and up to 1,109.5% (Scenario 3).
- Coal consumption would increase, over the Reference Scenario by 47.2% (Scenario 1), 48.3% (Scenario 2), and up to 129.6% (Scenario 3).
- CO_2 emissions would increase, over the Reference Scenario by 29.4 Mton (Scenario 1), 31.0 Mton (Scenario 2), and up to 73.5 Mton (Scenario 3).
- SO_2 emissions would increase ,over the Reference Scenario by 2.3 Mton (Scenario 1), 2.3 Mton (Scenario 2), and up to 3.8 Mton (Scenario 3).
- NO_x emissions would increase, over the Reference Scenario by 658.3 kton (Scenario 1), 676.0 kton (Scenario 2), and up to 1,305.4 kton (Scenario 3).

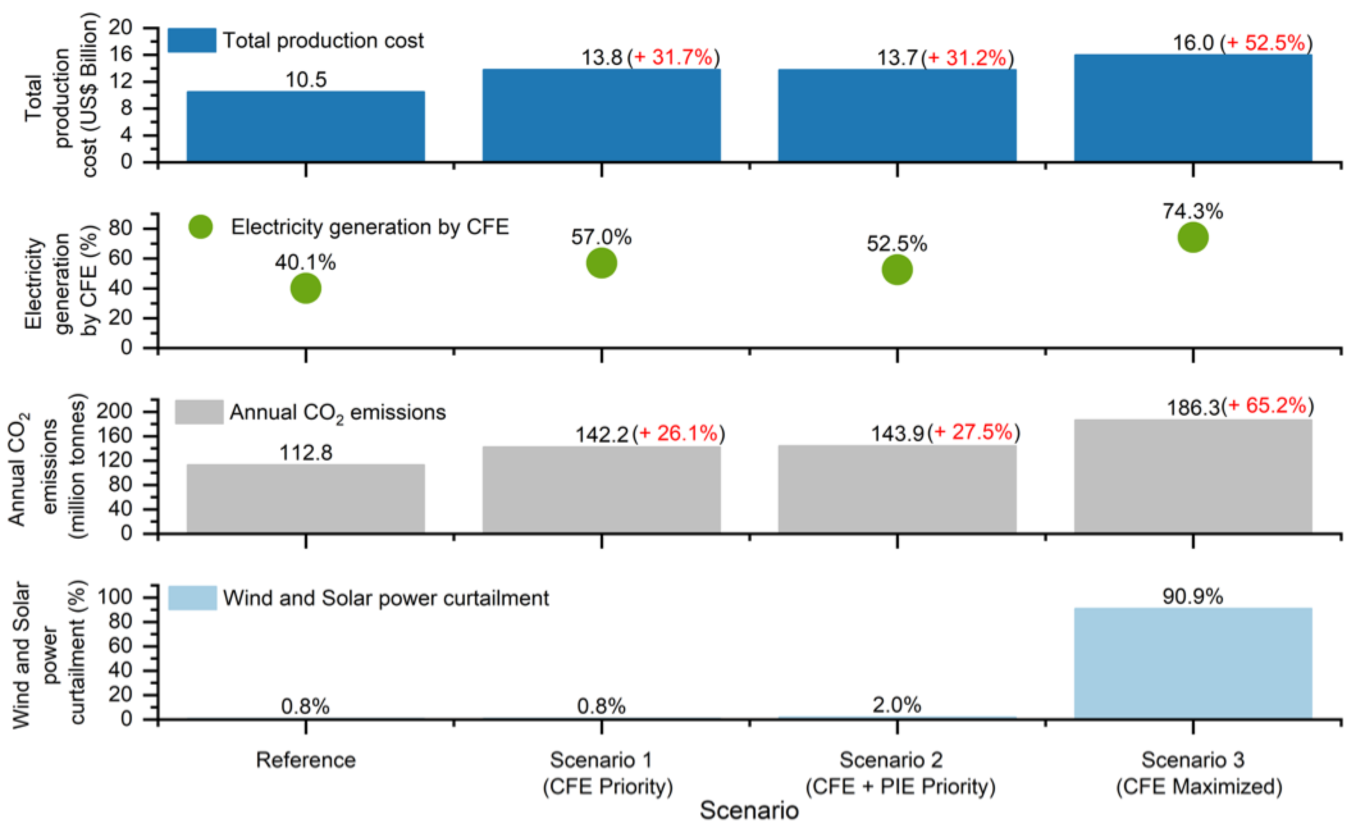

Figure E-1. Summary of Results Against the Reference Scenario

a PIE = Independent Energy Producer with a contract with CFE.

b Curtailment is a reduction in the output of a generator from what it could otherwise produce given available resources—typically on an involuntary basis. Source: https://www.nrel.gov/docs/fy14osti/60983.pdf.

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1 Introduction

In order to ensure that power systems provide reliable electricity service to customers at lowest cost, system operators must determine which power plants are utilized to provide energy at any given time. This problem, known as Unit Commitment and Economic Dispatch, is typically solved by allowing lowest cost plants to provide power when possible, subject to system and generator constraints.

In Mexico, numerous amendments have been approved and others are under discussion to significantly change Mexico's electricity legal framework and its market rules. These changes modify the order in which generation units are committed and dispatched, thus allowing state-owned power plants to have priority in supplying energy to the system.

In March 2021, a decree amending and supplementing provisions of Mexico's Electricity Industry Law (Ley de la Industria Eléctrica, LIE) was approved and then published in the Federal Official Gazette [2], but court challenges resulted in a permanent suspension of the LIE changes. In response, on October 1, 2021, the federal government created an initiative to amend Mexico's Constitution with a new energy reform [3]. Both bills broadly change the rules for electricity dispatch on the national grid and benefit the state-owned utility company (Comisión Federal de Electricidad [CFE]) and the power generation plants owned by its subsidiaries, thus displacing renewable energy plants and other fossil-fuel based privately owned power plants. The constitutional energy reform initiative would, if approved, increase even more the utilization of CFE-owned generation resources; it would eliminate the independent system operator (Centro Nacional de Control de Energía [CENACE]) as well as the Energy Regulatory Commission (Comisión Reguladora de Energía [CRE]), and it would cancel the energy contract mechanisms with the private sector, that were approved under the energy reform of 2013.

The results of the analysis described in this report are not a forecast of future effects of either the amendments to the LIE or the new initiative of energy reform. Instead, the results in this report represent the outcomes of the simulation of the hourly operation of the Mexican power system for the year ending August 31, 2021, under three possible scenarios that increase the level of generation of the state-owned power utility and which represent different interpretations of the amendments and the energy reform. The historical 12-month period ending August 31, 2021, was validated by the model, and it represents the Reference Scenario with which the others are compared.

We used the Scenario Analysis Interface for Energy Systems (SAInt) software [1] to create and run the production cost model of the Mexican power system, to first simulate its hourly operation for 1 year under the four scenarios, and then evaluate the impact of the new dispatch process for maximizing state-owned generation on the generation mix, the variable generation costs for providing electricity, the use of renewable energy sources and fossil fuels, and total emissions from the power sector.

2 Overview of the Production Cost Model of the Mexican Power System

This section provides an overview of the public data and information used to build the production cost model of the Mexican power system (including the three asynchronous power systems: the national interconnected power system, the Baja California power system, and the islanded Baja California Sur power system). The model was implemented in encoord's commercial software SAInt [1]. The model data and assumptions were reviewed by several experts of the Mexican power system. This section also includes a validation of the model.

A production cost model (a short-term operational model, or a unit commitment and economic dispatch model) of an electricity transmission network (e.g. the national power grid of a country or a region) is a linear mixed-integer optimization problem (with binary and continuous variables). The model simulates the hourly (or sub-hourly, e.g. 5-minute) operation of the system by defining the commitment[1] and dispatch[2] of electricity generators, of storage elements, and of flexible demand during a period of time (between 1 day and 1 year) with the goal of meeting electricity demand and the system reserve requirements, while considering all system generation, transmission, and demand constraints of the system and minimizing the variable costs of electricity generation (sum of fuel costs, variable operation and maintenance costs, and startup costs).

Power system operators use production cost models to economically commit and dispatch electricity generators, energy storage, and flexible demand. They can also be used by energy ministries, regulators, research organizations, market analysts, consultants, and many others to study how a power system would operate under different system scenarios and conditions and thus inform their decisions. For instance, a production cost model can be used to study how different potential changes to the power system (e.g., additional generation capacity, increased load, additional energy storage, additional operational reserve requirements, increased transmission capacity, etc.) might impact or challenge its bulk power system operations. Impacts on bulk power system operations can be analyzed in terms of electricity prices, electricity production costs (variable generation costs), emissions, transmission congestion, fuel consumption, generation dispatch decisions, ability of the system to meet electricity load and operational reserve requirements at every time during the time period modeled.

2.1 Electricity Demand

We modeled demand time series based on disaggregation across 9 control regions, 52 transmission regions, and 108 load zones as defined by the national power system operator ("Centro Nacional de Control de Energía" [CENACE]).

The demand profiles for 1 year (September 2020 – August 2021) [4] disaggregated per the 108 load zones were assigned to the corresponding transmission regions according to geographic and historical demand criteria. Figure 1 shows the annual electricity demand for each Mexican state.

1 Commitment is the decision that defines whether an electricity generator is online or not. Commitment variables are binary.

2 Dispatch is the decision that defines the electricity generation level of a generator. Dispatch variables are continuous.

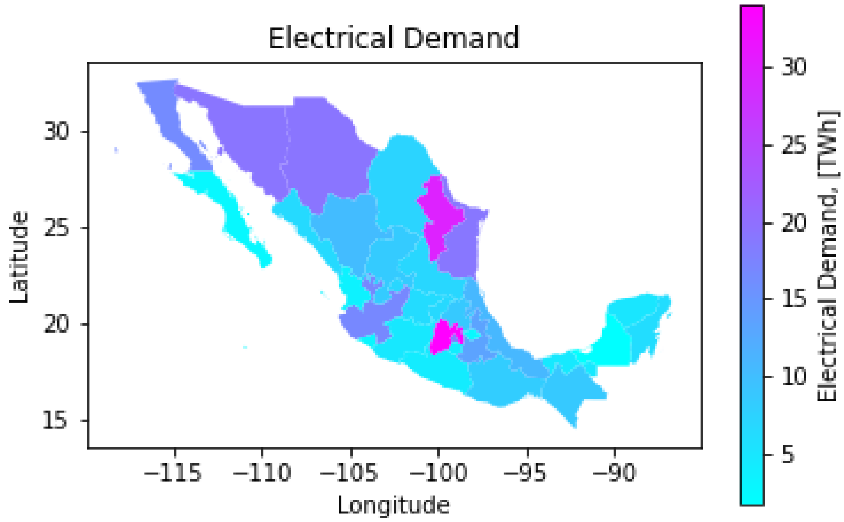

Figure 1. Annual demand for each Mexican state (September 2020 – August 2021)

2.2 Transmission Network

The transmission network representation was based on regional transmission limits defined by CENACE. The limits were based on the following sources:

- The 2019 Transmission Expansion Plan of CENACE (Programa de Ampliación y Modernización de la Red Nacional de Transmisión y Redes Generales de Distribución del Mercado Eléctrico Mayorista) [6] Table 4.2 of this publication shows the transmission capacities among the 52 transmission regions in 2018.
- Knowledge from subject matter experts of the Mexican power system.

Figure 2 shows the topological representation of the interconnections between transmission regions included in the model.

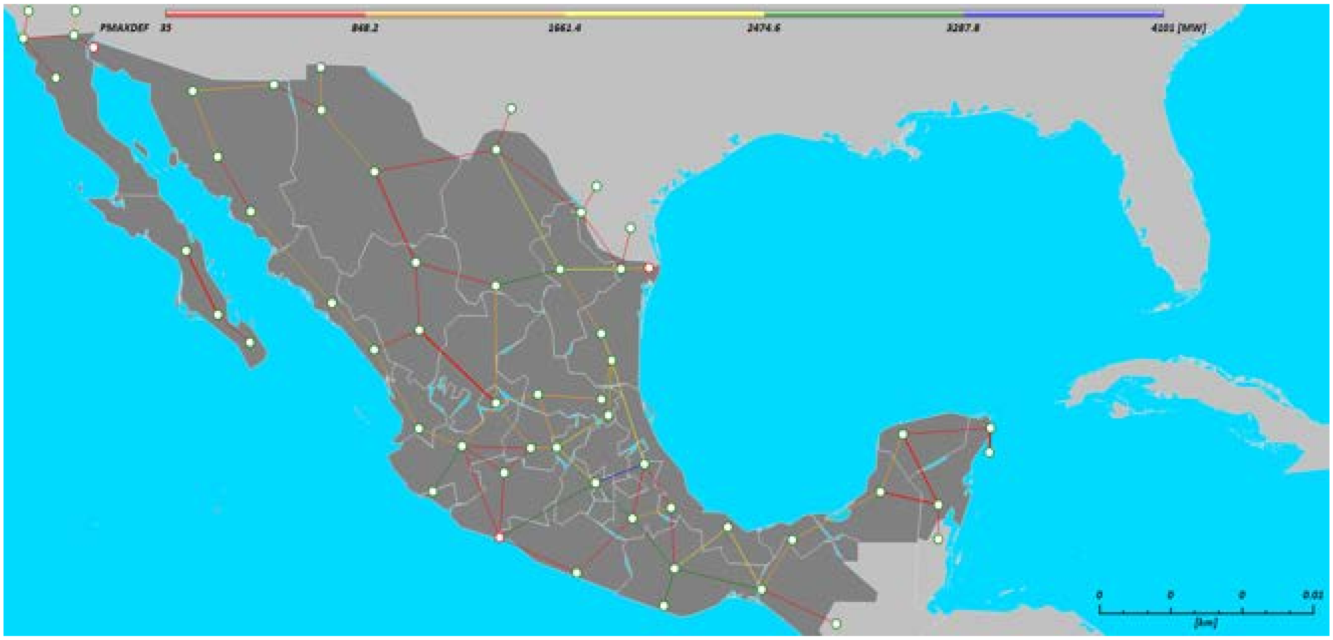

Figure 2. Topological representation of the interconnections between transmission regions included in the model

Colors indicate the maximum active power flow limits between the regions, as indicated in the legend.

2.3 Generation

The primary reference concerning electricity generators is the Capacity Expansion Plan of the Mexican Power System published by the Secretaría de Energía (SENER) [5]. It includes all the existing electric generators, including the technology type and fuel, the transmission region to which they are connected, generation capacity, average heat rate, minimum up-time, minimum down-time, and variable operation and maintenance costs.

The list of existing generators was reviewed and updated by encoord and several experts of the Mexican power system, and include generators installed after the El Programa para el Desarrollo del Sistema Eléctrico Nacional (PRODESEN) 2018 was published. The resulting operating capacities for each generation technology are shown in Table 1. Figure 3 shows the installed operational electricity generation capacity for each Mexican state.

Table 1. Operating Capacity for Each Generation Technology

Generation Technology	Operating Capacity (GW)
Combined Cycle	36.13
Steam Turbine: Coal	5.05
Steam turbine: Coke	0.54
Steam turbine: Natural gas	6.27
Steam turbine: Fuel oil	5.19
Gas turbine: Natural gas	3.26
Gas turbine: Diesel	1.05
Internal combustion: Diesel	0.16
Internal combustion: Fuel oil	0.34
Internal combustion: Natural gas	0.55
Nuclear	1.55
Hydroelectric	12.59
Geothermal	0.75
Bioenergy	0.47
Wind	7.16
Solar	5.85
Total	**86.91**

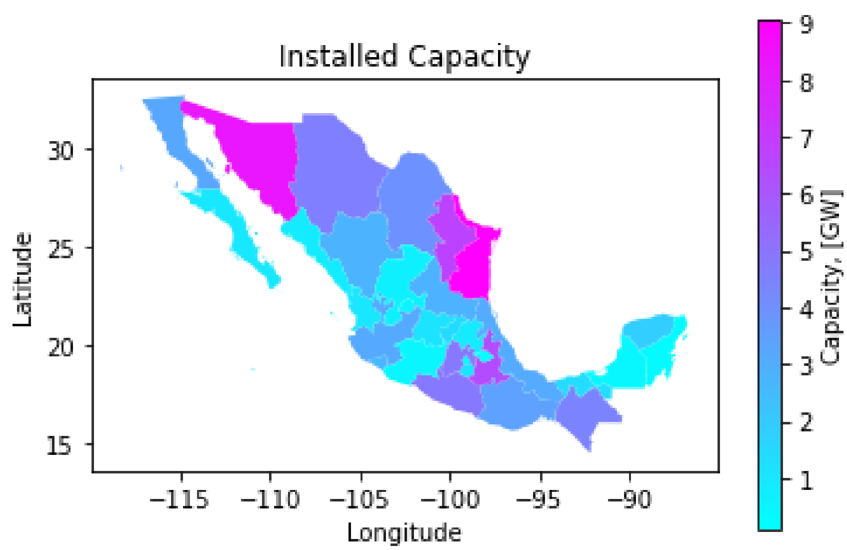

Figure 3. Installed operational electricity generation capacity for each Mexican state

2.3.1 Hydropower

The primary references used to model the hydroelectric generation is the report *Bases para un Centro Mexicano en Innovación de Energía Hidroeléctrica: Parte 1: Infraestructura Hidroeléctrica Actual* [7], a report published by the Mexican Institute of Water Technology (Instituto Mexicano de Tecnología del

Agua [IMTA n.d.]) and the weekly accumulated dispatchable hydroelectric generation curve (*Evolución Hidráulica - Curva de Generación Acumulada*), which is published by CENACE [8]. These documents contain the data to model the seasonality, availability, and variability of the hydropower plants of the Mexican power system. In addition, the hydroelectric generation reported by CENACE [9] for the 12-month period from September 2020 to August 2021 was used to model non-dispatchable and dispatchable hydro power. Figure 4 shows the installed operational hydroelectric generation capacity for each Mexican state.

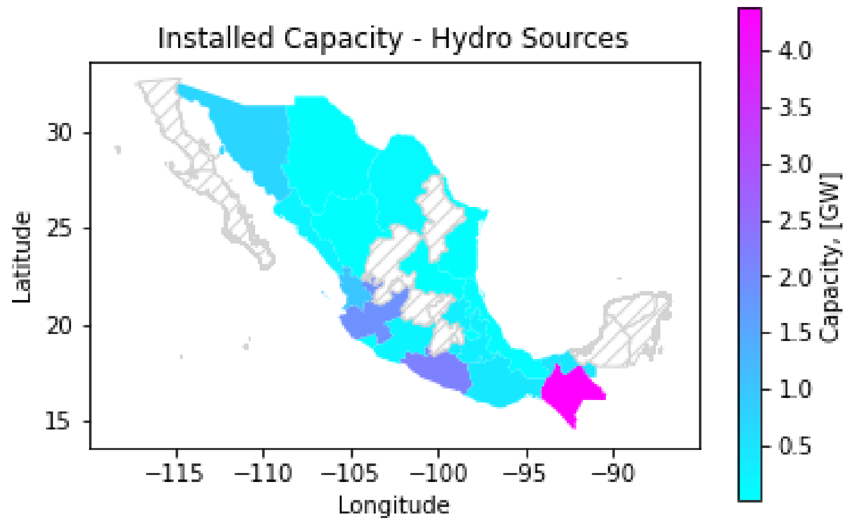

Figure 4. Installed operational hydroelectric generation capacity per Mexican state.

2.3.2 Wind and Solar Power

We used the Wind Integration National Dataset (WIND) Toolkit [10] and the National Solar Radiation Database (NSRDB) [11] of the U.S. National Renewable Energy Laboratory to develop the hourly electricity generation profiles of each wind and solar PV plant in Mexico [3]. The resulting electricity generation profiles were adjusted to match average capacity factors for wind and solar, shared by the Mexican wind and solar energy associations. Figures 5 and 6 show the installed operational wind and solar PV power generation capacity for each Mexican state.

3 2014 and 2019 were chosen as the weather years for wind and solar resource profiles.

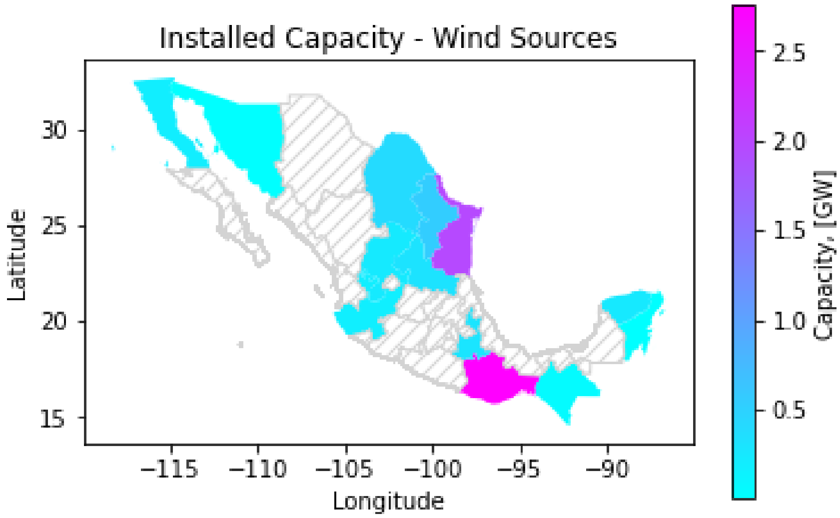

Figure 5. Installed operational wind power generation capacity for each Mexican state.

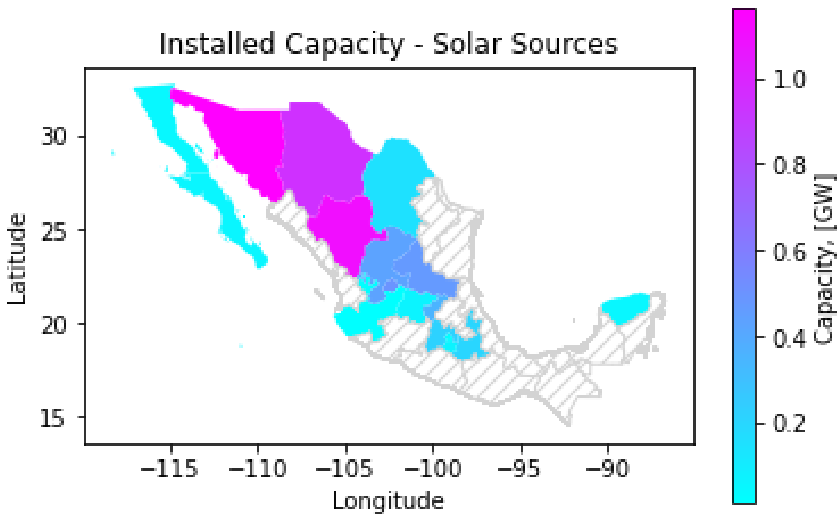

Figure 6. Installed operational solar PV power generation capacity for each Mexican state.

2.3.3 Conventional Thermal Power

Figure 7 shows the installed operational thermal power generation capacity per Mexican state.

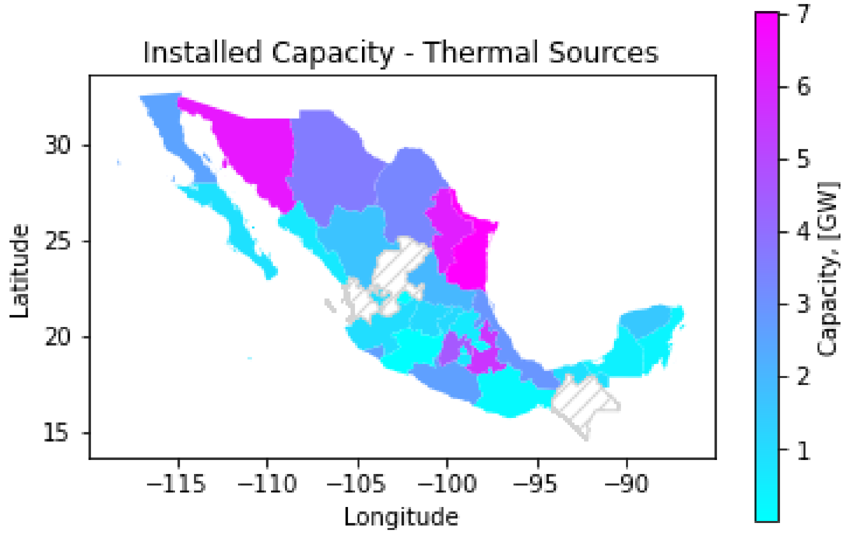

Figure 7. Installed operational thermal power generation capacity for each Mexican state.

2.4 Fuel Prices and Emissions

Fuel prices for the 12-month period September 2020 to August 2021 were used. In addition, fuel transportation costs were considered for natural gas and fuel oil [12]. Figures 8, 9, 10, and 11 show the coal, fuel oil, diesel, and natural gas prices, respectively. Figure 12 zooms into the natural gas prices to visualize the difference between regional costs by reducing the wide range of costs caused by very high prices experienced during 9 days in February 2021 due to extreme weather in Texas and Northern Mexico.

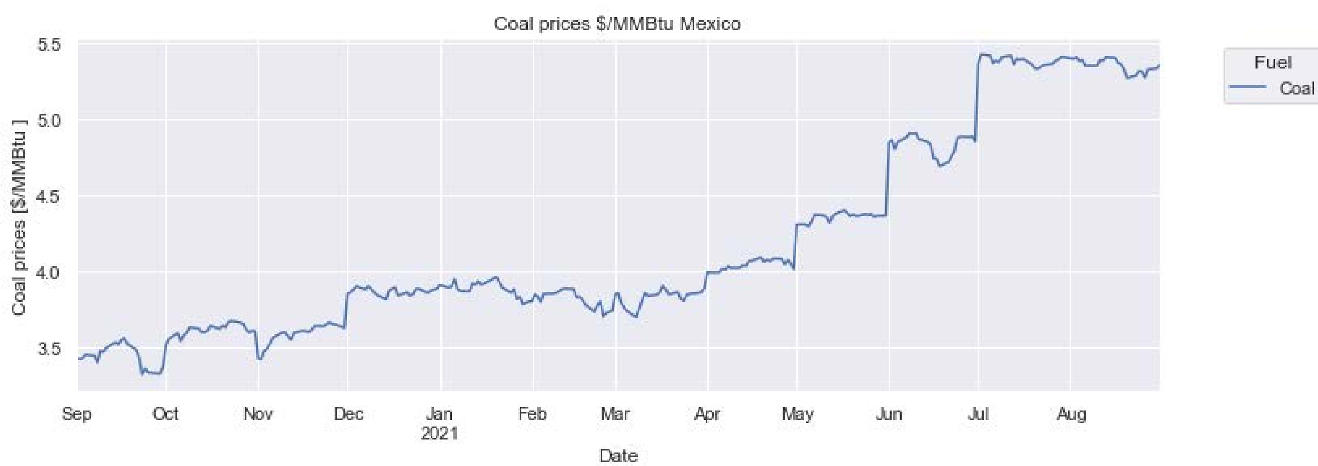

Figure 8. Coal prices

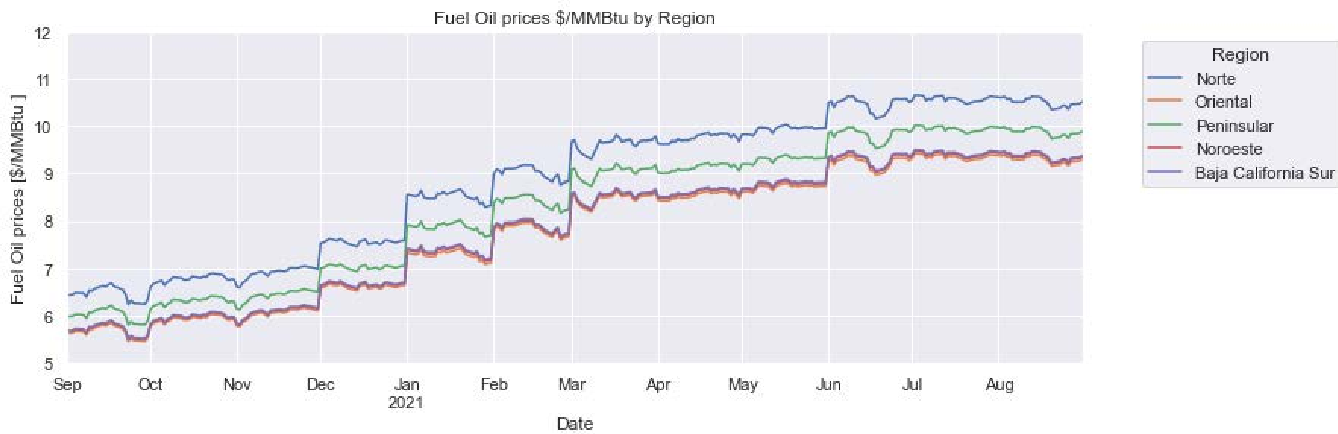

Figure 9. Fuel oil prices

Figure 10. Diesel prices

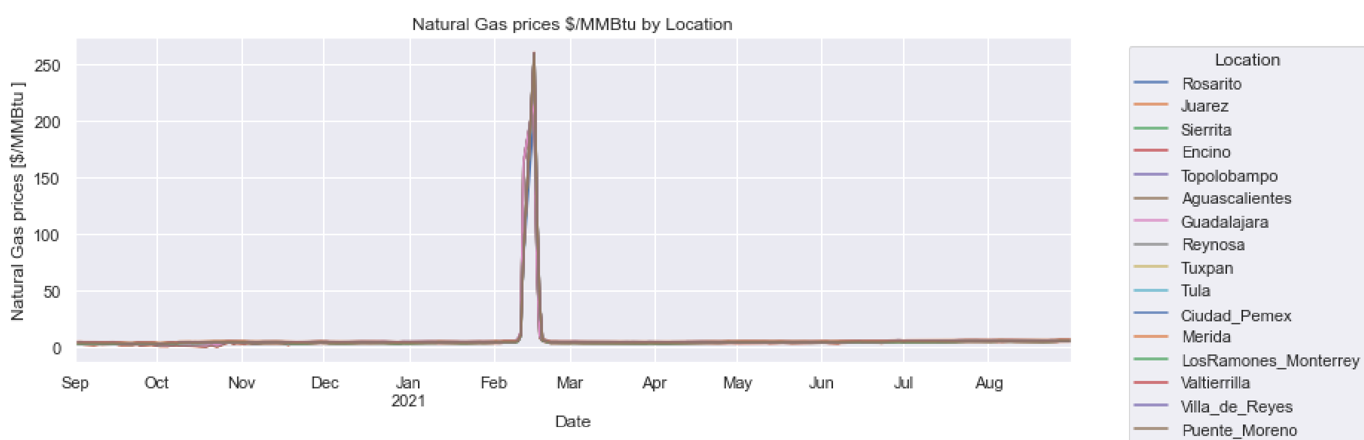

Figure 11. Natural gas prices

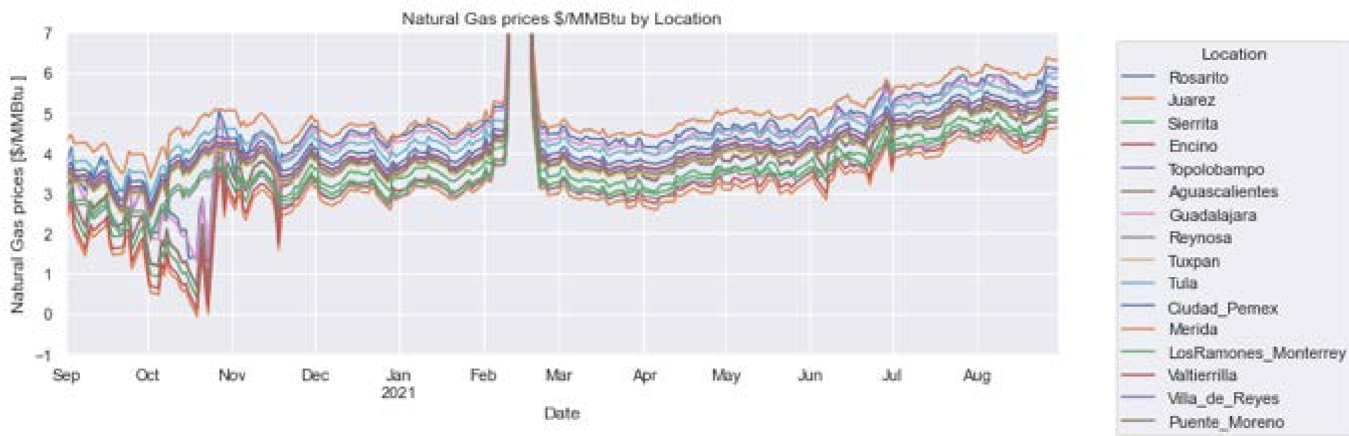

Figure 12. Natural gas prices (zoomed)

Emissions factors for each fuel were obtained using the database from the U.S. Energy Protection Agency [13] and the Commission for Environmental Cooperation [14].

2.4.1 Fuel Consumption Functions

The fuel consumption function for each thermal power plant was calculated from the average heat rates published in the "Capacity Expansion Plan of the Mexican Power System", which was published by SENER [5]. Instead of using an average heat rate, linear fuel consumption functions per generator type and size were assumed to consider how thermal power plant efficiencies vary as a function of generation level. For the thermal power plants not included in the database, an approximate heat rate function was used based on other power plants of similar technology and capacity.

2.5 Generator Outages due to Maintenance and Forced Outages

The programmed maintenance rates in the "Pronóstico de Capacidad de Generación en Mantenimiento 2021 -2023", [15], which was published by CENACE in their monthly report of February 2021, were used to model the generators' planned outages that were due to maintenance. The total annual generation outages that were due to maintenance were estimated to be around 21 terawatt-hours (TWh), and most of the maintenance was scheduled during the first and last quarters of the year, when the system demand is low. The document "Tasas de Salida Forzada 2019 -2022" [16], which was published by CENACE in the same monthly report, was used to model unplanned outages that were due to failures. Based on these estimated rates, generators were set to unavailable, for maintenance and failures, for a specific number of days throughout the year.

Planned and unplanned outages were modeled only for thermal power plants and geothermal plants with an installed capacity equal to or greater than 320 megawatts (MW). The duration of the planned annual maintenance for each generator was assumed to be continuous, and the assigned number of days was based on the outage rate per type of generation technology. On the other hand, unplanned outages due to failures were modeled with multiple failures randomly assigned during the whole year.

3 Validation of the Mexican Power System Model

The generation mix (by technology) of the Mexican power system was successfully validated for the period September 2020 to August 2021 against actual electricity generation for each technology published by CENACE [9]. The annual electricity imports were assumed to be equivalent to the import during 2020, the data for which were obtained from the CENACE's 2020 Transmission Expansion Plan [6]. Figure 13 compares the annual generation mix from SAInt's production cost modeling outputs and the actual generation reported by CENACE.

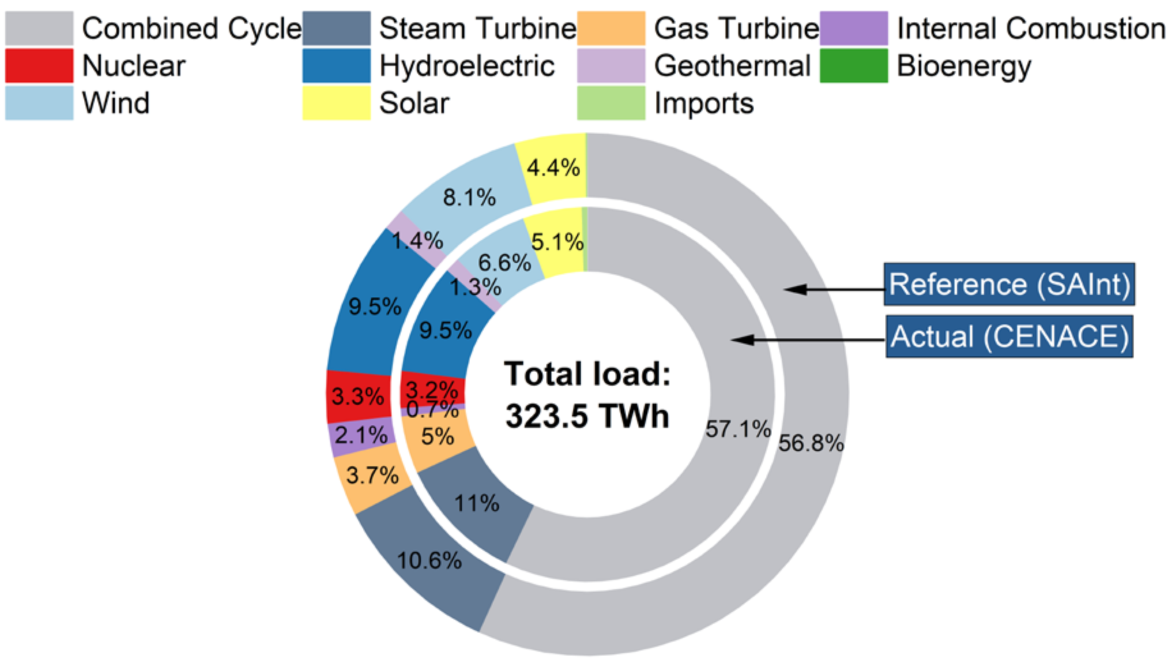

Figure 13. Annual generation mix - SAInt modeling outputs versus actual numbers by CENACE

Figure 14 compares the actual monthly generation mix reported by CENACE (a), and SAInt's production cost modeling outputs (b).

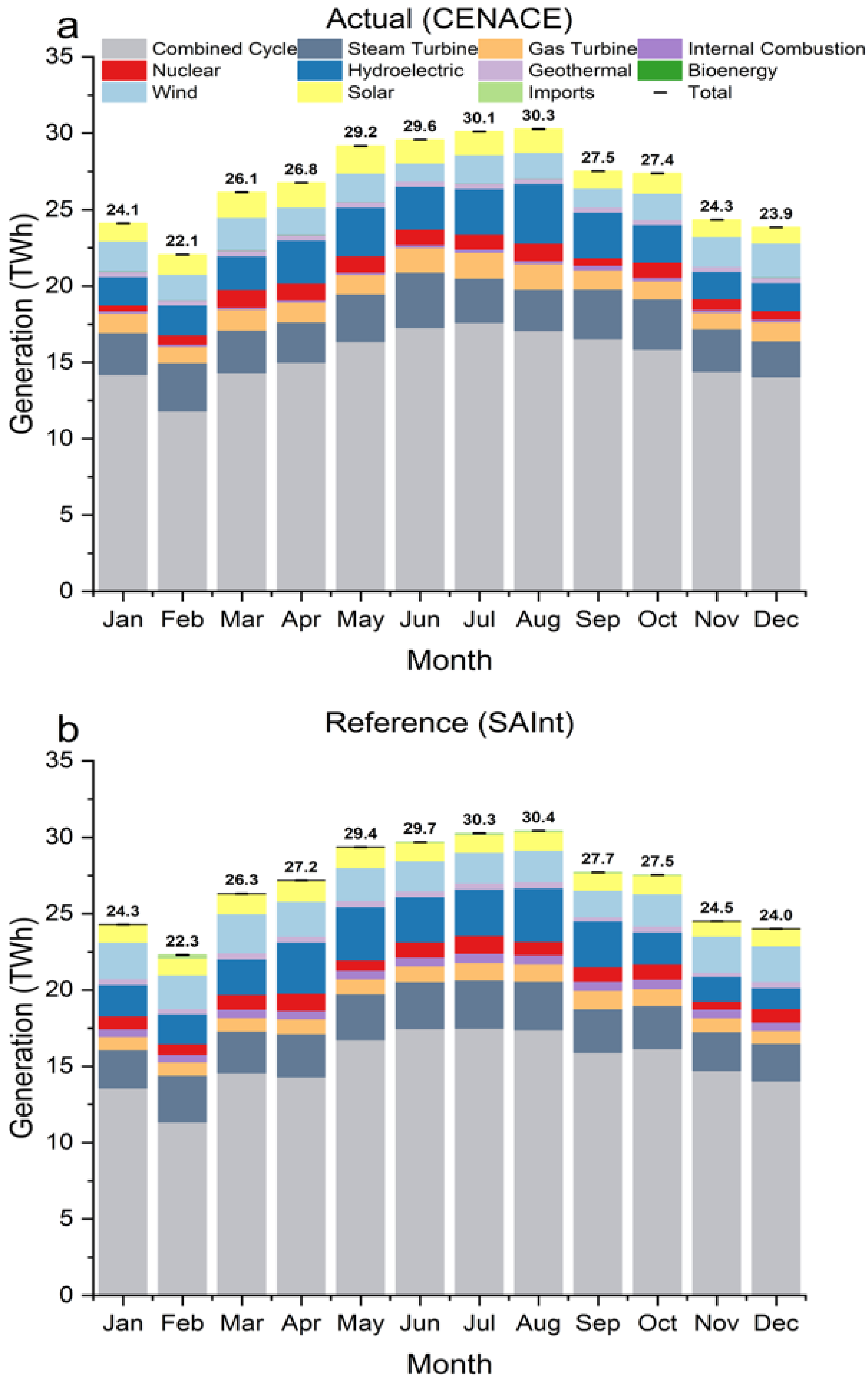

Figure 14. Monthly generation mix - SAInt modeling outputs and Actual by CENACE

Similarly, Figure 15 and Figure 16 compare the average weekly dispatch per generation technology from SAInt's production cost modeling outputs and the actual dispatch reported by CENACE.

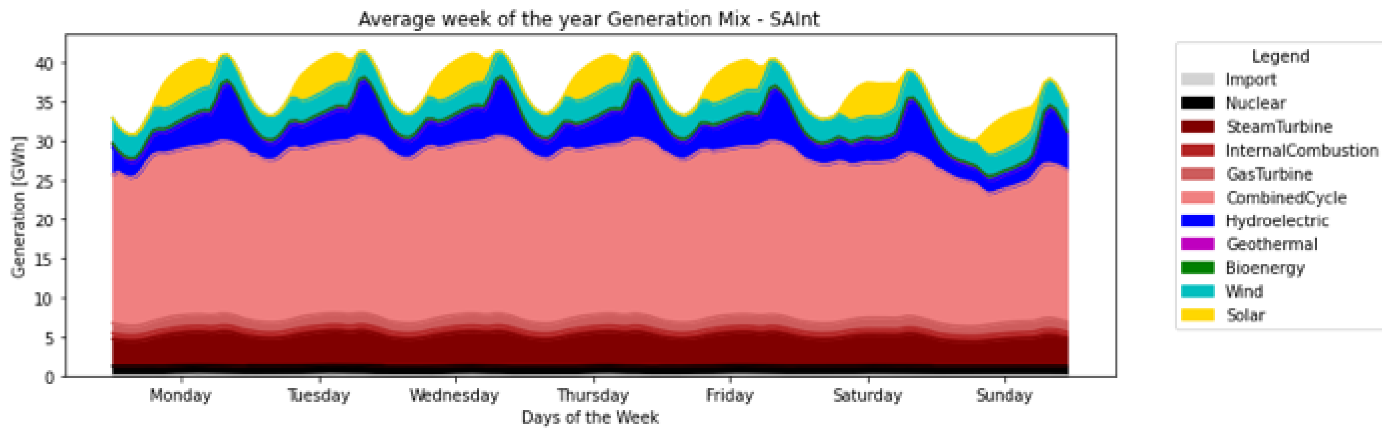

Figure 15. Average weekly generation dispatch: SAInt modeling outputs

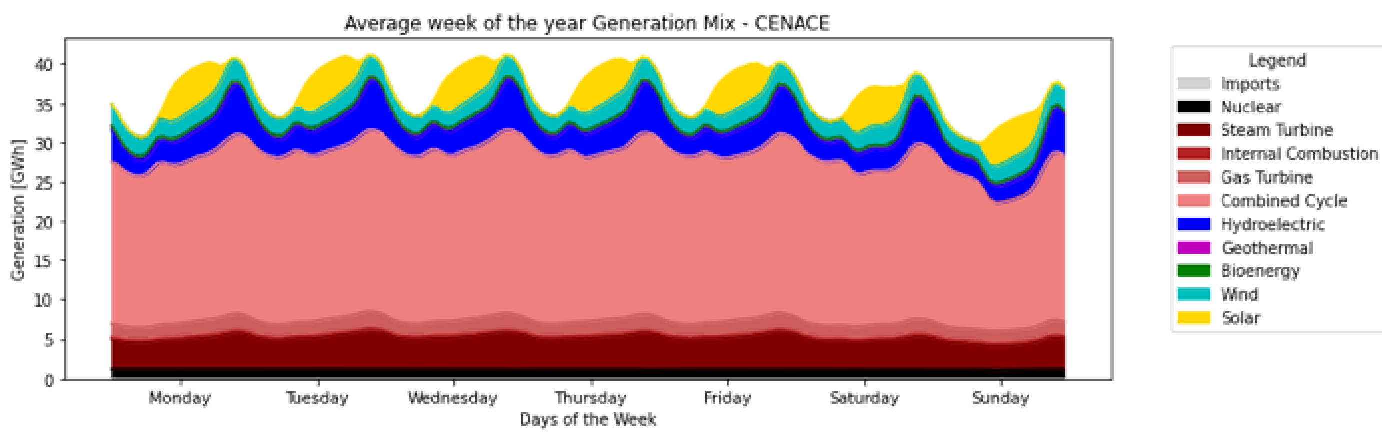

Figure 16. Average weekly generation dispatch: Actual by CENACE

Appendix A includes figures that compare the average weekly dispatch for each generation technology for four different months (January, April, July, and October) from SAInt's production cost modeling outputs and the actual dispatch reported by CENACE.

4 Scenario Descriptions

4.1 Reference Scenario

The Reference Scenario simulates the current Mexican power system before the amendments to Mexico's electricity legal framework and market rules that seek to benefit power generation of the state-owned utility CFE. This scenario of the Mexican power system simulates a competitive electricity market with privately and publicly owned electricity generators.

For this scenario, the following additional assumptions are made:

- Cogeneration units owned by the publicly owned electricity generators, CFE and PEMEX, are modeled to generate constantly at a minimum of 85% of their maximum operational capacity.
- Cogeneration units owned by privately owned electricity generators are modeled to generate constantly at a minimum of 70% of their maximum operational capacity.
- Privately owned generators holding self-consumption contracts are modeled to generate constantly at 95% of their maximum operational capacity.

4.2 Scenario 1: CFE Priority

In this scenario, all generators owned by CFE, except for diesel-fueled generators and open-cycle gas turbine generators, are forced to be online and supply electricity to the grid between their minimum[4] and maximum generation levels (except during planned and unplanned outages). For this scenario, the first two additional assumptions of the Reference Scenario are considered, and the third one about privately owned generators holding self-consumption contracts is not considered, which allows these generators to be dispatched freely.

4.3 Scenario 2: CFE + PIE Priority

This scenario is the same as Scenario 1, with one additional assumption, the privately owned electricity generators that hold independent energy producer contracts (PIE contracts) with the government are prioritized in the same way as the generators owned by CFE. In other words, the generators with PIE contracts are also forced to be online and supply electricity to the grid between their minimum and maximum generation levels (except during planned and unplanned outages).

4.4 Scenario 3: CFE Maximized

Scenarios 1 and 2 force the prioritized generators to be online unless they are unavailable because of planned or unplanned outages. Scenario 3 models the potential impact of maximizing state-owned generation. It defines the dispatch order by placing state-owned generators above privately owned

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4 The minimum generation limit of each thermal generation unit is calculated based on the data presented in the Wholesale Electricity Market Annual Report 2019 ("Reporte Anual del Mercado Eléctrico Mayorista 2019") published by ESTA International, the independent monitor of the Mexican Electricity Market. Table 46 of the report provides yearly reference values (2017, 2018, and 2019) from CENACE by type of thermal generation technology. The minimum generation percentage per thermal generator technology (yearly reference values) were averaged and multiplied by the maximum generation (installed capacity in megawatts) to obtain the minimum generation limit in megawatts of each generator based on the type of thermal generation technology.
Energy Strategy and Technology Associates (ESTA) International, "Reporte Anual del Mercado Eléctrico Mayorista 2019," [Online]. https://www.gob.mx/cms/uploads/attachment/file/553784/Reporte_Anual_2019_del_Monitor_Independiente_del_Mercado.pdf.

generation. This is the result of applying adjustment factors to each generator's variable electricity generation costs based on their priority level. These adjustment factors were used for the purpose of directly impacting on the generation dispatch merit to maximize state-owned generation. To fairly compare the production costs on all scenarios, these adjustment factors were excluded from the production cost figures.

- The generators with the highest priority are those owned by CFE (excluding the diesel-fueled and open-cycle gas turbine generators). No adjustment factor is applied to their variable generation costs.
- The generators with second priority are the privately owned generators with PIE contracts. An adjustment factor of $150/MWh (megawatt-hours) is applied to their variable generation costs.
- All other generators (mainly the privately owned ones that are not cogeneration) have third priority. An adjustment factor of $300/MWh is applied to their variable generation costs.

The adjustment factors were chosen to represent the hierarchical priority among CFE generators, privately owned generators with PIE contracts, and all other generators in a way that does not interfere with their different variable generation costs. The only period when these adjustment factors do not have this impact at all hours is during the 9-day period in February that saw very high natural gas prices. The differences in adjustment factors were chosen to be higher than the 95th percentile ($147/MWh) of the marginal variable generation cost across all transmission regions and all hours of the year in the Reference Scenario, excluding the 9-day period in February that saw exceptionally high natural gas prices.

5 Results

This section highlights the main results obtained from running the production cost model of the Mexican power system under the four scenarios described in the previous section. Some of the modeling results presented in this section are categorized by type of generator owner (publicly owned and privately owned generators) and type of power supply contracts.

The public electricity generation companies in Mexico include the state-owned utility company "Comisión Federal de Electricidad" (CFE) and the national petroleum company "Petróleos Mexicanos" (PEMEX). These public companies hold the following type of power supply contracts:

- Market Contract ("Mercado")
- Legacy Contract for Basic Supply ("Contrato Legado para Suministro Básico" (CLSB))
- Cogeneration Contract ("Cogeneración")

On the other hand, private electricity generation companies in Mexico hold the following type of power supply contracts:

- Market Contract ("Mercado")
- Self-Consumption Contract ("Autoabastecimiento")
- Cogeneration Contract ("Cogeneración")
- Independent Energy Producer Contract ("Productor Independiente de Energía" (PIE))
- Long-Term Auction Contract ("Subasta de Largo Plazo" (SLP))

5.1 Generation Mix

Figure 17 shows the annual generation mix, in terms of percentages. Tables 2 and 3 show the annual generation mix for the four scenarios per generation technology and per generator owner and contract type, respectively.

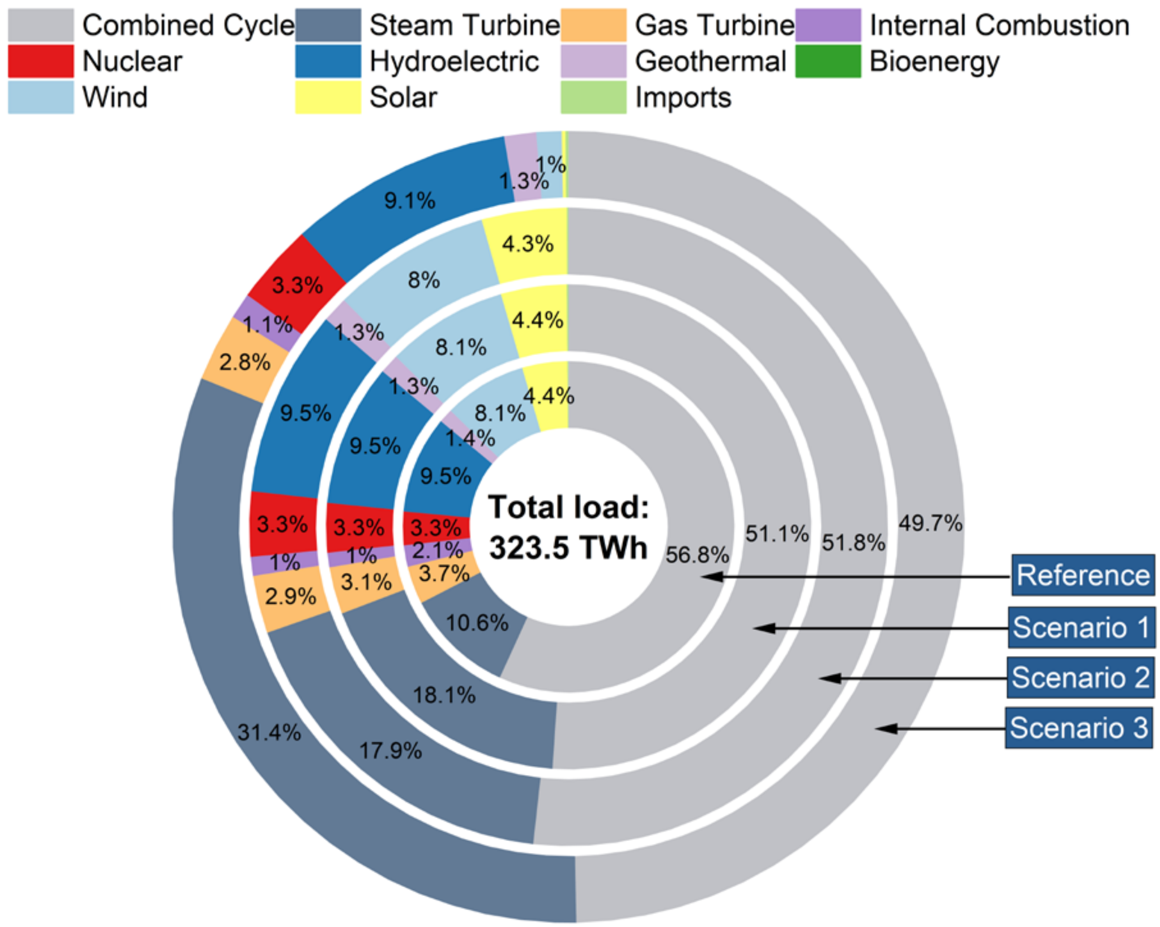

Figure 17. Percentage of Annual Generation Mix by Technology –Scenarios 1, 2 and 3 Compared to the Reference Scenario

Table 2. Annual Electricity Mix for Each Generation Technology

Generation (TWh)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total generation	**323**	**[%]**	**323**	**[%]**	**323**	**[%]**	**323**	**[%]**
Combined cycle	183.76	56.81	165.13	51.05	167.44	51.76	160.71	49.69
Steam turbine: Coal	14.37	4.44	19.50	6.03	19.65	6.07	32.34	10.00
Steam turbine: Coke	4.49	1.39	0.13	0.04	0.12	0.04	0.09	0.03
Steam turbine: Fuel oil	0.86	0.27	15.20	4.70	15.03	4.65	22.10	6.83
Steam turbine: Natural gas	14.54	4.50	23.84	7.37	22.93	7.09	47.13	14.57
Gas turbine: Diesel	1.60	0.49	1.60	0.50	1.56	0.48	1.58	0.49
Gas turbine: Natural gas	10.42	3.22	8.51	2.63	7.91	2.45	7.40	2.29
Internal combustion: Diesel	1.11	0.34	0.03	0.01	0.03	0.01	0.03	0.01
Internal combustion: Fuel oil	2.42	0.75	2.10	0.65	2.10	0.65	2.34	0.72
Internal combustion: Natural gas	3.22	1.00	1.01	0.31	0.96	0.30	1.04	0.32
Nuclear	10.65	3.29	10.65	3.29	10.65	3.29	10.65	3.29
Hydroelectric: Reservoir	24.50	7.57	24.50	7.57	24.50	7.57	24.50	7.58
Hydroelectric: Run of river	6.25	1.93	6.25	1.93	6.18	1.91	5.08	1.57
Geothermal	4.45	1.38	4.22	1.31	4.22	1.31	4.22	1.31
Bioenergy: Biogas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bioenergy: Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	26.21	8.10	26.21	8.10	25.99	8.03	3.31	1.02
Solar: Photovoltaics	14.08	4.35	14.07	4.35	13.81	4.27	0.37	0.12
Solar: Solar thermal	0.12	0.04	0.12	0.04	0.11	0.03	0.12	0.04
Import	0.40	0.12	0.38	0.12	0.28	0.09	0.41	0.13

Table 3. Annual Electricity Mix for Each Generator Owner and Contract Type

Generation (TWh)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total generation	**323**	**[%]**	**323**	**[%]**	**323**	**[%]**	**323**	**[%]**
Public agent total	129.63	40.08	184.41	57.01	169.85	52.51	240.26	74.28
CFE: Market	27.28	8.43	54.34	16.80	49.23	15.22	82.82	25.61
CFE: CLSB	87.36	27.01	115.11	35.59	105.97	32.76	140.86	43.55
CFE: Cogeneration	2.95	0.91	2.95	0.91	2.95	0.91	3.46	1.07
PEMEX: Cogeneration	12.05	3.72	12.01	3.71	11.71	3.62	13.13	4.06
Private agent total	193.44	59.80	138.68	42.87	153.34	47.40	82.77	25.59
Private: PIE	94.00	29.06	72.01	22.26	99.89	30.88	70.54	21.81
Privat: Cogeneration	12.12	3.75	12.33	3.81	11.83	3.66	9.97	3.08
Private: Self-consumption	51.82	16.02	25.16	7.78	18.74	5.79	1.21	0.37
Private: Market	16.92	5.23	11.81	3.65	8.74	2.70	0.61	0.19
Private: SLP	17.57	5.43	17.36	5.37	14.13	4.37	0.39	0.12
Private: CLSB	1.01	0.31	0.01	0.00	0.00	0.00	0.06	0.02
Imports	0.40	0.12	0.38	0.12	0.28	0.09	0.41	0.13

Table 2 provides an overview of the overall generation mix of the Mexican power system in the different scenarios. It can be observed that prioritizing state-owned generation would significantly increase the dependency on steam turbine power plants and decrease the dependency on combined cycle power plants.

As shown in Table 3, the share of annual electricity generation by publicly owned generators would increase from 40% to 57% (Scenario 1), 53% (Scenario 2), or 74% (Scenario 3). This would correspond to a decrease in the share of annual electricity generation by privately owned generators from 60% to 43% (Scenario 1), 47% (Scenario 2), or 26% (Scenario 3). This shift in generation mix could impact power system reliability as a result of higher forced outage rates of older publicly owned power plants compared to newer privately owned power plants[5].

Wind and solar curtailment under the Reference Scenario is 0.32 TWh, which is equivalent to 0.8% of available wind and solar generation. Under Scenario 1, these figures remain the same. Under Scenario 2, wind and solar curtailment increases by 0.49 TWh, reaching 2% (0.81 TWh) of available wind and solar generation. Maximizing state-owned generation in Scenario 3, results in wind and solar curtailment of 23.22 TWh and 13.71 TWh, respectively. This total curtailment of 36.93 TWh represents 90.93% of wind and solar available generation.

Appendix B includes figures that show the annual and monthly generation mix per generation technology and the annual generation mix per generator owner and contract type for the four scenarios. It also

5 CFE has five generation companies that together comprise 155 power plants. A 2019 federal audit indicated that the average age of the CFE power plants was between 33.5 and 41.8 years. Meanwhile, the average age of the privately owned PIE power plants that hold PIE contracts with CFE is 12.1 years old. https://www.asf.gob.mx/Trans/Informes/IR2019b/Documentos/Auditorias/2019_0431_a.pdf
Moreover, the oldest privately owned power plant with a self-supply contract was built in 2004, and the average age of all privately owned power plants with self-supply contracts is less than 20 years.

includes figures that show the average weekly dispatch per generation technology for the year and for four different months (January, April, July, and October) for the four scenarios.

5.2 Annual Production Costs

Tables 4, 5, and 6 show the annual production costs for the four scenarios per cost type, per generation technology, and per generator owner and contract type, respectively.

Table 4. Annual Production Costs for Each Type of Cost

Costs ($million)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total production cost	**10,481**	**[%]**	**13,803**	**[%]**	**13,748**	**[%]**	**16,047**	**[%]**
Total fuel cost	9,401	89.70	12,799	92.73	12,790	93.03	14,853	92.55
Natural gas	7,630	72.80	8,594	62.2	8,586	62.45	9,477	59.05
Fuel oil	303	2.89	2,787	20.1	2,787	20.27	3,407	21.23
Diesel	577	5.51	355	2.57	355	2.58	355	2.21
Coal	680	6.49	983	7.12	983	7.15	1,535	9.57
Coke	134	1.28	4	0.03	4	0.03	3	0.02
Uranium	76	0.73	76	0.55	76	0.55	76	0.47
Total variable operation and maintenance cost	777	7.41	746	5.41	750	5.46	822	5.12
Total startup cost	102	0.97	69	0.50	69	0.50	169	1.06
Imports	202	1.92	189	1.37	139	1.01	203	1.26

Table 5. Annual Production Costs for Each Generation Technology

Costs ($M)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total production cost	**10,481**	**[%]**	**13,803**	**[%]**	**13,748**	**[%]**	**16,047**	**[%]**
Combined cycle	6,431	61.36	5,845	42.34	5,845	42.52	6,129	38.20
Steam turbine: Coal	731	6.97	1,026	7.43	1,026	7.46	1,603	9.99
Steam turbine: Coke	148	1.41	4	0.03	4	0.03	3	0.02
Steam turbine: Fuel oil	144	1.37	2,679	19.41	2,679	19.48	3,323	20.70
Steam turbine: Natural gas	1,138	10.85	2,875	20.83	2,873	20.89	3,600	22.43
Gas turbine: Diesel	359	3.43	360	2.61	359	2.61	360	2.24
Gas turbine: Natural gas	617	5.89	495	3.59	492	3.58	476	2.96
Internal combustion: Diesel	237	2.26	9	0.06	9	0.06	9	0.06
Internal combustion: Fuel oil	185	1.76	164	1.19	164	1.20	179	1.11
Internal combustion: Natural gas	192	1.83	61	0.44	61	0.44	66	0.41
Nuclear	97	0.93	97	0.70	97	0.71	97	0.61

Costs ($M)	Reference		Scenario 1		Scenario 2		Scenario 3	
Hydroelectric: Reservoir	0	0.00	0	0.00	0	0.00	0	0.00
Hydroelectric: Run of river	0	0.00	0	0.00	0	0.00	0	0.00
Geothermal	0	0.00	0	0.00	0	0.00	0	0.00
Bioenergy: Biogas	0	0.00	0	0.00	0	0.00	0	0.00
Bioenergy: Biomass	0	0.00	0	0.00	0	0.00	0	0.00
Wind	0	0.00	0	0.00	0	0.00	0	0.00
Solar: Photovoltaics	0	0.00	0	0.00	0	0.00	0	0.00
Solar: Solar thermal	0	0.00	0	0.00	0	0.00	0	0.00
Import	202	1.92	189	1.37	139	1.01	203	1.26

Table 6. Annual Production Costs for Each Generator Owner and Contract Type

Costs ($million)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total production cost	**10,481**	**[%]**	**13,803**	**[%]**	**13,748**	**[%]**	**16,047**	**[%]**
Public agent total	4,446	42.42	10,360	75.06	10,309	74.98	12,562	78.28
CFE: Market	1,211	11.55	5,434	39.37	5,411	39.36	6,636	41.35
CFE: CLSB	1,948	18.59	3,642	26.39	3,614	26.29	4,547	28.33
CFE: Cogeneration	308	2.94	308	2.23	308	2.24	334	2.08
PEMEX: Cogeneration	979	9.34	976	7.07	975	7.09	1,045	6.51
Private agent total	5,833	55.66	3,254	23.57	3,300	24.01	3,283	20.46
Private: PIE	2,883	27.51	2,049	14.85	2,137	15.54	2,497	15.56
Private: Cogeneration	699	6.67	705	5.11	703	5.11	654	4.08
Private: Self-consumption	1,731	16.52	232	1.68	212	1.54	39	0.24
Private: Market	348	3.32	149	1.08	139	1.01	66	0.41
Private: SLP	115	1.10	109	0.79	100	0.73	4	0.02
Private: CLSB	57	0.55	10	0.07	10	0.07	22	0.14
Imports	202	1.92	189	1.37	139	1.01	203	1.26

As shown in Table 4, the main cost of production is fuel cost, which accounts for around 90% (or more) of the total cost in every scenario. As shown in Tables 4, 5, and 6, prioritizing publicly owned generators would cause a substantial increase in the generation from steam turbines and in consumption of fuel oil and coal, which results in increased production costs.

Prioritizing state owned generation would increase annual electricity production costs by 32% or $3,322M (Scenario 1), 31% or $3,268M (Scenario 2), or else 53% or $5,567M (Scenario 3). The relative increase in annual electricity production costs would be higher in Scenarios 1 and 3 if the extremely high natural gas prices experienced during the 9 days of February depicted in Figure 11 were not considered. If fuel costs (and the electricity import costs driven by the high natural gas prices) were not considered in the analysis, the prioritization of state-owned generation would increase annual electricity production costs by 37% instead of 32% (Scenario 1), 30% instead of 31% (Scenario 2), or 71% instead of 53% (Scenario 3). During the 9 days of February that saw exceptionally high natural gas prices, the total fuel costs for the Mexican power system amounted to $2,184M in the Reference Scenario, and $2,527M, $3,067M, and $2,030M in Scenarios 1, 2, and 3, respectively.

5.3 Fuel Consumption

Table 7 shows the annual fuel consumption for the four scenarios. Prioritizing state-owned generation would increase natural gas consumption by 6% or 2,252 million cubic meters (Mm^3) (Scenario 1), or 8% or 3,145 Mm^3 (Scenario 2), or else 29% or 11,720 Mm^3 (Scenario 3). Fuel oil consumption would increase by 824% or 2,192 million gallons (Mgal) (Scenario 1), or 816% or 2,171 Mgal (Scenario 2), or else 1,109% or 2,953 Mgal (Scenario 3). Coal consumption would increase by 47% or 3.88 million tons/tonnes (Mton) (Scenario 1), or 48% or 3.97 Mton (Scenario 2), or else 130% or 10.65 Mton (Scenario 3).

Table 7. Annual Fuel Consumption

Fuel Consumption	Reference	Scenario 1	Scenario 2	Scenario 3
Natural gas [Mm3]	40,589	42,841	43,734	52,308
Fuel oil (Mgal)	266	2,458	2,437	3,219
Diesel (Mgal)	185	112	109	113
Coal (kton)	8,218	12,101	12,190	18,868
Coke (kton)	1,656	50	45	35
Uranium (ton)	166	166	166	166

5.4 Emissions

5.4.1 CO_2 Emissions

Table 7 and Table 8 show the annual CO_2 emissions for the four scenarios per fuel and per generator owner and contract type, respectively.

Table 8. Annual CO_2 Emissions for Each Generation Technology

CO_2 emissions (kton)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total	**112,791**	**[%]**	**142,224**	**[%]**	**143,858**	**[%]**	**186,308**	**[%]**
Natural gas	77,516	68.73	81,818	57.53	83,523	58.06	99,899	53.62
Fuel oil	2,991	2.65	27,626	19.42	27,388	19.04	36,174	19.42
Diesel	1,897	1.68	1,154	0.81	1,116	0.78	1,158	0.62
Coal	21,293	18.88	31,353	22.05	31,583	21.95	48,886	26.24
Coke	9,094	8.06	273	0.19	248	0.17	192	0.10

Table 9. Annual CO_2 Emissions for Each Generator Owner and Contract Type

CO_2 emissions (kton)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total	**112,791**	**[%]**	**142,224**	**[%]**	**143,858**	**[%]**	**186,308**	**[%]**
Public agent total	52,326	46.39	108,310	76.15	104,051	72.33	157,613	84.60
CFE: Market	11,242	9.97	46,867	32.95	45,154	31.39	71,505	38.38
CFE: CLSB	31,162	27.63	51,558	36.25	49,096	34.13	75,097	40.31
CFE: Cogeneration	2,261	2.00	2,261	1.59	2,261	1.57	2,555	1.37
PEMEX: Cogeneration	7,661	6.79	7,624	5.36	7,539	5.24	8,456	4.54
Private agent total	60,465	53.61	33,914	23.85	39,807	27.67	28,695	15.40
Private: PIE	29,825	26.44	22,547	15.85	32,592	22.66	22,557	12.11
Private: Cogeneration	6,078	5.39	6,117	4.30	5,975	4.15	5,627	3.02
Private: Self-consumption	19,909	17.65	2,712	1.91	652	0.45	345	0.19
Private: Market	3,111	2.76	1,414	0.99	463	0.32	140	0.08
Private: SLP	1,187	1.05	1,120	0.79	126	0.09	4	0.00
Private: CLSB	356	0.32	4	0.00	1	0.00	22	0.01

As shown in Tables 8 and 9, prioritizing state-owned generation would increase annual CO_2 emissions by 26% or 29.4 Mton (Scenario 1), 28% or 31.1 Mton (Scenario 2), or else 65% or 73.5 Mton (Scenario 3).

5.4.2 SO_2 Emissions

Tables 10 and 11 show the annual SO_2 emissions for the four scenarios per fuel and per generator owner and contract type, respectively.

Table 10. Annual SO_2 Emissions for Each Generation Technology

SO_2 emissions (kton)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total	**1487**	**[%]**	**3760**	**[%]**	**3759**	**[%]**	**5297**	**[%]**
Natural gas	198	13.32	209	5.56	213	5.68	255	4.82
Fuel oil	214	14.41	1979	52.63	1962	52.20	2592	48.92
Diesel	2	0.14	1	0.03	1	0.03	1	0.02
Coal	1067	71.76	1571	41.77	1582	42.09	2449	46.23
Coke	5	0.36	0	0.00	0	0.00	0	0.00

Table 11. Annual SO_2 Emissions for Each Generator Owner and Contract Type

SO_2 emissions (kton)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total	**1,487**	**[%]**	**3,760**	**[%]**	**3,759**	**[%]**	**5,297**	**[%]**
Public agent total	1,290	86.76	3,620	96.26	3,604	95.86	5,170	97.59
CFE: Market	90	6.07	1,812	48.19	1,792	47.67	2,465	46.53
CFE: CLSB	1,174	78.98	1,782	47.40	1,786	47.52	2,677	50.53
CFE: Cogeneration	6	0.39	6	0.15	6	0.15	7	0.12
PEMEX: Cogeneration	20	1.32	19	0.52	19	0.51	22	0.41
Private agent total	197	13.24	141	3.74	156	4.14	128	2.41
Private: PIE	76	5.12	58	1.53	83	2.21	58	1.09
Private: Cogeneration	70	4.73	70	1.87	70	1.85	69	1.30
Private: Self-consumption	38	2.59	7	0.17	1	0.03	1	0.01
Private: Market	8	0.53	4	0.10	1	0.03	0	0.01
Private: SLP	3	0.20	3	0.08	0	0.01	0	0.00
Private: CLSB	1	0.06	0	0.00	0	0.00	0	0.00

As shown in Tables 10 and 11, prioritizing state-owned generation would increase annual SO_2 emissions by 153% or 2.27 Mton (Scenarios 1 and 2), or else 256% or 3.81 Mton (Scenario 3).

5.4.3 *NO_X Emissions*

Table 11 and Table 12 show the annual NO_X emissions for the four scenarios per fuel and per generator owner and contract type, respectively.

Table 12. Annual NO_X Emissions for Each Generation Technology

NO_x emissions (kton)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total	**1,408**	**[%]**	**2,066**	**[%]**	**2,084**	**[%]**	**2,713**	**[%]**
Natural gas	952	67.6	1,005	48.6	1,026	49.2	1,227	45.2
Fuel oil	64	4.5	591	28.6	586	28.1	774	28.5
Diesel	59	4.2	36	1.7	35	1.7	36	1.3
Coal	294	20.9	433	21.0	437	21.0	676	24.9
Coke	38	2.7	1	0.1	1	0.1	1	0.0

Table 13. Annual NO_x Emissions for Each Generator Owner and Contract Type

NO_x emissions (kton)	Reference		Scenario 1		Scenario 2		Scenario 3	
Total	**1,408**	**[%]**	**2,066**	**[%]**	**2,084**	**[%]**	**2,713**	**[%]**
Public agent total	722	51.24	1,650	79.85	1,595	76.54	2,361	86.99
CFE: Market	165	11.69	817	39.54	794	38.08	1,197	44.13
CFE: CLSB	435	30.90	711	34.43	681	32.69	1,028	37.88
CFE: Cogeneration	28	1.97	28	1.34	28	1.33	31	1.16
PEMEX: Cogeneration	94	6.68	94	4.53	93	4.44	104	3.83
Private agent total	687	48.76	416	20.15	489	23.46	353	13.01
Private: PIE	366	26.01	277	13.40	400	19.21	277	10.21
Private: Cogeneration	76	5.43	77	3.72	75	3.61	71	2.61
Private: Self-consumption	187	13.26	31	1.52	6	0.30	3	0.11
Private: Market	38	2.71	17	0.84	6	0.27	2	0.06
Private: SLP	15	1.04	14	0.67	2	0.07	0	0.00
Private: CLSB	4	0.31	0	0.00	0	0.00	0	0.01

As shown in Tables 12 and 13, prioritizing state-owned generation would increase annual NO_x emissions by 47% or 658 kton (Scenario 1), 48% or 676 kton (Scenario 2), or else 93% or 1,305 kton (Scenario 3).

6 Conclusions

Based on the detailed power system modeling performed in this study, amendments, published and under discussion, to Mexico's electricity legal framework and market rules seeking to benefit power generation from the state-owned utility CFE would have the following impact on the Mexican power system:

- The proposed/approved amendments to Mexico's electricity unit commitment and dispatch rules will likely increase variable electricity production costs under all scenarios. The increase could be added to electricity subsidies or passed onto consumers.
- Emissions of CO_2, SO_2, and NO_X significantly increase under all scenarios.
- Wind and solar curtailment under the Reference Scenario is 0.32 TWh, which is the equivalent to 0.8% of available wind and solar generation. While this figure remains the same under Scenario 1, it increases by 154% under Scenario 2. Under Scenario 3, wind and solar curtailment jumps more than 114.4x over the Reference Scenario and is the equivalent of 90.93% of all wind and solar available generation in Mexico.

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Appendix A. Comparison of SAInt's and CENACE's Average Weekly Dispatch for Each Generation Technology for Four Months of the Year.

The following figures show the average weekly dispatch per generation technology for four different months (January, April, July, and October) from SAInt's production cost modeling outputs compared to the actual dispatch reported by CENACE.

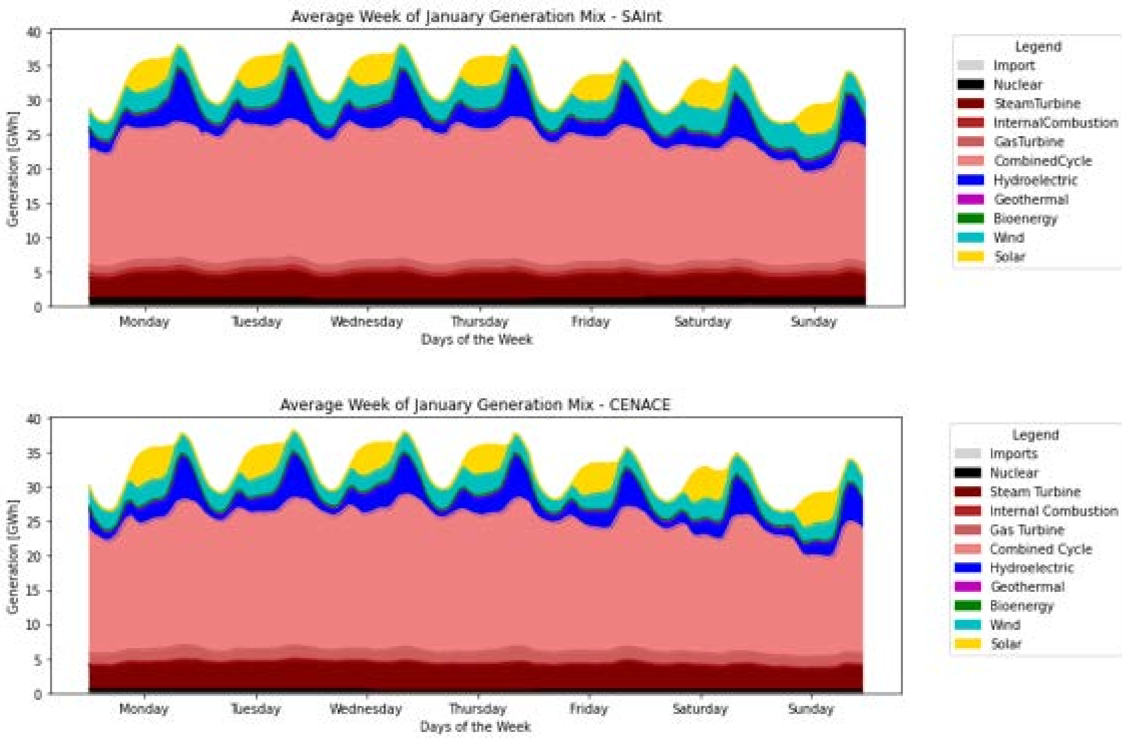

Figure A-1. Average Weekly Dispatch Per Generation Technology for January

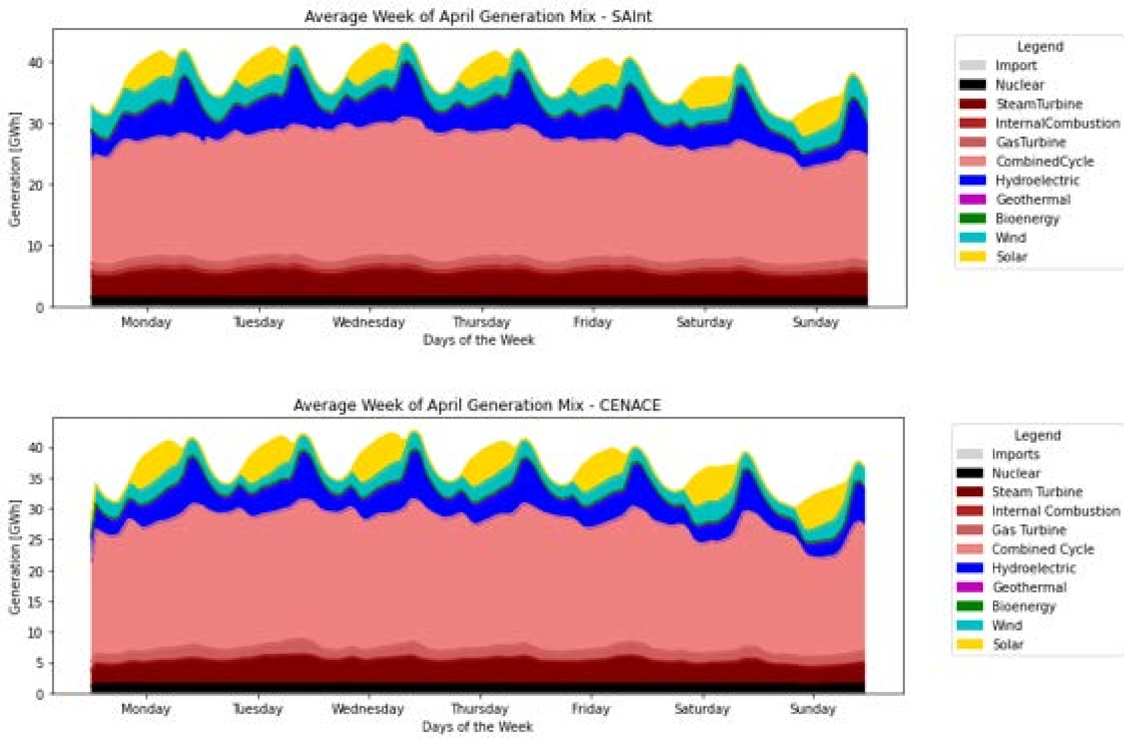

Figure A-2. Average Weekly Dispatch Per Generation Technology for April

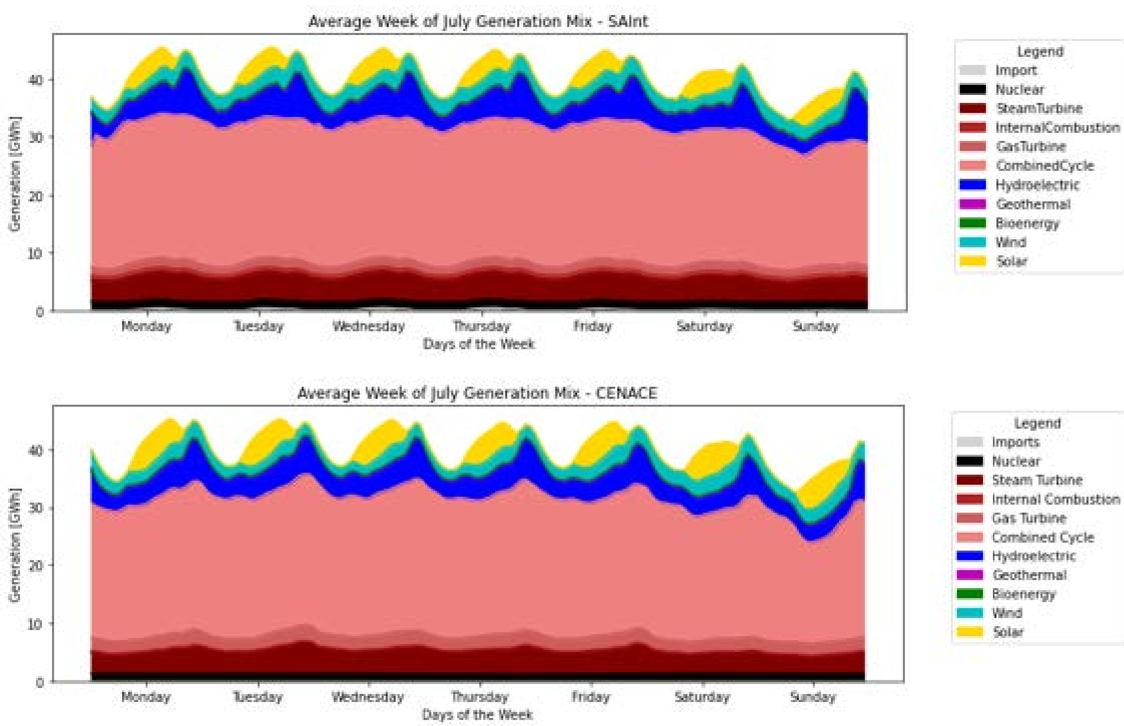

Figure A-3. Average Weekly Dispatch Per Generation Technology for July

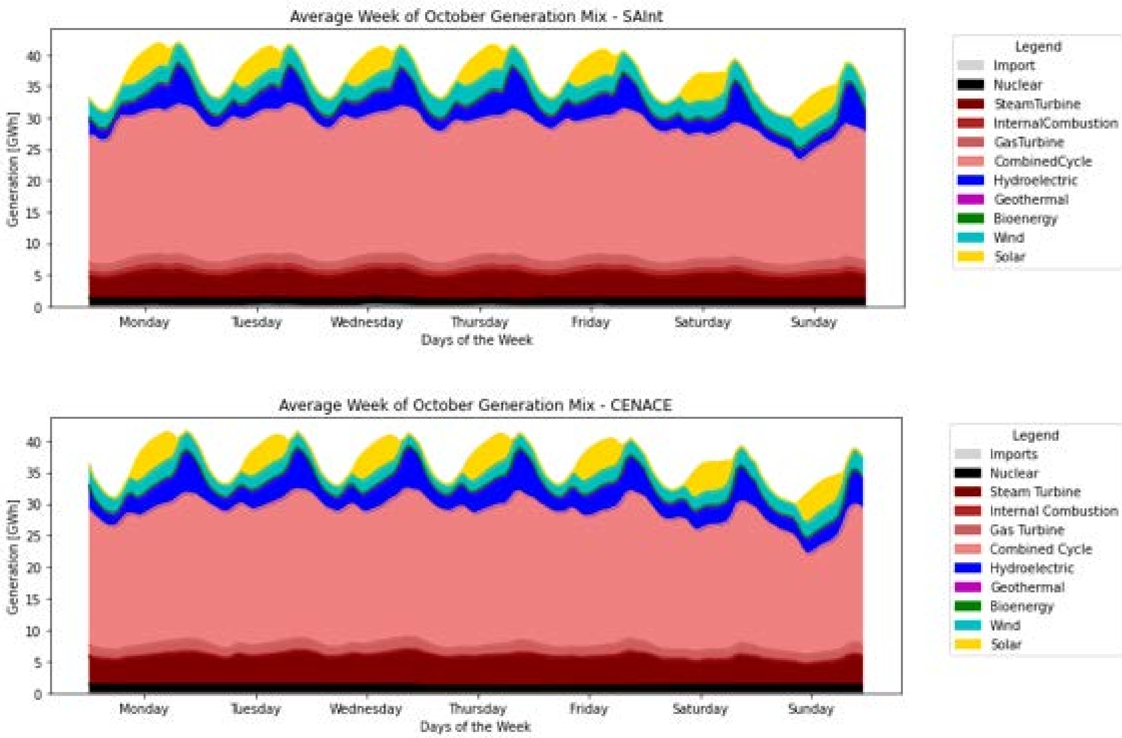

Figure A-4. Average Weekly Dispatch Per Generation Technology for October

Appendix B. Annual and Monthly Generation Mix for Each Technology and Annual Generation Mix for Each Generator Owner and Contract Type

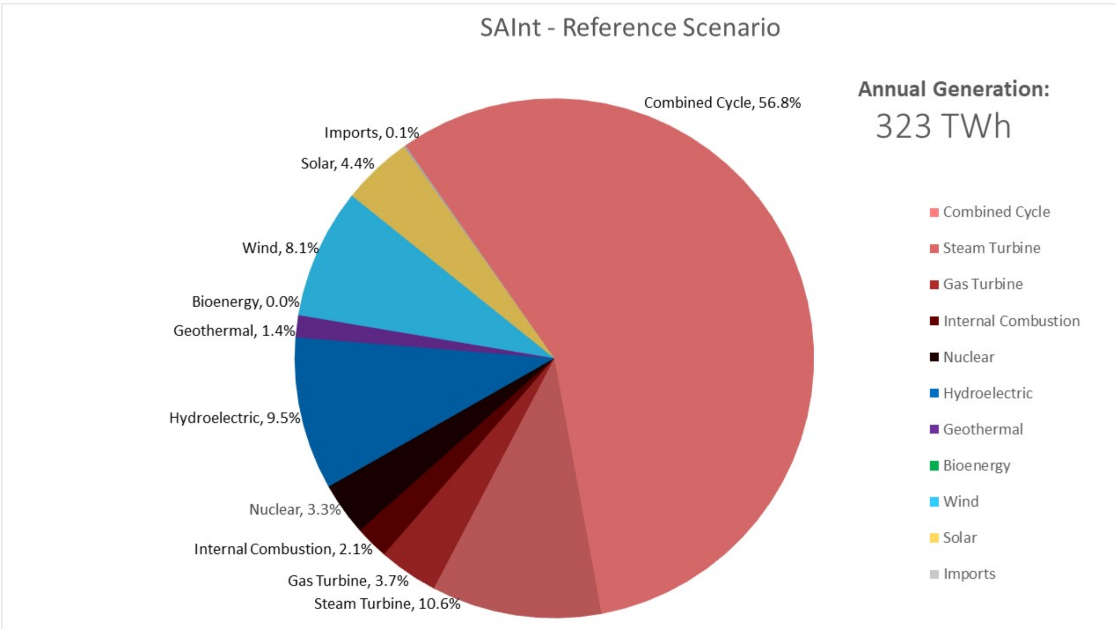

Figure B-1. Annual generation mix for each generation technology: Reference Scenario

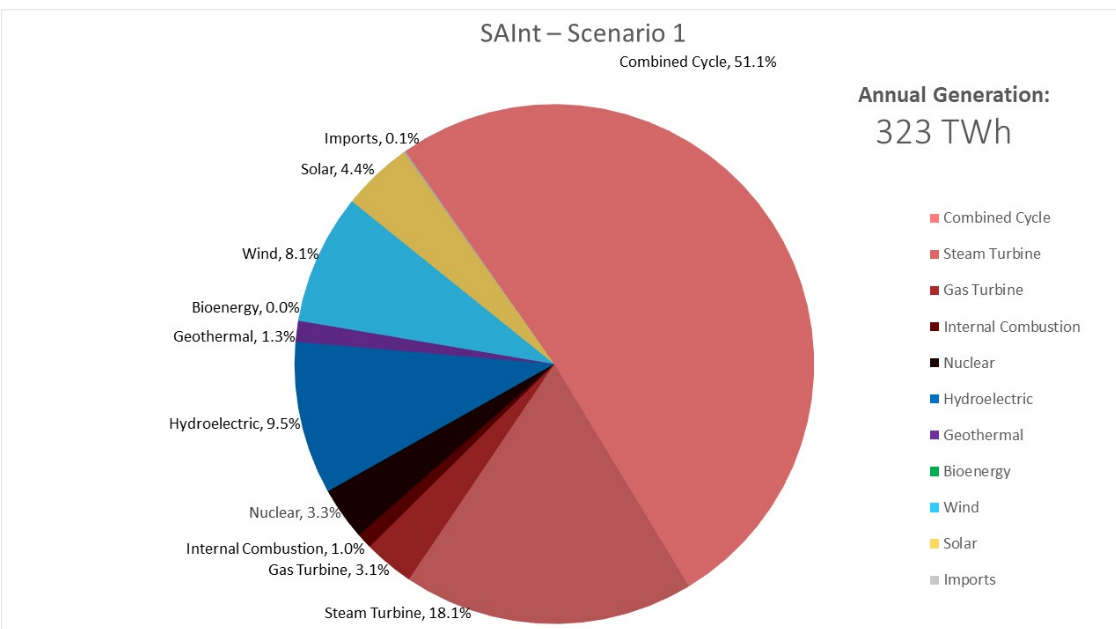

Figure B-2. Annual generation mix for each generation technology: Scenario 1

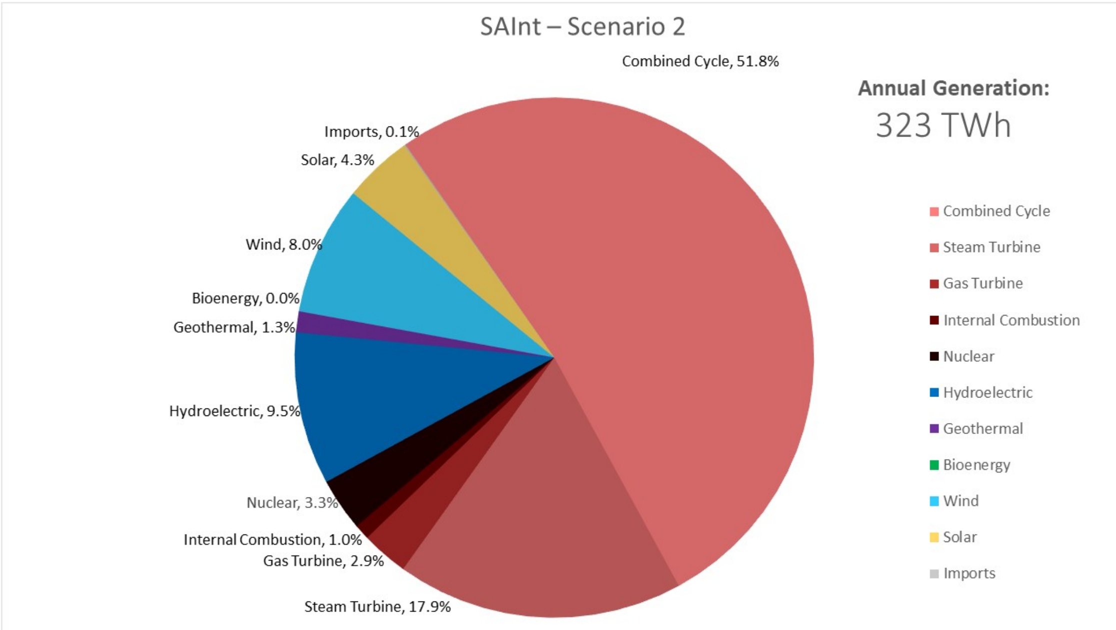

Figure B-3. Annual generation mix for each generation technology: Scenario 2

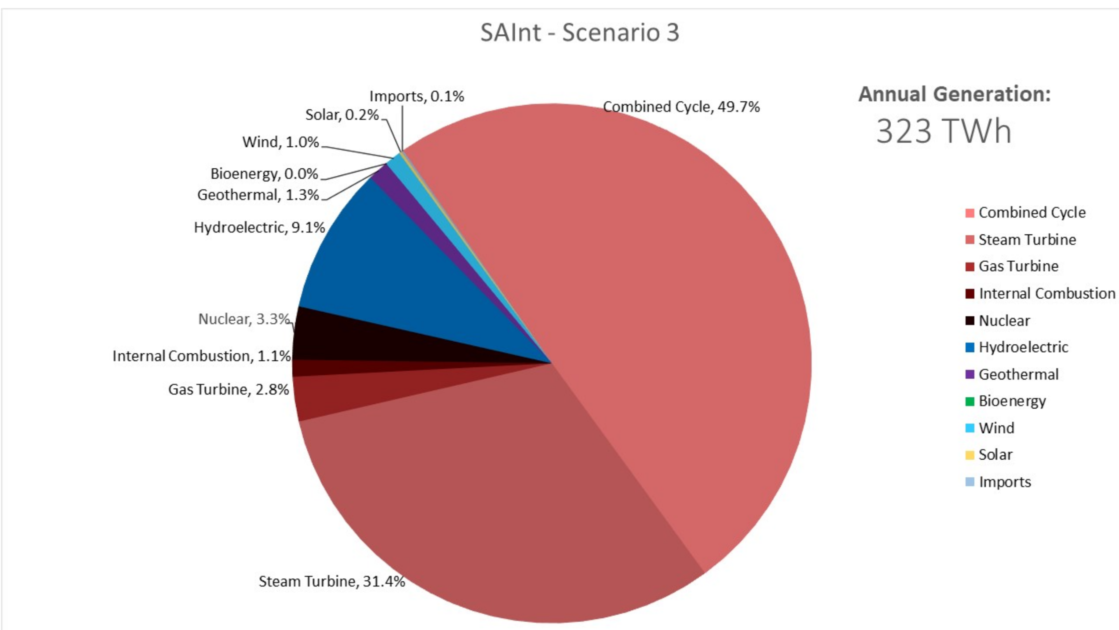

Figure B-4. Annual generation mix for each generation technology: Scenario 3

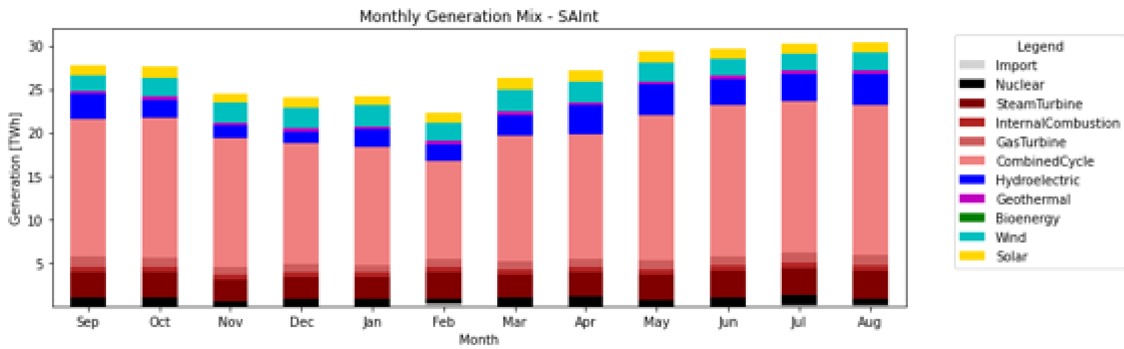

Figure B-5. Monthly generation mix for each generation technology: Reference Scenario

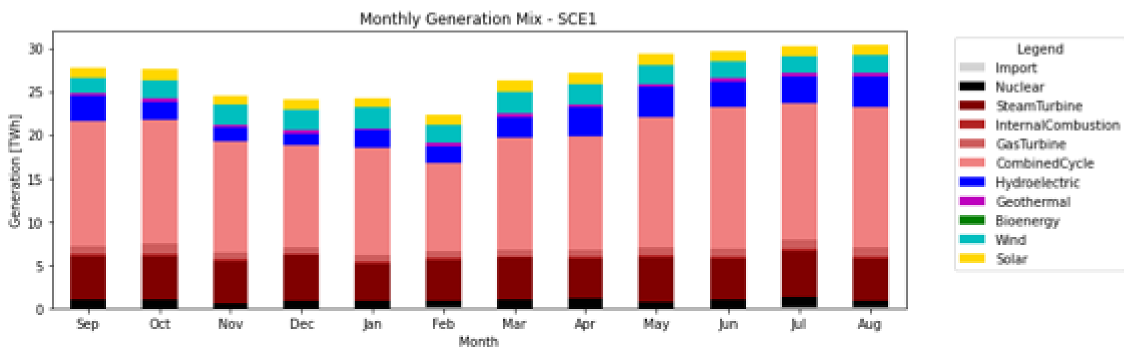

Figure B-6. Monthly generation mix for each generation technology: Scenario 1

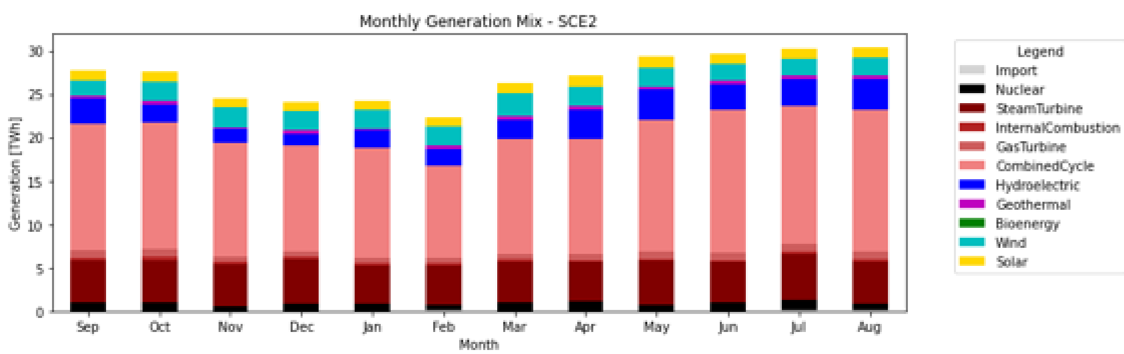

Figure B-7. Monthly generation mix for each generation technology: Scenario 2

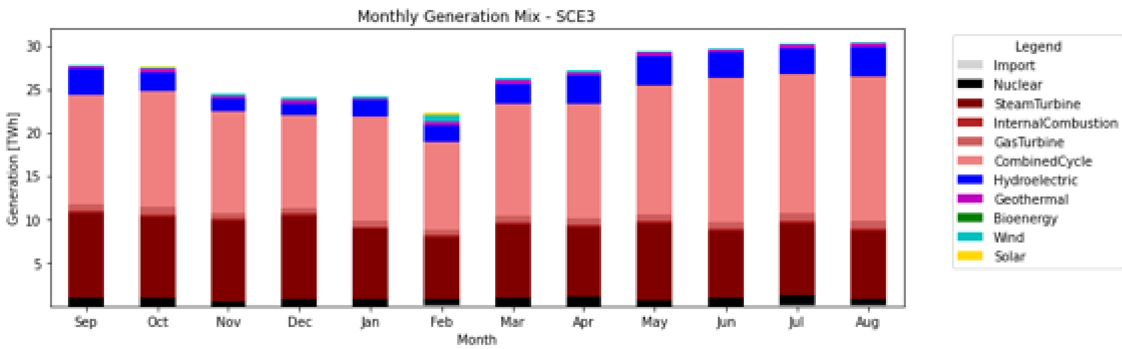

Figure B-8. Monthly generation mix for each generation technology: Scenario 3

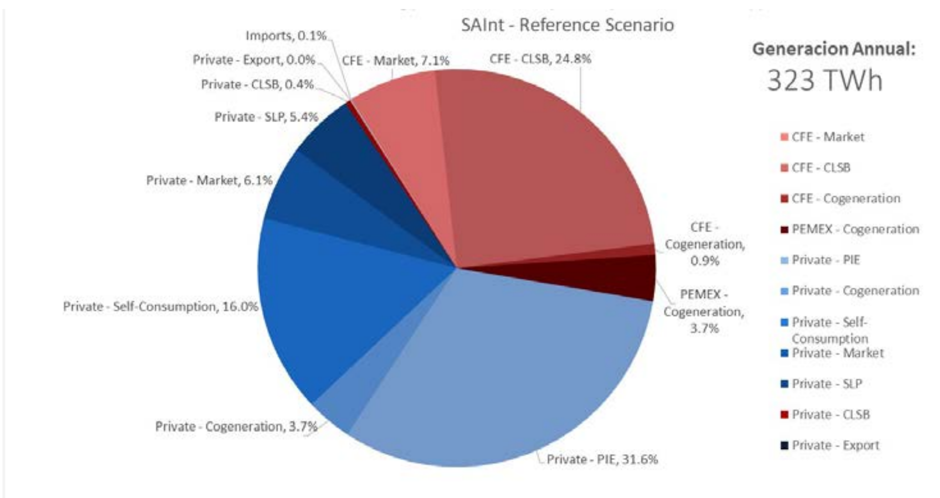

Figure B-9. Annual generation mix for each generator owner and contract: Reference Scenario

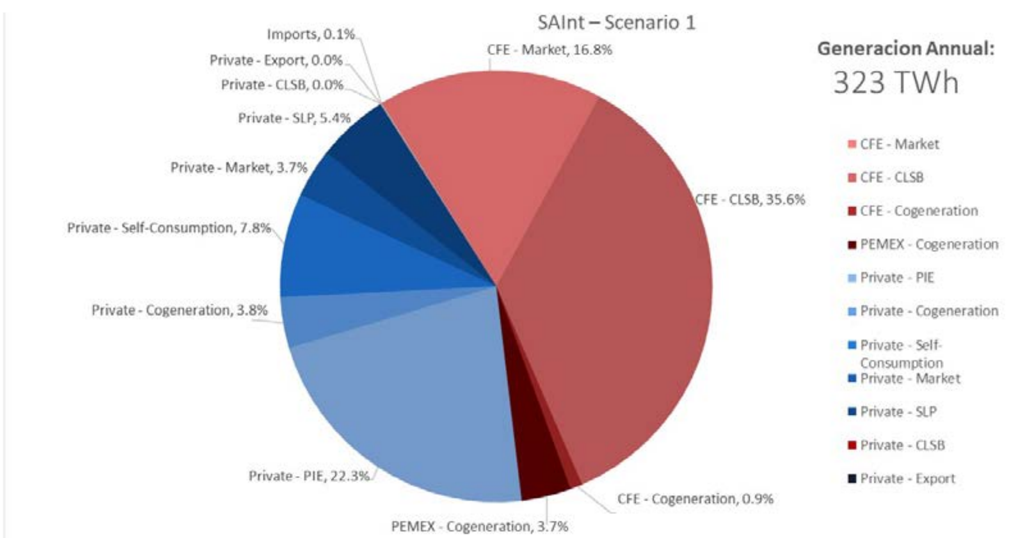

Figure B-10. Annual generation mix for each generator owner and contract: Scenario 1

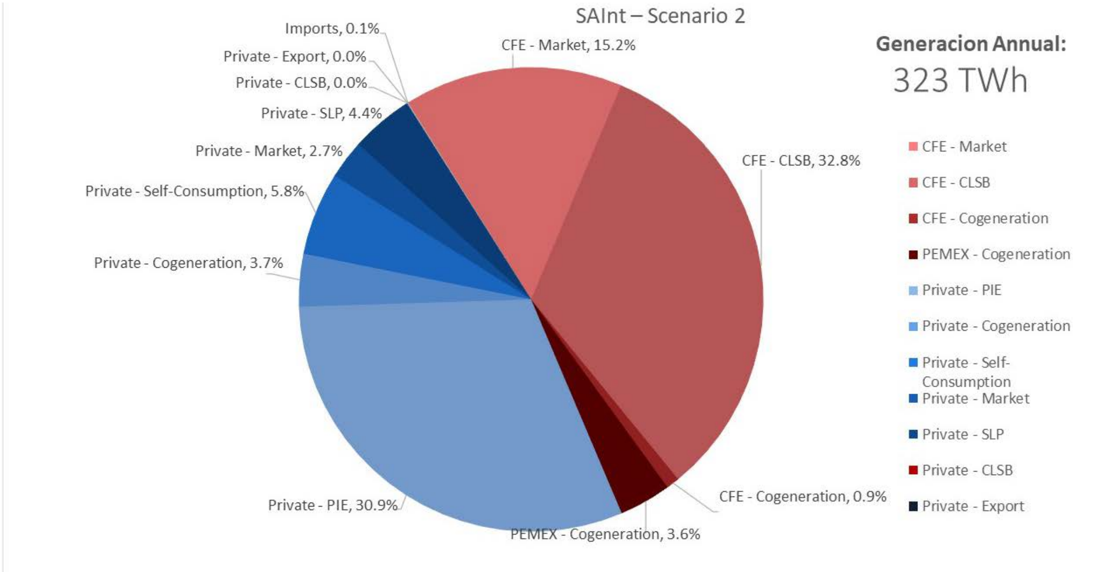

Figure B-11. Annual generation mix for each generator owner and contract: Scenario 2

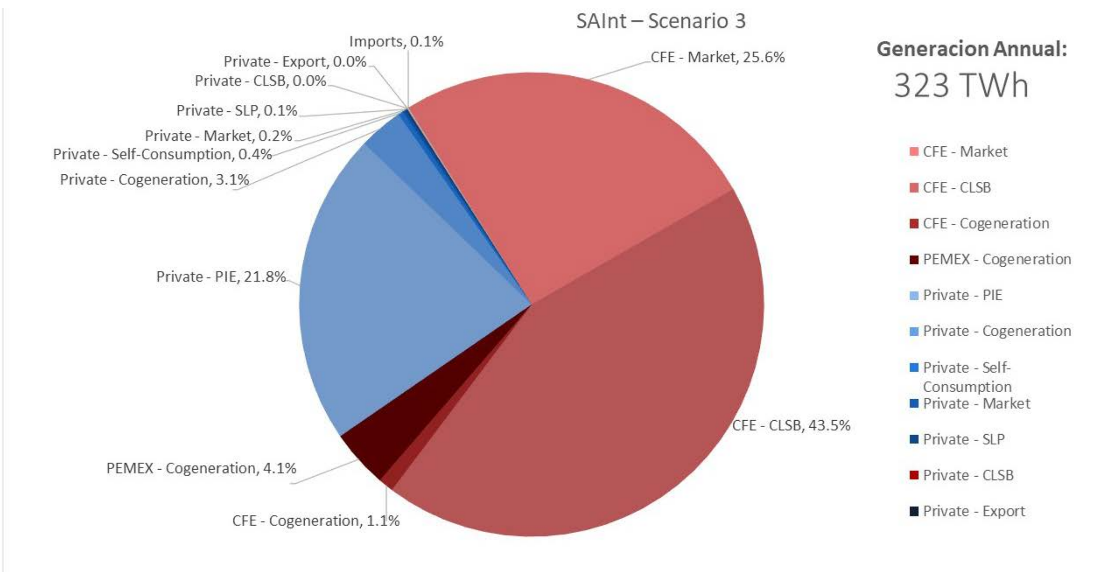

Figure B-12. Annual generation mix for each generator owner and contract: Scenario 3

The following figures show the average weekly dispatch for each generation technology for the four scenarios.

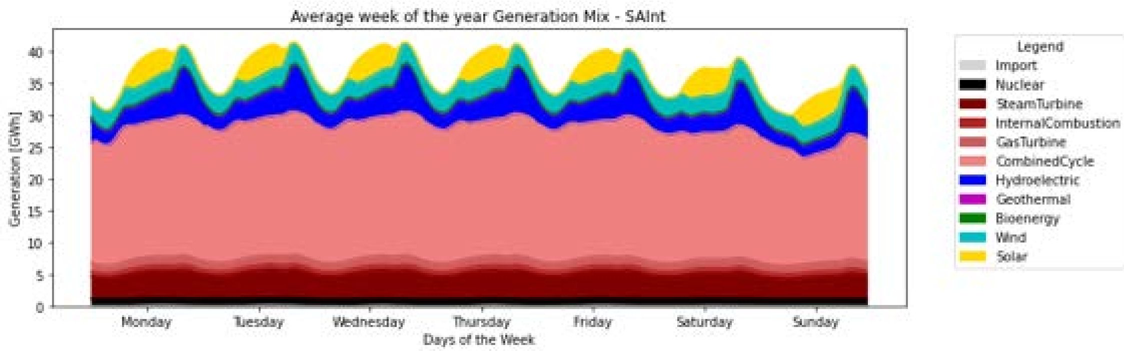

Figure B-13. Average weekly dispatch for each generation technology: Reference Scenario

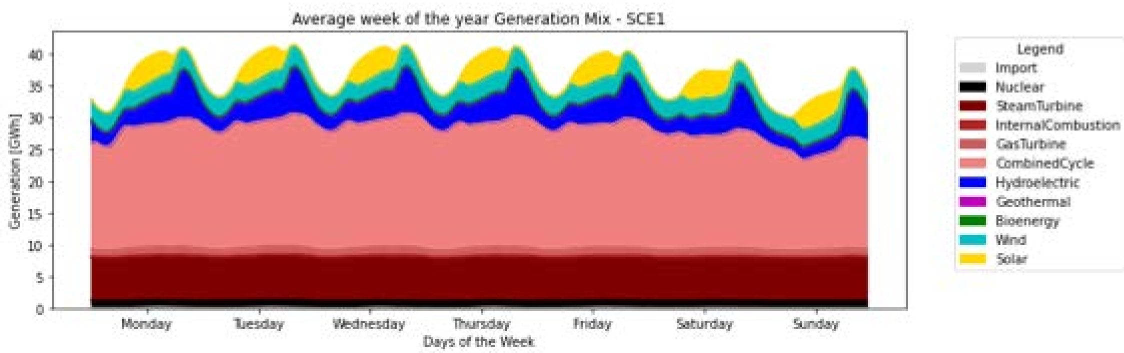

Figure B-14. Average weekly dispatch for each generation technology: Scenario 1

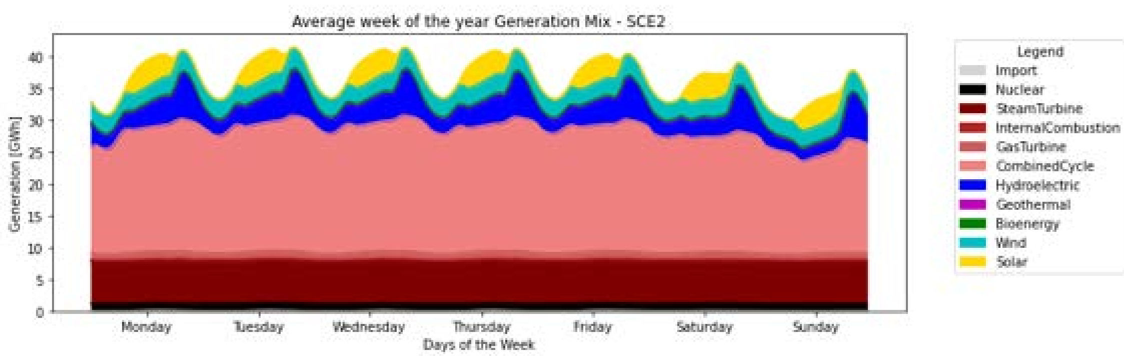

Figure B-15. Average weekly dispatch for each generation technology: Scenario 2

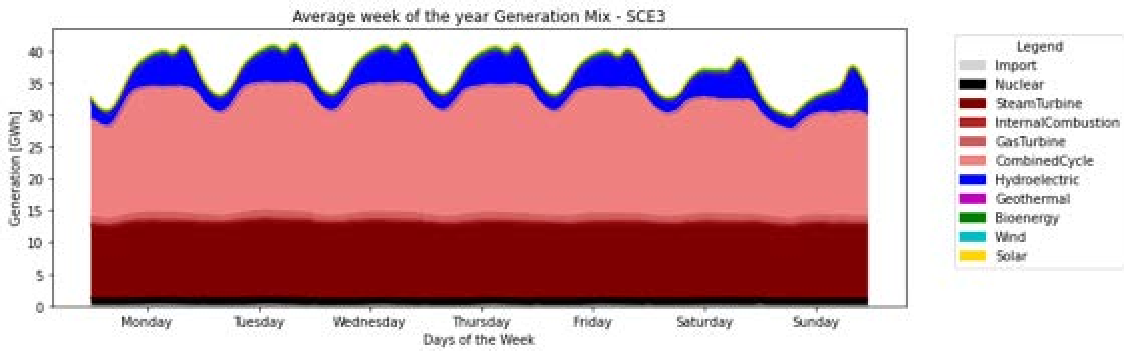

Figure B-16. Average weekly dispatch for each generation technology: Scenario 3

The following figures show the average weekly dispatch for each generation technology for the month of January for the four scenarios.

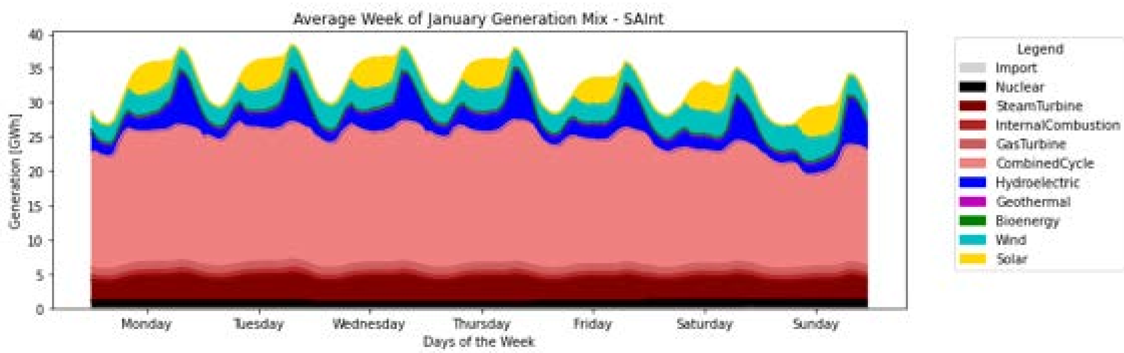

Figure B-17. Average weekly dispatch for each generation technology in January: Reference Scenario

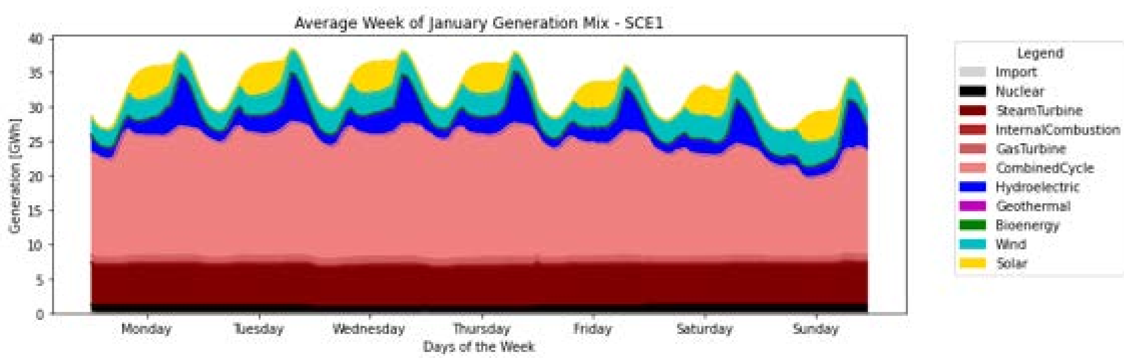

Figure B-18. Average weekly dispatch for each generation technology in January: Scenario 1

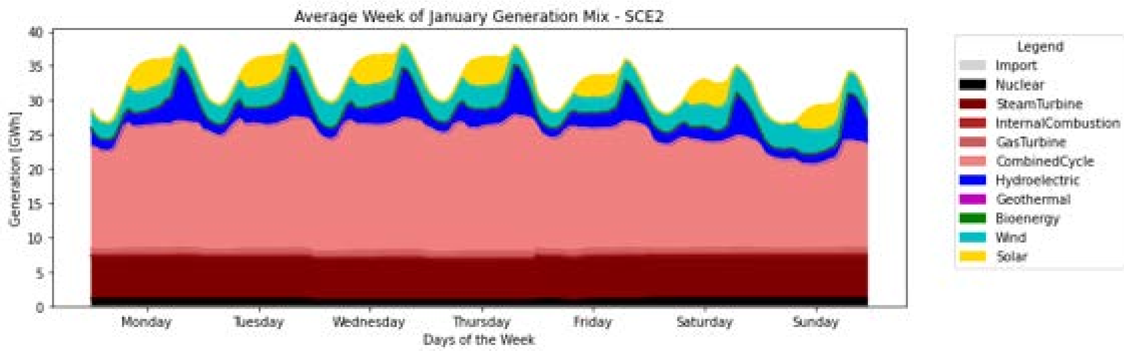

Figure B-19. Average weekly dispatch for each generation technology in January: Scenario 2

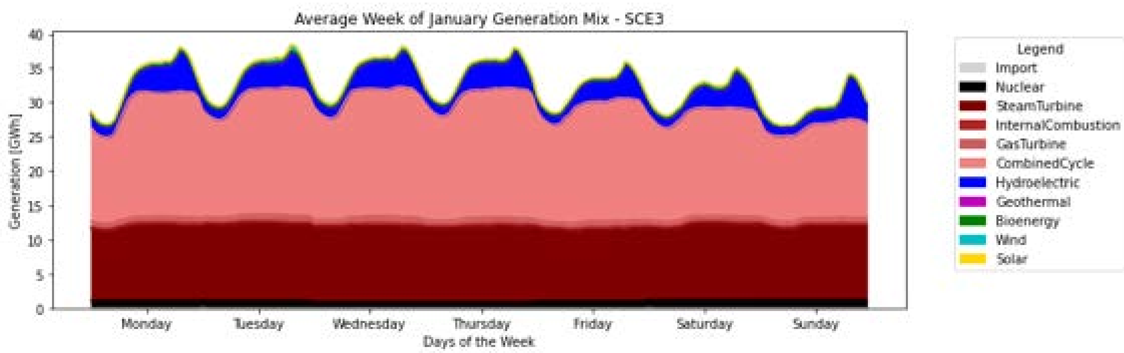

Figure B-20. Average weekly dispatch for each generation technology in January: Scenario 3

The following figures show the average weekly dispatch for each generation technology for the month of April for the four scenarios.

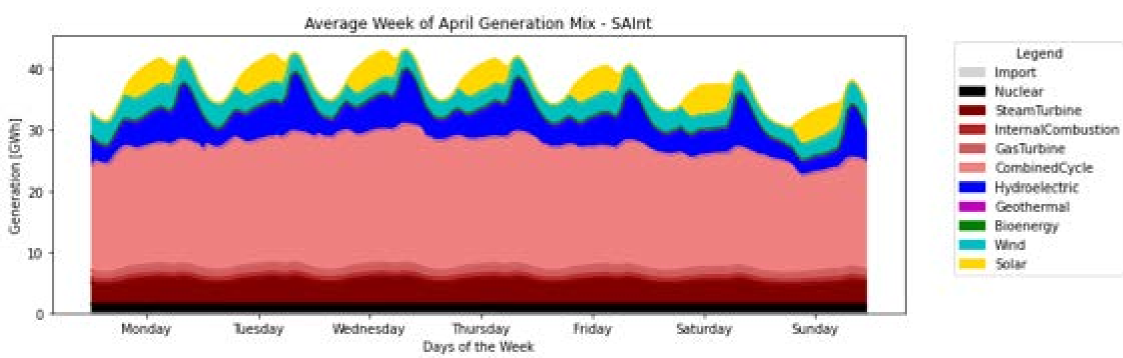

Figure B-21. Average weekly dispatch for each generation technology in April: Reference Scenario

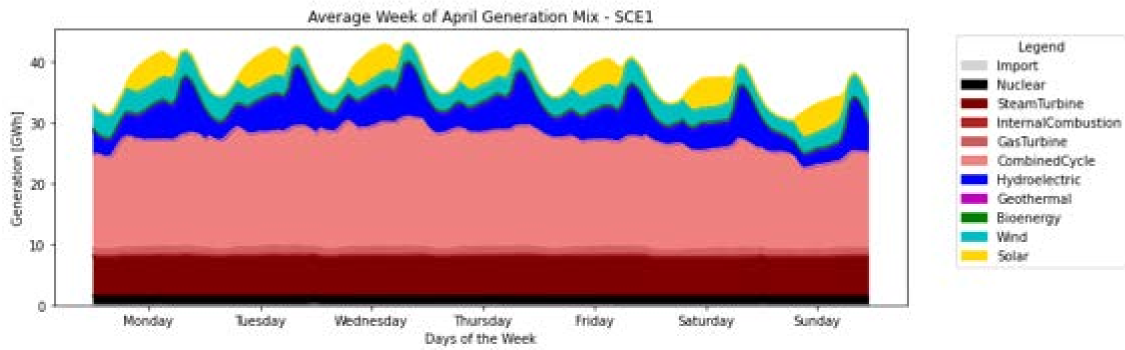

Figure B-22. Average weekly dispatch for each generation technology in April: Scenario 1

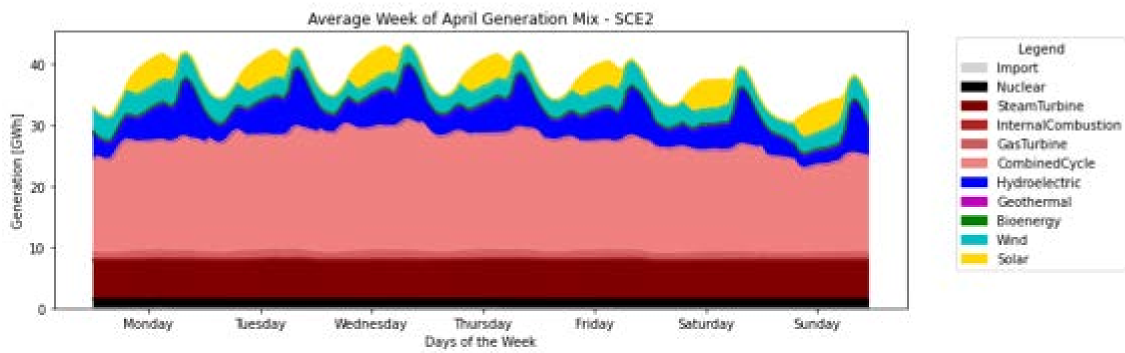

Figure B-23. Average weekly dispatch for each generation technology in April: Scenario 2

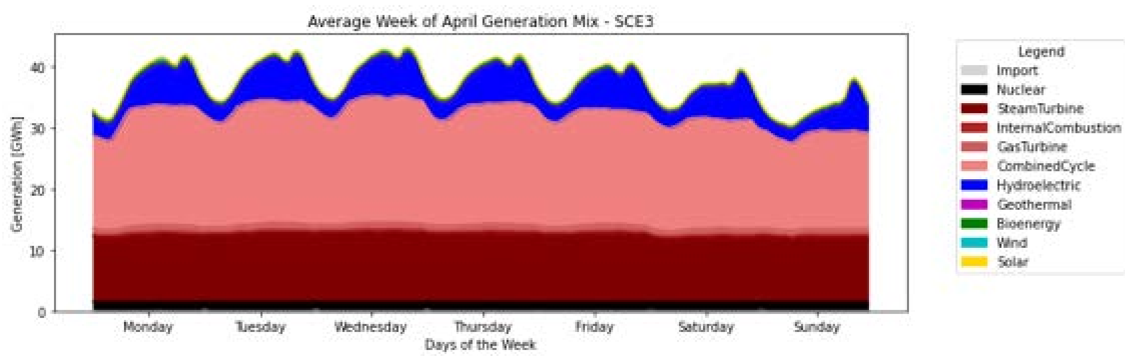

Figure B-24. Average weekly dispatch for each generation technology in April: Scenario 3

The following figures show the average weekly dispatch for each generation technology for the month of July for the four scenarios.

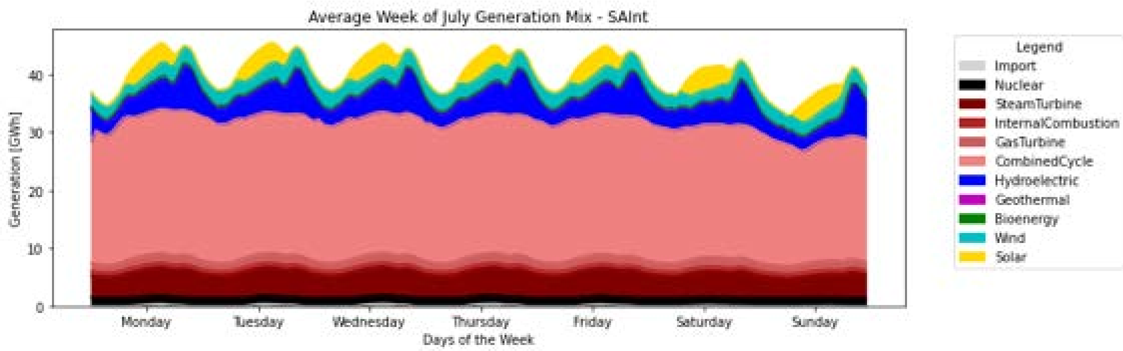

Figure B-25. Average weekly dispatch for each generation technology in July: Reference Scenario

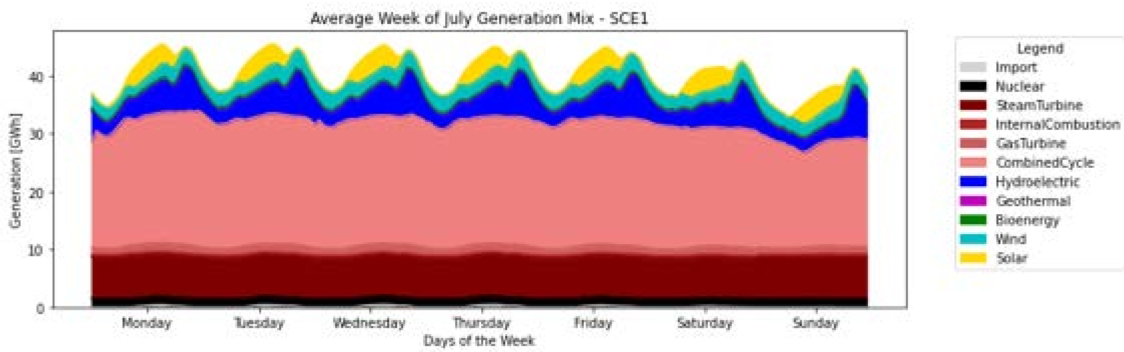

Figure B-26. Average weekly dispatch for each generation technology in July: Scenario 1

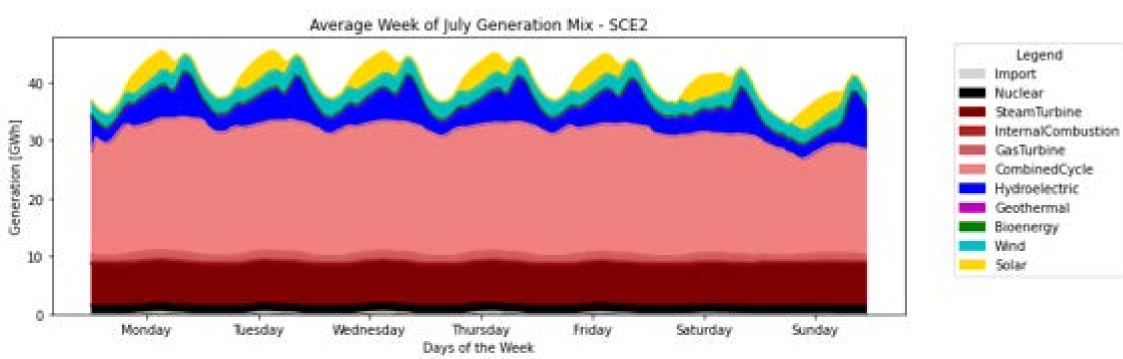

Figure B-27. Average weekly dispatch for each generation technology in July: Scenario 2

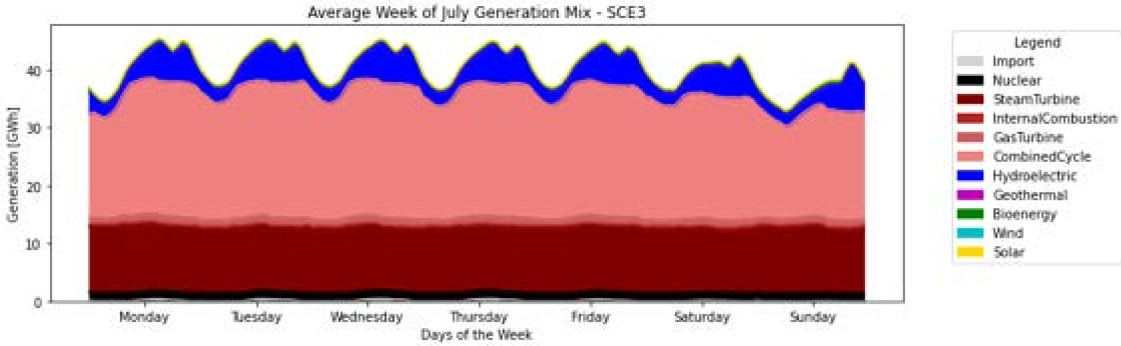

Figure B-28. Average weekly dispatch for each generation technology in July: Scenario 3

The following figures show the average weekly dispatch for each generation technology for the month of October for the four scenarios.

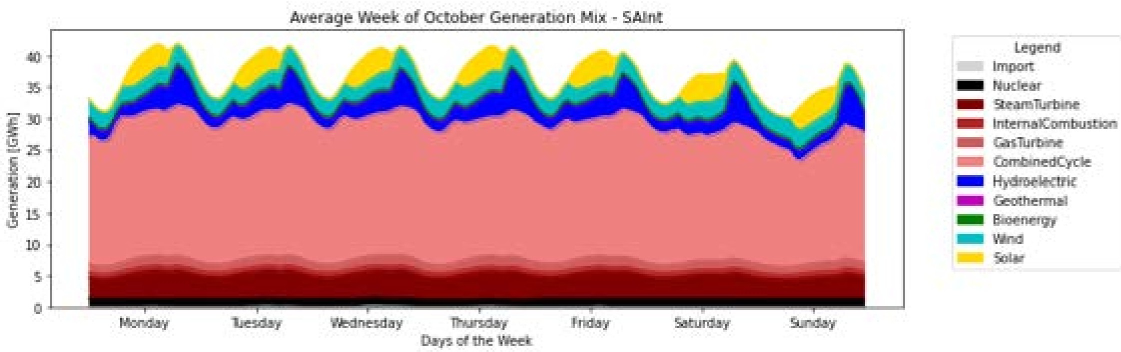

Figure B-29. Average weekly dispatch for each generation technology in October: Reference Scenario

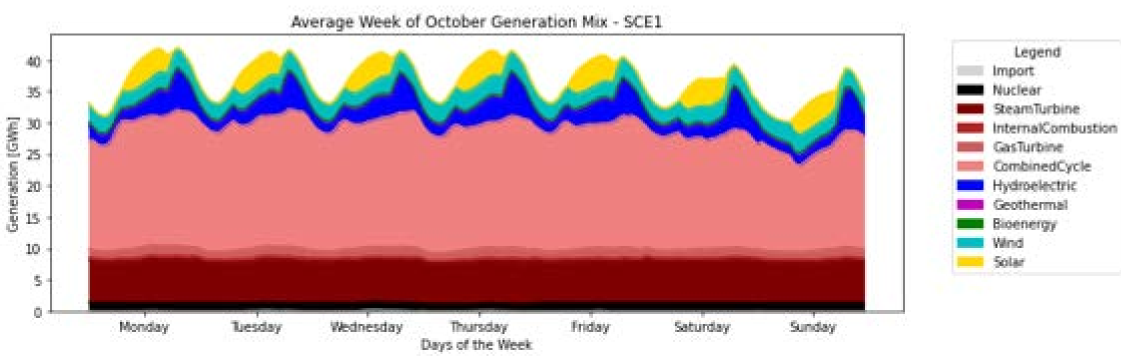

Figure B-30. Average weekly dispatch for each generation technology in October: Scenario 1

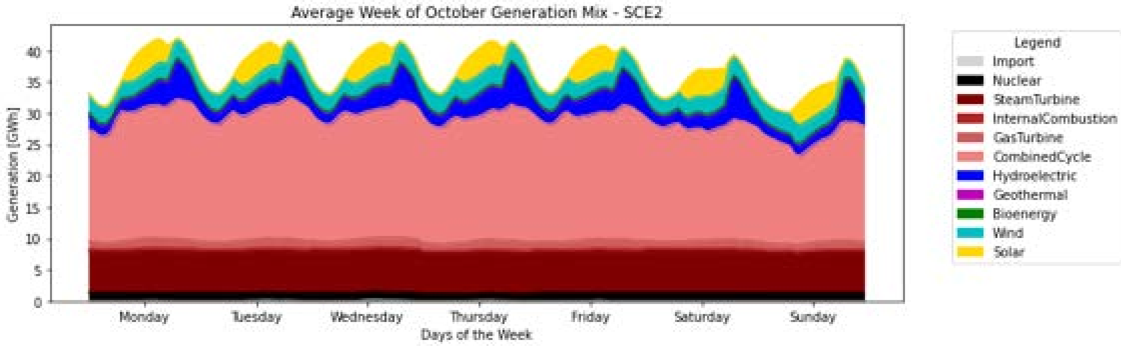

Figure B-31. Average weekly dispatch for each generation technology in October: Scenario 2

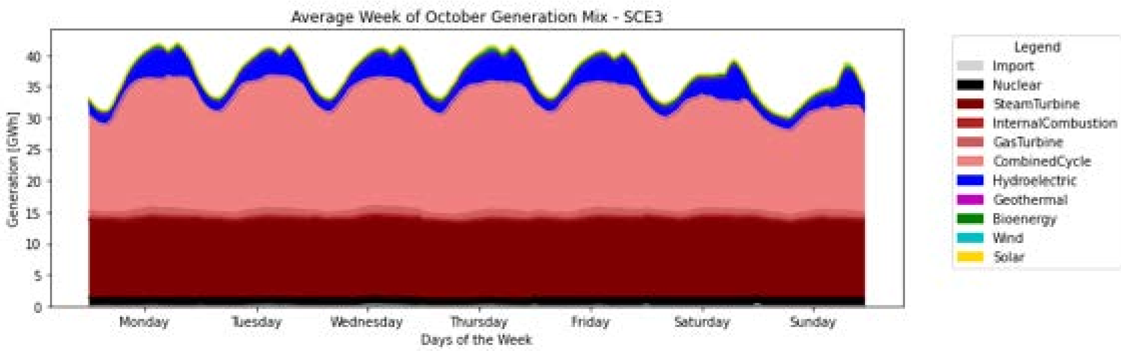

Figure B-32. Average weekly dispatch for each generation technology in October: Scenario 3