INTERMITTENT RESOURCES ASSESSMENT ON POWER GRID UNDER AN HOURLY SCALED BOTTOM-UP MODEL

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ABSTRACT

This study aims to model and examine the Turkish electricity sector by using TIMES modeling framework. It attempts to investigate the decisions of the proposed model under various scenarios.

As the energy need grows globally, Turkey’s need is also rising each year with the increase in population and industrialization. Properly planned investment decisions are needed to satisfy this need in future periods without facing increased costs or system instabilities.

The current electricity sector is modeled in the reference scenario. Other scenarios for regional investment options for wind and solar power plants have been carried out. The policies about government incentives are applied in other scenarios.

In the end, a system-wide analysis for cost and investment decisions is done. The results of the proposed scenarios are compared with the reference scenario. The potential pathways to the future electricity sector are underlined.

Keywords: Energy, Electricity, Bottom-up model, TIMES, Linear Programming, Investment Decisions, Reference Energy System, Emission Reduction, Scenario Analysis, Minimum Cost Analysis

SAATLİK ÖLÇEKLENDİRİLMİŞ TEMELDEN-YUKARI MODEL ALTINDA GÜÇ ŞEBEKESİ ÜZERİNDE ARALIKLI KAYNAK DEĞERLENDİRMESİ

ÖZET

Bu çalışma, TIMES modelleme çerçevesini kullanarak Türkiye elektrik sektörünü modellemeyi ve incelemeyi amaçlamaktadır. Önerilen modelin kararlarını çeşitli senaryolar altında incelemeye çalışır.

Dünya genelinde enerji ihtiyacı arttıkça, nüfus artışı ve sanayileşme ile Türkiye'nin ihtiyacı da her geçen yıl artmaktadır. Bu ihtiyacı gelecek dönemlerde aşırı artan maliyetler veya sistem kararsızlıkları ile karşılaşmadan karşılamak için doğru planlanmış yatırım kararlarına ihtiyaç vardır.

Mevcut elektrik sektörü referans senaryoda modellenmiştir. Rüzgar ve güneş santralleri ile ilgili bölgesel yatırım seçenekleri için farklı senaryolar uygulanmıştır. Devlet teşvikleri ile ilgili politikalar diğer senaryolarda uygulanmaktadır.

Sonuç olarak, maliyet ve yatırım kararları için sistem çapında bir analiz yapılmaktadır. Önerilen senaryoların sonuçları referans senaryo ile karşılaştırılmaktadır. Gelecekteki elektrik sektörüne yönelik potansiyel yolların altı çizilmiştir.

Anahtar Kelimeler: Enerji, Elektrik, Temelden-yukarı model, TIMES, Doğrusal Programlama, Yatırım Kararları, Referans Enerji Sistemi, Emisyon Azaltma, Senaryo Analizi, Minimum Maliyet Analizi

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Nurdan Yağmur BULUT

To my family and friends…

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LIST OF ABBREVIATIONS

CF	Capacity Factor
IEA	International Energy Agency
GHG	Greenhouse gases
GW	Gigawatt
Mton	Metric ton
MUSD	Million United States Dolar
PJ	Peta Joule
TIMES	The Integrated MARKAL-Efom System
TWh	Terawatt hour

CHAPTER 1

1. INTRODUCTION

1.1 Worldwide Electricity Production and Consumption

Growing industrialization and urbanization lead to economic developments in many countries. An increase in demand for energy brings the need for new investment plans. Especially in the electricity sector, meticulously planned investment decisions are significant for producers and consumers.

Satisfying the energy demand is getting hard not only because of the increase but also because of the economic and social requirements. The diminishing of a specific energy source, environmental concerns, or budgets can be examples of these requirements. Therefore, the ability to shift to renewable energy sources becomes crucial. Also, implementing new efficient technologies into the system can help to satisfy various requirements.

International Energy Agency (IEA)'s The Stated Policies scenario (STEPS) where assumes a decline in electricity demand in 2020 as almost 500 terawatt-hours (TWh) worldwide. IEA expects that the demand will return to its pre-Covid levels by 2021. Global electricity demand will be over 26,000 TWh by 2025. After 2025, steady growth in global electricity demand is expected until 2030, when it reaches approximately 29,000 TWh [7]. The real demands for 2018, 2019, and 2020, with the expected demands until 2030, can be seen in Figure 1.1.

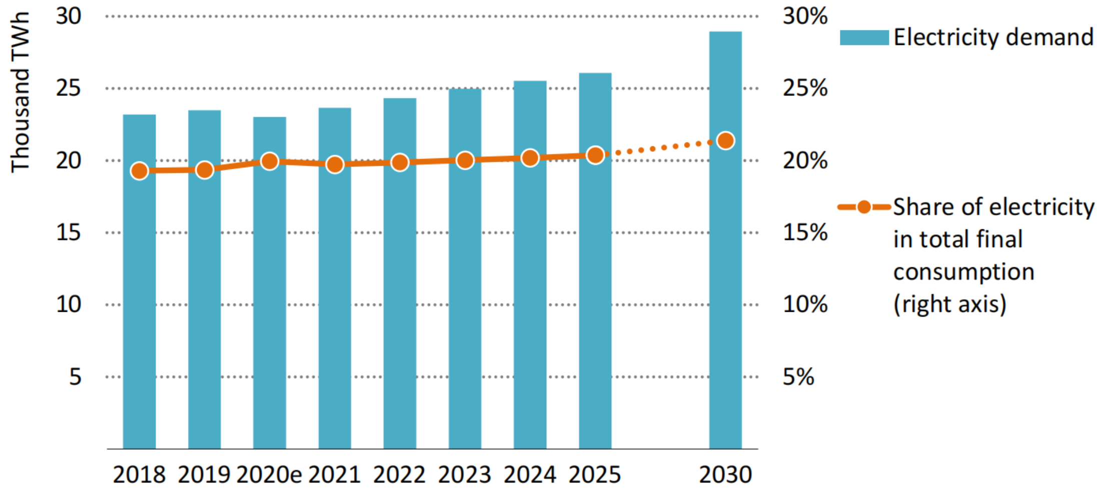

Figure 1.1 Global electricity demand and share in total final consumption in IEA's STEPS, 2018 – 2030 [7]

STEPS predicts that renewables and nuclear power will overtake the electricity generation from coal while providing almost half of global electricity supply by 2030. By the aid of decreasing costs to invest and operate in solar and wind power, more countries aim to increase their renewable shares in electricity generation. Expected renewable and nuclear shares can be seen in Figure 1.2. While hydropower, solar PV, and wind have the greatest shares in renewable energy mix, other types of renewables such as geothermal, bioenergy, concentrating solar, are being deployed until 2030 to help the diversity of electricity production [7].

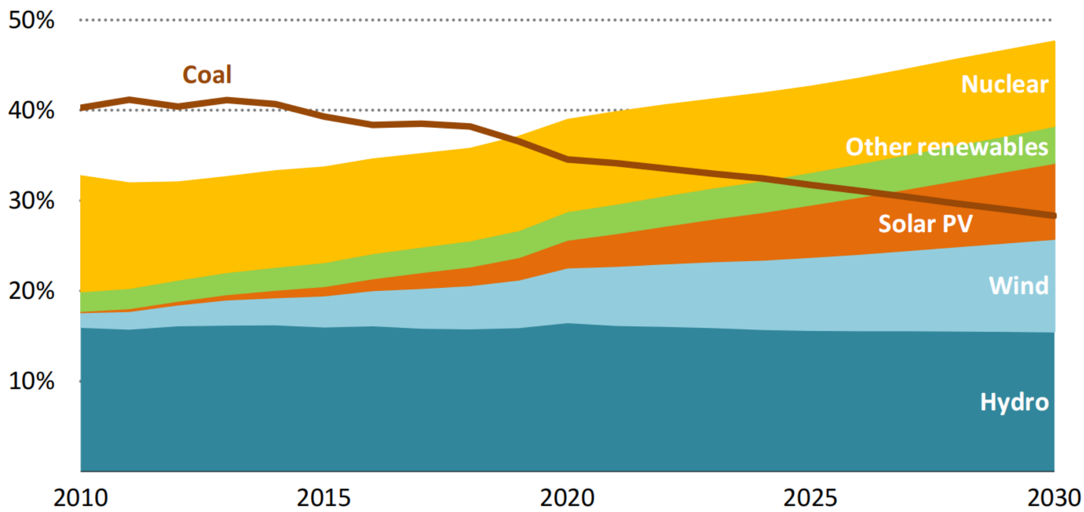

Figure 1.2 Global electricity supply shares of renewable, nuclear and coal in IEA's STEPS [7]

Turkey is one of the countries whose energy consumption raises each year. It is expected that this raise will continue in the future. According to Republic of Turkey Ministry of Energy and Natural Resources' Electricity Demand Projection Report, the annual electricity consumption is expected to be 370 TWh in 2025 and 591 TWh in 2040. [5]

Turkey needs to create solid policies to increase the electricity generation while concerning environmental issues and transmission grid structure. Depending on fossil fuels is not an option while energy production emits the highest greenhouse gases. A meticulously planned shift to renewable energy sources including other energy sources for diversity can help in this sense. Rapid shifting from non-renewable energy sources to renewables ones can cause an instability in electricity grid while increasing the costs of system. Therefore, further research is needed to construct solid policies.

1.2 Purpose of This Study

This study provides a long-term, hourly scaled bottom-up energy supply and demand model which can evaluate the Turkish electricity generation sector under the conditions applied by various government policies. The Integrated MARKAL Energy Flow Optimization Model System (TIMES) generator, named VEDA, is used to model a base and policy scenarios concerning government incentives for renewable energy.

In this study, the model provides a range of future energy system mix for the Turkish electricity generation sector to a range of policy constraints for the period from 2018 to 2030 with two to five-year increments, but in each case, projected energy demand requirements optimized to least cost. It analyzes energy policy choices and scenarios and assesses the implications for the economy (technology choices, prices, output, etc.), energy mix and energy dependence, and the environment. It is used to study the implications of emerging technologies and alternative policy choices, such as meeting renewable energy targets and carbon reduction strategies.

The primary resource mix, a system-wide cost analysis, investment decisions comparison (technology choices over time horizons), and potential electricity prices are generated. The results of the proposed scenarios are compared with the reference scenario. The results indicate the least cost strategies that can be implemented for the desired energy/electricity sector outcomes, such as higher penetration of renewable energy and/or reduced energy import.

The importance of this study roots from being the first attempt to model and examine the Turkish energy system in terms of the level of hourly electricity production and consumption with regional solar and wind power representations between 2018 and 2030 using TIMES methodology to assess the future pathways of the system under various policy options.

CHAPTER 2

2. LITERATURE REVIEW

Energy models analyze energy systems to guide decision-makers while defining future policies. Controversial issues such as nuclear energy, greenhouse gas emission limits, energy share, and stability are addressed by implementing energy models [9]. Two main modeling approaches are generally used to observe the relationship between the energy system and the economy. These are top-down and bottom-up models. The top-down energy models are aggregated models representing the macroeconomic approach, and the bottom-up models are disaggregated models representing the engineering approach [38]. Also, hybrid models combine these two engineering approaches to benefit from their advantages. The details, advantages, and disadvantages of top-down, bottom-up, and hybrid models are explained in the following chapters.

2.1 Top-Down Models

Top-down energy models reflect an entire economy on a national or regional level to evaluate the effects of energy and climate change policies. These models simulate economic improvements, energy demand, and supply, with other social and economic effects such as employment. They have an aggregated understanding of the energy sector. These macroeconomics models aim to equilibrate markets by using production factors while maximizing consumer welfare. They are currently being used to assess and evaluate energy and climate policies' economic and environmental costs. [9]

Energy Economy Environmental Damage Model (EN- DAM) is a ten-sector input-output model that utilizes oil extraction, processing, gas, and electricity sectors.

Agriculture, forestry, manufacturing, construction, transport, and services are added as non-energy sectors. Carbon dioxide, nitrogen oxides, and sulfur dioxide gases are used to analyze emissions. Sectoral interrelationships, energy, and environmental issues and policies are explored in this model.[8]

The Dynamic Integrated model of Climate and the Economy (DICE) and a more detailed version, the Regional Integrated model of Climate and the Economy (RICE), are integrated assessment models. These models associate economic well-being with a path of consumption.[25]

2.2 Bottom-Up Models

Bottom-up models, also known as systems engineering approaches, analyze technical improvements in the energy system based on a complete description of technological possibilities and potentials. Energy flows, a resource network, and final users are all described in detail. Resource extraction to final use paths is introduced [37]. With these instructions, Bottom-up models can identify the optimal technologies based on costs, policies, excesses, and other factors [9].

Technical and economic parameters, which can be altered, are included in the technologies. Instead of energy types, bottom-up models portray demand as end-use demands such as lighting, cooling, and heating [18]. Sectoral outputs are produced by combining each technology's outputs in these models. As a result, a sector's production function is generated implicitly, and its complexity is determined by the sector's reference energy system [20]. Partial equilibrium, simulation, multi-agent, and optimization models are the four types of bottom-up models [9].

Under specific constraints, optimization models try to find the optimal set of technological options with the minimum cost. These models use discrete energy conversion technologies since data on investment and operation costs are required for optimization. Several market flaws are overlooked by optimization models [9].

Tash et al. develop a TIMES model to evaluate the German energy system under the heterogeneity of the investment decisions of actors. In this study, Germany is divided into four regions to mimic the variability of renewable resources and electricity demands. The development costs and losses of the grid are also included within the model. The developed TIMES Actors Model (TAM) is tested separately under the CO2 taxes policy and a national renewable quota policy. The results show that the system is quite differently affected by the CO2 taxes and renewable targets. These results can help to improve investment decisions for a targeted policy [32].

Astudillo et al. constructed a multi-sector TIMES energy system model of Quebec for 2011-2050 to evaluate the unrealized energy-efficiency potential of the household sector. They use time-series analysis to find the intra-annual availability of renewable energy sources and electricity imports. Their model includes heating and conservation measures in the residential sector. The results show that there would be a peak demand increase by 30% due to GW mitigation efforts toward the low carbon societies. Better-insulated building envelopes in the new houses reduce the 14% of GW mitigation costs. Also, heat pumps are the most cost-effective heating technology, according to the results. The constructed model favors run-of-river power plants to reduce the mitigation costs [3].

Postic et al. use a TIMES model to study the high renewable energy potentials of Central America, South America, and the Caribbean countries. They construct a MarkAL/TIMES bottom-up model. Five policy scenarios are created based on the guarantees of the United Nations Framework Convention on Climate Change. Their model with rigid climate policies achieves emission reductions of 40% by 2050. Also, the results show that the major contributor to emission reductions in the agriculture sector [27].

Tattini et al. constructed an Energy/Economy/Environment/Engineering (E4) model named TIMES-DK to analyze the long-term decarbonization of the Danish transport sector. TIMES-DK is Denmark's integrated energy system model that includes modes and modal shift availability. The modal shift is based on levelized costs of modes, speed, and infrastructure requirements. They conduct four sensitivity analyses to determine the effect of modal shift key variables on the decarbonization of the transport sector. The results show that more efficient decarbonization is realized by the less strict travel time budget (TTB) and increased speed of public buses [33].

Seck et al. investigate the French power sector's reliability through an endogenous reliability indicator using their TIMES-FR model. They consider short-term power grid operation conditions in long-term prospective analysis. The model uses additional backup and flexible options to sustain the grid's stability. Their results show how the grid's stability can be maintained with an increasing share of renewables. They observe that around 65% of variable renewable energy sources (VREs) can be achieved with currently installed capacity without any impairment in grid reliability.

They conduct various scenarios and compare them. Their study shows that the power exchanges with neighboring regions with a higher share of renewable energy are important for maintaining grid reliability [30].

Vaillancourt et al. propose a bottom-up energy model named as TIMES-Canada. Using their multi-regional energy model, they evaluate five (one base and four alternate) scenarios regarding the low and high oil prices and slow and fast socio-economic growth trends. Their database includes 5000 technologies and 400 commodities. According to the results, the final energy consumption of Canada increases by 47% within the time horizon (2007 – 2050). In the long term, oil products are partially replaced by electricity and biofuels. Two main trends are illustrated. First, onshore conventional oil sources are gradually replaced with unconventional and offshore sources. Second, due to increased oil prices and decreases in renewable technology costs, renewables have a recognizable penetration in the electricity mix after 2035 [36].

Daly et al. propose a TIMES model to evaluate the travel behavior of California and Ireland between 2008 and 2030. Their model consists of three vehicle types train, car, and bus. They impose a constraint on overall travel time in the system and introduce a cost for infrastructural investments. The model prefers public transportation for both California and Ireland if no travel time constraint is defined. Otherwise, the mode choice depends on the income and investment cost assumptions and emission constraints in the mitigation scenario. While the investment cost is low, a new rail is introduced for short distances. Also, the bus capacity for long distances is increased. Rail is also chosen for long distances at higher investment costs, too [4].

Yang et al. construct a bottom-up, economic optimization model of the California Energy System. The model, named CA-TIMES, includes all energy sectors of California. Their aim is to reduce GHG emissions to 80% below 1990 levels by 2050. For this purpose, thirteen different scenarios are developed. According to the results, this reduction in GHG emissions is possible. The GHG mitigation costs are calculated for each scenario. The carbon capture and sequestration technologies are the major actors in achieving low mitigation costs, which are found as reasonable [40].

Salvucci et al. propose a TIMES model, TIMES-Nordic, to study the role of modal shift in the decarbonization of Scandinavian energy systems. This is the first study that uses the substitution elasticities to model passenger and freight modal shifts.

The results are compared under an increasing emission tax. Using cars, trucks, and ships is mainly substituted by rail while low carbon transition is forced [28].

Tetik proposes a bottom-up energy model to determine Turkey's future energy technology mix while focusing on the electricity sector. The model includes hourly-based demand values of electricity for aggregated weekdays, Saturdays, and Sundays. The horizon of the model is between 2012 and 2050. Also, the whole country is represented as one region. Five different scenarios are applied under various policy options. The paper presents a resource mix, cost analysis, investment decisions, and electricity prices according to the results of scenarios. According to the results, it is seen that emission abatement is less costly and more effective than wind and solar incentives [34].

No up-to-date study considers the Turkish energy system on an hourly time-slice basis while considering non-dispatchable energy sources and transmission grid. This study aims to fill the gap in the literature by proposing a full-scale bottom-up energy model. The model includes regional hourly demand and supply of electricity. Also, the hourly availability of non-dispatchable energy sources is implemented. This is the first study that models Turkish non-dispatchable electricity production hourly. Different scenarios are introduced to evaluate the future energy mix of Turkey.

2.3 Hybrid Models

Hybrid models are developed to minimize the limitations of top-down and bottom-up models. This can be achieved by combining the features of top-down and bottom-up models. Top-down models have macroeconomic completeness with feedback loops, use aggregated data for prediction, and are based on observed market data and internalization of behavioral relationships. Bottom-up models have a high level of technical clearness, use non-aggregated data for exploring, are independent of observed market data, and can evaluate the cost of technological options. [9,30]

The MERGE model is a fully integrated applied general equilibrium model. All regions are independent of each other based on pricing. Their demands and supplies are in equilibrium for international commodities like oil, gas, and carbon emission.[22]

Technological details and a basic representation of the macroeconomy are combined in MARKAL-MACRO and TIMES-MACRO models. In MARKAL-MACRO, while MARKAL is focused on being technology specific, it is supported by

MACRO that maximizes national utility function by being compact, single sector, optimal growth dynamic intertemporal general equilibrium model.[21]

Model for Energy Supply Strategy Alternatives and their General Environmental Impact-MACRO (MESSAGE-MACRO) is a hybrid model that combines MESSAGE, the LP energy supply model, with the nonlinear macroeconomic model MACRO. In this model, MESSAGE generates prices using total and marginal energy supply costs, and MACRO adjusts total energy demand by a quadratic demand function. Then again, MESSAGE runs and generates prices on the demand, which MACRO adjusts until the price and demand stabilize.[23]

The SCREEN model is a hybrid model that combines technical details of the power sector and a general equilibrium framework that is macroeconomically computable.[19]

CHAPTER 3

3. METHODOLOGY

In this study, TIMES modeling approach has been used to model Turkey's energy system concerning the electricity sector. In section 3.1 TIMES modeling approach is explained briefly, while extensive details about the reference system and mathematical formulation can be found in sections 3.2 and 3.3.

3.1 The TIMES Energy Modeling System

The Integrated MARKAL-EFOM System (TIMES) is an economic model generator suitable for deploying single, multi-regional, or global energy systems. It is developed by the Energy Technologies Systems Analysis Program (ETSAP) of the International Energy Agency (IEA). It can be applied to analyzing a single or entire energy sector. While it represents energy dynamics over a multi-period time horizon in a technology-rich manner, TIMES bottom-up model aims to generate a least-cost energy system using linear programming.

The user provides data about estimated existing stocks of energy-related technologies with their characteristics and availabilities in the future, in addition to the present and future sources of primary energy supplies with their availabilities. The user must also provide the estimates of end-use energy service demands for each region.

Within the scope of provided data, TIMES model decides which technologies to invest in and operate, the amounts of primary energy supplies used, and the energy trade of each region over the model horizon. It aims to balance supply and demand at a minimum loss of total surplus, which also means minimum global cost.

TIMES is a vertically integrated model of the comprehensive energy system, which has a scope that extends beyond merely energy-related issues to include environmental emissions and maybe materials associated with the energy system.

Furthermore, the model is well suited to analyze energy-environmental policies, which may be accurately represented thanks to the explicit depiction of technologies and fuels across all sectors. The quantities and prices of various commodities are in equilibrium in TIMES, as they were in its MARKAL forebear [20].

3.2 Reference Energy System

A network diagram can show the relationships among various entities in TIMES Reference Energy System (RES). This diagram shows processes as boxes and commodities as vertical lines. The links between processes and commodities are commodity flows.

Processes, also known as technologies, represent power plants, factories, conversion plants, import or export processes, and various demands such as heating, electricity, fuel, and more. Commodities are entities that are produced or consumed by a process. They can be energy carriers, materials, demand, and environmental indicators. Commodity flows show the connection between process and commodities, which are outputs or inputs for any time slice in any region.

Figure 3.1 shows a part of the RES containing a single energy service demand, residential space heating. In this RES, gas, electricity, and heating oil are the only commodities that carry energy for end-use space heating. One gas plant, one oil refinery, and three electricity-generating plants produce these energy carriers. Also, the extraction process for domestic wet gas, coal, and crude oil can be seen in the diagram. There is one oil import process that represents the imported oil. After each process, the commodity changes its name to enable a proper connection between processes [20].

3.3 The Mathematical Formulation of The TIMES Model

This chapter provides a simplified formulation of TIMES linear program as expressed in TIMES documentation of Loulou et al. [20]. A brief description of the indexes, decision variables, objective function, and constraints can be found above.

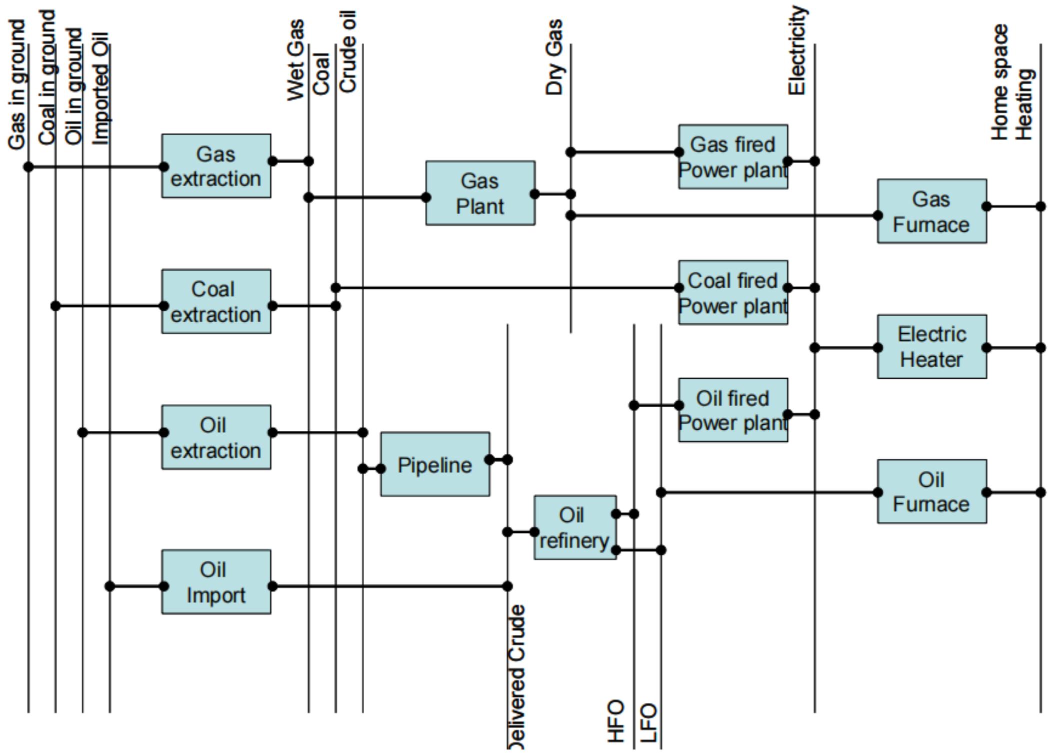

Figure 3.1 Sample from a Reference Energy System [20]

3.3.1 Indexes

In the model, index ***r*** indicates the region, ***t*** is the time-period where ***v*** is used for the vintage year of an investment when there is no vintage, and ***v*** is equal to ***t***. ***p*** represents the process or technology. ***s*** is a time-slice that helps to track commodities and processes at a finer level than the annual level. c represents commodities such as energy, demand, etc. [20]

3.3.2 Decision Variables

An initially unknown decision variable represents each choice made by the model. TIMES has variables that are prefixed with "VAR" and an underscore. Some decision variables which are related to this study are explained below.

VAR_NCAP(r,v,p): New capacity invested for process *p*, in period *v* and region *r*. Units of these variables change throughout technologies. Typically, units are PJ/year for energy technologies and GW for conversion technologies.

VAR_CAP(r,t,p): Total installed capacity of process *p* in region *r* and period *t* and with all vintages if available. These variables are only defined when user constraints or bounds exist. They do not appear in other equations.

VAR_ACT(r,v,t,p,s): Activity level of a process *p*, in region *r*, and period *t* with vintage *v* and time-slice *s* options. Without time-slice, only annual activity is noted. The typical unit is PJ for all processes.

VAR_FLO(r,v,t,p,c,s): The quantity of commodity *c* produced or consumed by process *p*, in region *r*, and period *t* with vintage *v* and time-slice *s* options. This variable can be used to create flexible processes. PJ is typically used as the unit for all types of processes.

VAR_IRE(r,v,t,p,c,s,exp) and *VAR_IRE(r,v,t,p,c,s,imp):* Quantity of commodity *c* (PJ/year) exported (exp) or imported (imp) by region *r* through process *p* in period *t* with options of vintage *v*, and time-slice *s*. It represents inter-regional exchange.

VAR_DEM(r,t,d): Demand for end-use energy service *d*, in region *r*, and period *t*. It is defined by the user for the reference scenario and can be changed by alternate scenarios.

Other variables are related to the objective function, commodity, and flow. More detailed information can be obtained in the TIMES documentation. [20]

3.3.3 Objective Function

TIMES objective function is the negative of the surplus maximization objective. It minimizes the total system cost. The total cost of each year for the model horizon is calculated and discounted to a specific year. The elements below are used to calculate this total cost:

- Capital costs of investments or dismantling processes alongside fixed and variable operation and maintenance costs for technologies.
- Costs of exogenous imports and domestic resource extractions.
- Revenues of exogenous exports.
- Delivery costs of commodities that are consumed by processes.
- Taxes and subsidies are related to the commodity flow, activities, and investments. They are not real costs and are not reported within the regular costs.
- Revenues from recuperation of commodities when they are released by dismantling of a process.
- Damage costs for the environment if any pollutant is defined.

- Salvage value of processes and commodities at the end of the model horizon.
- Welfare loss from reduced end-use demands.

TIMES can spread the investments over periods instead of lump investments which is helpful for progressive processes. Repeated investment decisions are also possible. Some dismantling capital costs may incur much later than the investment period. The capital cost of a process is associated with economic life (ELIFE) rather than technical life (TLIFE). It may also be annualized. [20]

The capital costs are computed yearly, while salvage value is calculated as a lump sum revenue at the end of the model horizon. It is then subtracted from the total cost and discounted to a reference year. All other annual costs are included in annualized capital cost payments to get ANNCOST value. Then a total net present value of annual costs for each region discounted to a reference year is calculated. Finally, all regional discounted costs are aggregated into the total cost. The objective function below shows this total cost to be minimized while computing equilibrium. [20]

$$NPV = \sum_{r=1}^{R} \sum_{y \in YEARS} \left(1 + d_{r,y}\right)^{REFYR-y} \cdot ANNCOST(r, y) \tag{3.1}$$

NPV	: Net present value of the total cost for all regions, objective function
ANNCOST (r, y)	: Total annual cost in region *r* and year *y*
$d_{r,y}$	: General discount rate
REFYR	: Reference year for discounting
YEARS	: Set of years including all years in, before and after the horizon if available
R	: Set of regions

3.3.4 Constraints

The physical relationships are expressed as constraints in the TIMES models. They must be satisfied to represent related energy systems properly. The total discounted cost is minimized while satisfying these massive amounts of constraints.

3.3.4.1 Capacity Transfer

The investment in technology increases its installed capacity until the end of its technical life. When their technical life end, technology capacities are decreased. The model calculates a technology's available capacity by considering both the increase by investment and the decrease by the end of life up to that period. Therefore, the total available capacity for each technology *p*, in region *r*, in period *t* with all vintages is equal to the total invested amount in the past and current periods, and the capacity is still available [20].

$$VAR\_CAPT(r,t,p) = \sum_{t-t'<LIFE(r,t',p)} VAR\_NCAP(r,t',p) + RESID(r,t,p) \qquad (3.2)$$

VAR_CAPT (r, t, p)	: Total available capacity of technology *p* in period *t*, in region *r*
LIFE (r, t', p)	: Technical lifetime of technology *p* in period *t'*, in region *r*
VAR_NCAP (r, t', p)	: The amount of new capacity investment of technology p in period *t'*, in region r
RESID (r, t, p)	: The amount of residual capacity of technology p available in period *t*, in region *r*

3.3.4.2 Definition of Process Activity Variables

TIMES uses a constraint that equalizes the weighted set of flow variables and overall activity variables to construct a relationship between activity and flow variables. To achieve this, the group of commodities for the process is identified; then, in a process that consumes or produces one commodity, the input or output commodity is chosen by the modeler to define the activity level. The *primary commodity group(pcg)* is used for processes with multiple commodities as input or output [20].

$$VAR\_ACT(r,v,t,p,s) = \sum_{c\in pcg} VARFLO(r,v,t,p,c,s)/ACTFLO(r,v,p,c) \qquad (3.3)$$

VAR_ACT (r, v, t, p, s)	: Activity level of technology *p* in region *r*, with vintage year *v*, in period *t*, for time-slice *s*

VARFLO (r, v, t, p, c, s) : Flow level of commodity *c* in technology *p*, in region *r*, with vintage year *v*, in period *t*, for time-slice *s*

ACTFLO (r, v, p, c) : Conversion factor for activity from technology p with vintage year v to the flow of commodity c in region r

3.3.4.3 Use of Capacity

The availability factor decides the use of capacity. In some time-slices or periods, the model may prefer to use less capacity if this decision is beneficial for minimizing the total cost. The modeler can force the model to use the total capacity of any process. The constraint below ensures that the activity of a process does not exceed its available capacity for each time slice, period, and region [20].

$$AR\_ACT(r,v,t,p,s) \quad \leq or = \; VAF(r,v,t,p,s) * PRC\_CAPACT(r,p) * FR(r,s) * VAR\_CAP(r,v,t,p) \qquad (3.4)$$

AF (r, v, t, p, s) : Availability factor of technology *p* in region *r*, with vintage year *v*, in period *t*, for time-slice *s*

PRC_CAPACT (r, p) : Conversion factor for capacity and activity of a technology *p* in region *r*

FR (r, s) : Fraction of time-slice *s*

VAR_CAP (r, v, t, p) : Capacity of technology *p* in region *r*, with vintage year *v*, in period *t*

3.3.4.4 Commodity Balance Equation

The commodity balance equation states that the sum of domestic production and imports into a region must be balanced with the consumed and exported amount of each commodity in every time slice specified by the user. By allowing excess production, this constraint creates equality for the supplies and inequality for demands, emissions, and energy carriers [20].

$$\left[\sum_{p,c\in TOP(r,p,c,\text{out})}[VAR\_FLO(r,v,t,p,c,s) + VAR\_SOUT(r,v,t,p,c,s) * STG\_EFF(r,v,p)] + \sum_{p,c\in RPC\_IRE(r,p,c,\text{imp})} VAR\_IRE(r,t,p,c,s,\text{imp}) + \sum_{p}[Release(r,t,p,c) * VAR\_NCAP(r,t,p,c)]\right] * COM\_IE(r,t,c,s) \geq or = \sum_{p,c\in TOP(r,p,c,\text{in})}[VAR\_FLO(r,v,t,p,c,s) + VAR\_SIN(r,v,t,p,c,s)] + \sum_{p,c\in RPC\_IRE(r,p,c,\backslash\exp)} VAR\_IRE(r,t,p,c,s,\backslash\exp) + \sum_{p}[Sink(r,t,p,c) * VAR\_NCAP(r,t,p,c)] + FR(c,s) * VAR\_DEM(c,t) \tag{3.5}$$

VAR_SOUT/SIN (*r*, *v*, *t*, *p*, *c*, *s*)	: Storage output/input flow in region *r* with vintage year *v* in period *t* of technology *p* for time-slice *s of commodity c*
TOP (*r*, *p*, *c*, *in/out*)	: Input/output flow in region *r* into/from technology *p* of commodity *c*
RPC_IRE (*r*, *p*, *c*, *imp/exp*)	: Import/export flow into/from region *r with* technology *p* of commodity *c*
STG_EFF (*r*, *v*, *p*)	: Efficiency of storage technology *p* in region *r* with vintage year *v*
COM_IE (*r*, *t*, *c*, *s*)	: Infrastructure efficiency in region *r* in period *t* of commodity *c* for time-slice *s*
Release (*r*, *t*, *p*, *c*)	: The amount of commodity *c* necessary for a unit of new capacity of technology *p* dismantled in region *r* in period *t*
Sink (*r*, *t*, *p*, *c*)	: The quantity of commodity *c* required for a unit of new capacity of technology *p* in region *r* in period *t*
FR (*s*)	: Fraction of the year covered by time-slice *s*

3.3.4.5 Defining Flow Relationships in a Process

Input and output commodities of a process are dependent on each other. This constraint equalizes the ratio of outputs to input flow to a constant to maintain the relationship between input and output flows of technology. Therefore, this constraint defines the essential efficiency for single input/output processes [20].

$$\sum_{c\in cg2} VAR\_FLO(r,v,t,p,c,s) \;=\; FLO\_FUNC(r,v,cg1,cg2,s) \quad (3.6)$$

$$* \sum_{c\in cg1} COEFF(r,v,p,cg1,c,cg2,s) \;*\; VARFLO(r,v,t,p,c,s)$$

cg1	: Input commodity group
cg2	: Output commodity group
FLO_FUNC (*r*, *v*, *cg*1, *cg*2, *s*)	: Efficiency ratio of technology *p* in region *r* with vintage year *v* which consumes cg1 and produces cg2 for time-slice *s*
COEFF (r, v, p, cg1, c, cg2, s)	: Coefficient for harmonization of different time-slice resolutions of flow variables

3.3.4.6 Limiting Flow Shares in Flexible Processes

Previous constraints were regulating the input-output flows on the commodity group level but not limiting commodity shares which causes processes to be flexible. Upper and lower bounds can be determined by assigning FLO_SHAR coefficients to the commodities in Equation 3.7 to limit flexibility [20].

$$VAR\_FLO(c) \leq, \geq, = FLO\_SHAR(c) * \sum_{c'\in cg} VAR\_\,FLO(c') \quad (3.7)$$

3.3.4.7 Peaking Reserve Constraint

This constraint states that at each time period and each region, the capacity of all commodity-producing processes must have more than average demand in the peak time slice by a specific percentage, which is COM_PKRSV, due to the fluctuations of demand over time slices [20].

$$\sum_{p\ producing\ c=pcg} [PRC\_CAPACT(r,p) * Peak(r,v,p,c,s) * FR(s) * VAR\_CAP(r,v,t,p) * VAR\_ACTFLO(r,v,p,c)] + \sum_{p\ producing\ c \neq pcg} [NCAP\_PKCNT(r,v,p,c,s) * VAR\_FLO(r,v,t,p,c,s)] + VAR\_IRE(r,t,p,c,s,i) \geq [1 + COM\_PKRSV(r,t,c,s)] * \sum_{p\ consuming\ c} [VAR\_FLO(r,v,t,p,c,s) + VAR\_IRE(r,t,p,c,s,e)] \tag{3.8}$$

NCAP_PKCNT (r, v, p, c, s) : Fraction of technology *p*'s capacity in a region *r* for period *t* and commodity *c* that is allowed to contribute to the peak load in time-slice *s*

COM_PKRSV (r, t, c, s) : Peak reserve coefficient for *a* commodity *c* in period *t* for time-slice *s* in region *r*

3.3.4.8 Commodity and User Constraints

The modeler can use user-defined constraints for TIMES variables to processes and commodities, besides the standard constraints. It is also possible to limit variables of commodities, apply cumulative bounds on commodities and apply tax or penalty to the production of commodities in the TIMES modeling framework [20].

CHAPTER 4

4. TECHNOLOGICAL CHARACTERIZATION OF COMMODITIES AND PROCESSES

In this chapter, the general properties of the model are given alongside technological details of the electricity production processes and the demand. Each process has its related costs and commodity flows. The cost projections and supply limitations are implemented in the model. Fifteen different types of supply commodities are used within the model. These are solid biofuel, asphalt, imported coal, lignite, steam coal, liquefied natural gas, natural gas, nuclear, naphtha, geothermal, hydro, run-of-river, solar, and wind.

4.1 General Properties of the Proposed TIMES Model

In this study, an hourly scaled bottom-up model of the Turkish electricity sector is constructed within the framework of TIMES. The electricity sector is the main subject of this thesis. Only the demand and supply of electricity are included with its related commodities and processes.

The model includes commodities such as primary energy sources, energy carriers, and demand. The primary energy sources are supplied by supply technologies and converted into energy carriers by conversion technologies. These energy carriers are consumed by end-use technologies to satisfy the demand. The only demand category is electricity.

The model has a single region and a time horizon of 2018-2030. The milestone years are 2018, 2020, 2025, and 2030. The time-slices are set at monthly, daily, and hourly levels, while each month has one week, representing the average of the total month. 12 monthly, 7 daily, and 24 hourly time-slices are implemented. In total, each year includes 2016 time-slices. The representation of time horizon and time-slices are shown in Figure 4.1.

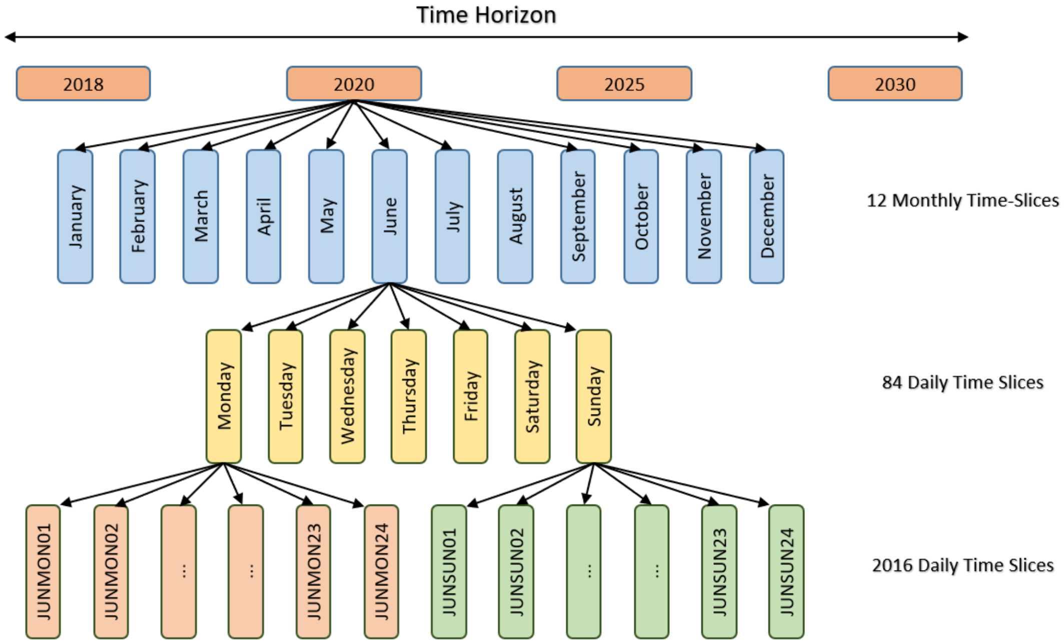

Figure 4.1 The representation of time horizon of TIMES model

Each time-slice includes monthly and daily abbreviations with their first three letters and hour of the day. For example, JANMON01 is the abbreviation of 1 AM, Monday, January.

The duration of each time-slice is calculated as a fraction of a year. The total of these fractions is equal to 1. Because of the difference in amounts of days each month, the values have minor fluctuations. The durations of time-slices related to January are shown in Table 4.1 as an example.

The Versatile Data Analyst (VEDA) is used as an interface program to integrate data with TIMES model. It generates suitable database and model files that can be run by GAMS (The General Algebraic Modeling System), a computer program that includes various solvers for different mathematical models. The interior point barrier algorithm is used within the CPLEX solver. This algorithm is relatively faster for solving large-scale problems such as the model of this study, where 2016 time-slices exist for various commodities and processes. Therefore, the amount of decision variables is more than 5 million in some scenarios.

The model uses 2018 US million dollars (MUSD 2018) as the currency unit throughout the whole system. All costs are discounted to 2018.

Table 4.1 Duration of each day in January as a fraction of year (Author's own calculation)

	January						
Hour	**Monday**	**Tuesday**	**Wednesday**	**Thursday**	**Friday**	**Saturday**	**Sunday**
1	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
2	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
3	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
4	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
5	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
6	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
7	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
8	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
9	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
10	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
11	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
12	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
13	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
14	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
15	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
16	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
17	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
18	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
19	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
20	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
21	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
22	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
23	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
24	0.00051	0.00050	0.00050	0.00051	0.00051	0.00051	0.00051
Daily	0.01214	0.01208	0.01208	0.01214	0.01214	0.01214	0.01214
Monthly	0.08487						

4.2 Versatile Data Analyst (VEDA)

Versatile Data Analyst, VEDA, is an environment that includes a set of tools that help to create and modify large databases for complex mathematical models. VEDA can also generate result reports. The first version of VEDA includes two subsystems, VEDA Front-End (VEDA_FE) and VEDA Back-End (VEDA_BE). It is a commercial software designed and developed by KanORS-EMR. [14]

First, the user provides model data to VEDA_FE, which creates the related TIMES model code. This data is inserted into VEDA_FE by using Excel files with flexible structures. Next, the generated TIMES code is run in the GAMS environment using a suitable solver. Then, VEDA_BE reads the results and creates the numerical and graphical outputs for the user. Finally, the user can modify the data and run the modified code for different scenarios. The relationship between data handling, model generation, model solution, and results handling for the first version of VEDA can be seen in Figure 4.2.

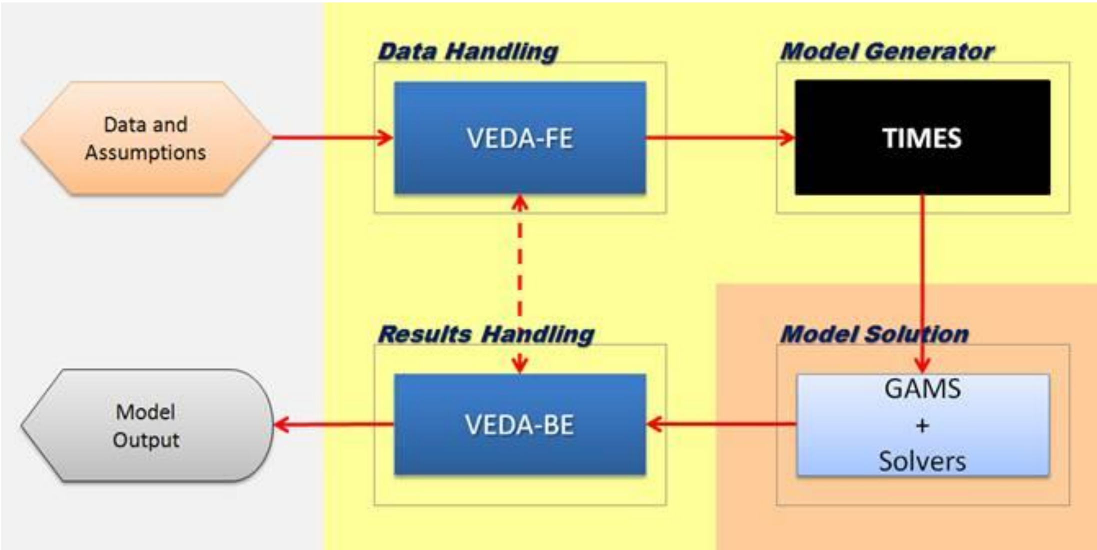

Figure 4.2 The overview of VEDA 1.0 [15]

A doctoral dissertation started the creation of VEDA at IIM Ahmedabad in 1996. KanORS-EMR created the first version of VEDA_BE in 2000 and VEDA_FE in 2007. ETSAP has supported it since 2000. In 2020, VEDA 2.0 version was published. It combines the two different systems, VEDA_BE and VEDA_FE, under the same interface. Therefore, the user can feed the data and see the results within the same environment. The modeler, user interface, and model relations of VEDA 2.0 can be seen in Figure 4.3. [11]

Figure 4.4. shows an example start page of VEDA 2.0. The user can see the files of recent models and announcements from developers on this page. Fundamental pages such as navigator, browse, item list, item detail, run manager, and results can be accessed by buttons on the top. For more information VEDA Documentation site can be browsed. [17]

VEDA is under continuous development, and KanORS-EMR occasionally publishes updates to increase efficiency. In addition, it has a support site and forum for its users.

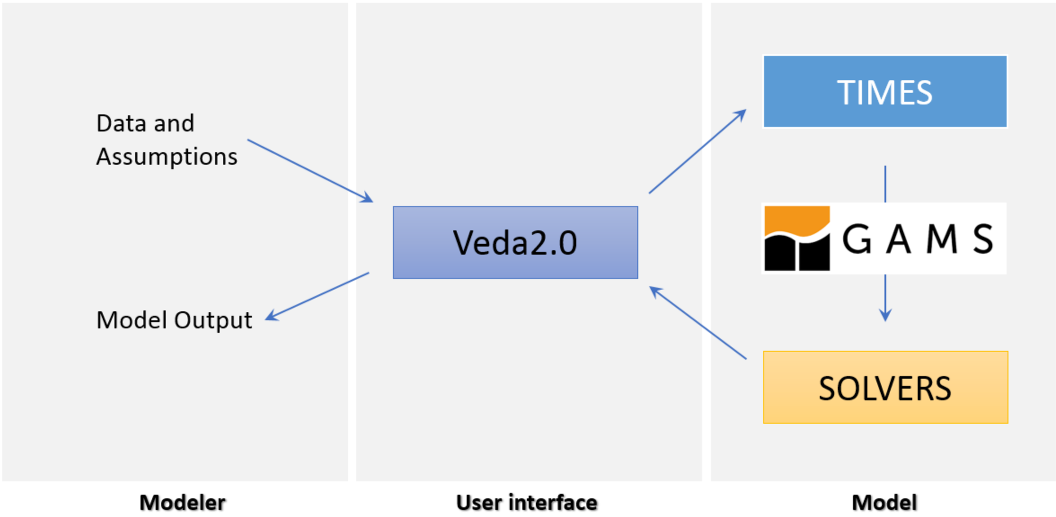

Figure 4.3 The overview of VEDA 2.0 [16]

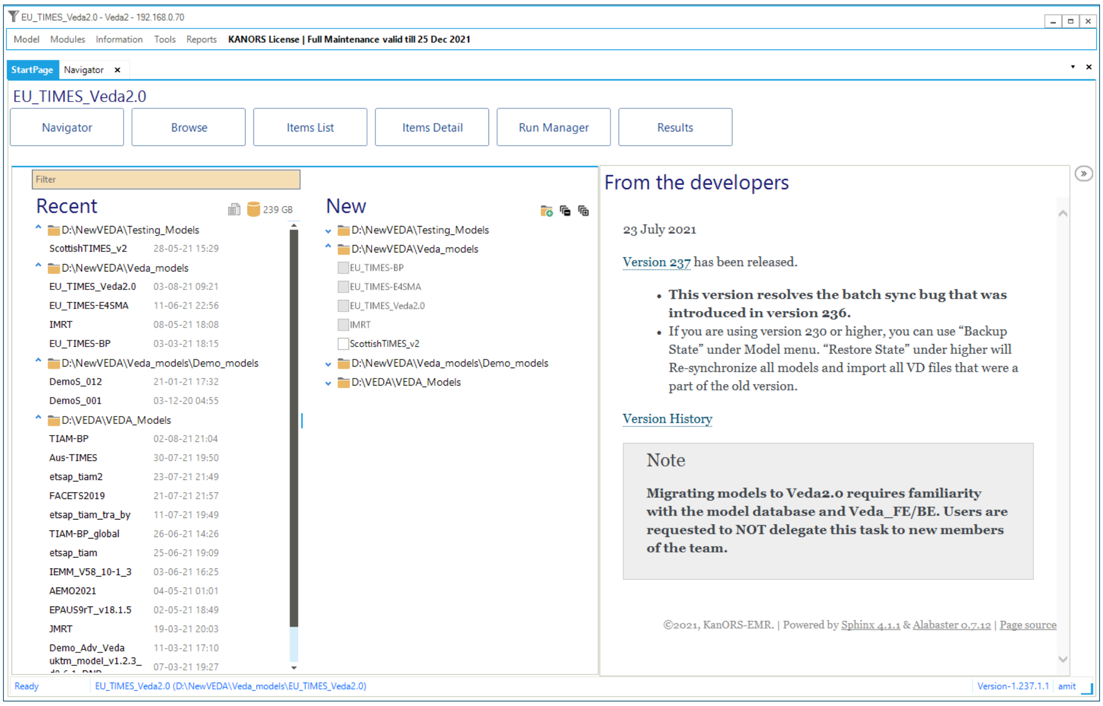

Figure 4.4 An example start page of VEDA 2.0 [13]

4.3 Demand

The demand is on the hourly time-slice level with 2016 time-slices for each year.

It is calculated by dividing the total electricity consumption in the electricity sector by time-slices fractions.

For 2018 and 2020, real consumption and production data are acquired from the transparency platform of the Turkish Energy Exchange company, EPİAŞ [31]. The electricity consumption on the 15th day of each month in PJ for 2018 can be seen in Figure 4.5. Hourly electricity consumption data for 2018 is used to find the demand fractions for 2018.

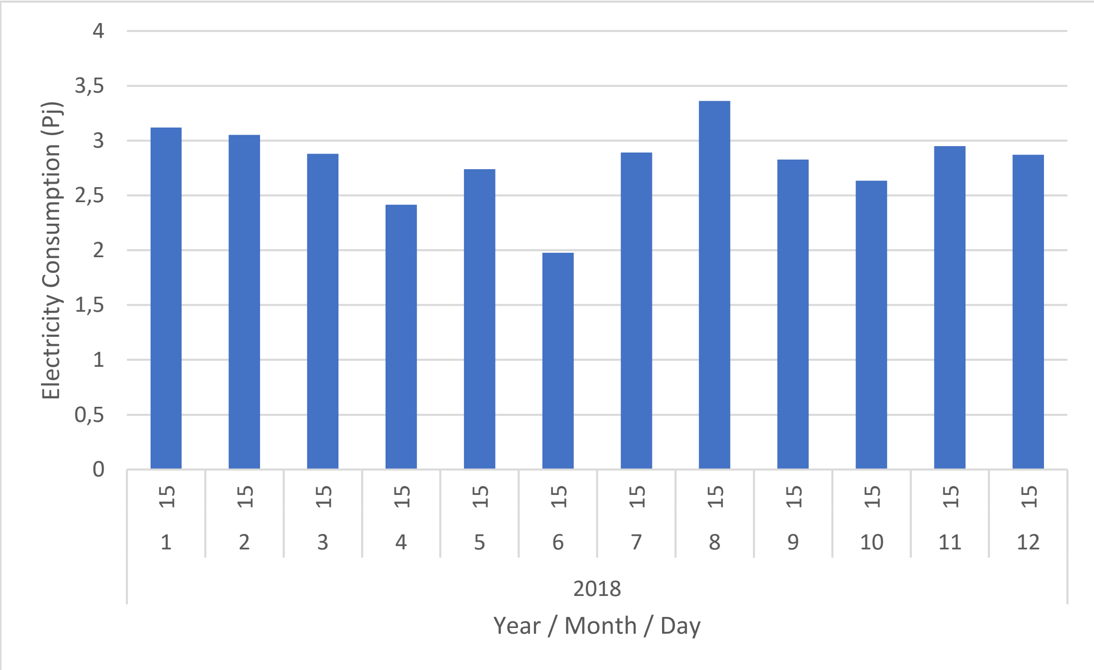

Figure 4.5 The electricity consumption on the 15th day of each month in PJ for 2018

Hourly electricity consumption data from 2007 to 2019 is used to calculate an average hourly demand fraction for future years [31]. The total consumption for each year between 2007 and 2019 can be seen in Figure 4.6. The average increase in demand between 2007 and 2019 is 4%. The future demands are calculated with the assumption of a 5% increase in demand for each year.

The energy consumption changes through the years while creating a pattern among seasons. It also changes among the days of the week and the hours of the day. An example of an hourly difference in electricity consumption can be seen in Figure 4.7 as the ratio of yearly consumption with the aggregation of each month includes one week. It is seen that the peak hours are mainly the same among the days of the week, except for Sunday. The demand is higher between 07:00 and 12:00. There occurs a small decline in demand until 17:00. The second peak in the day can be seen between 17:00 and 19:00. The consumption value decreases between 19:00 and 05:00. After that, the electricity demand increases until it reaches its peak value.

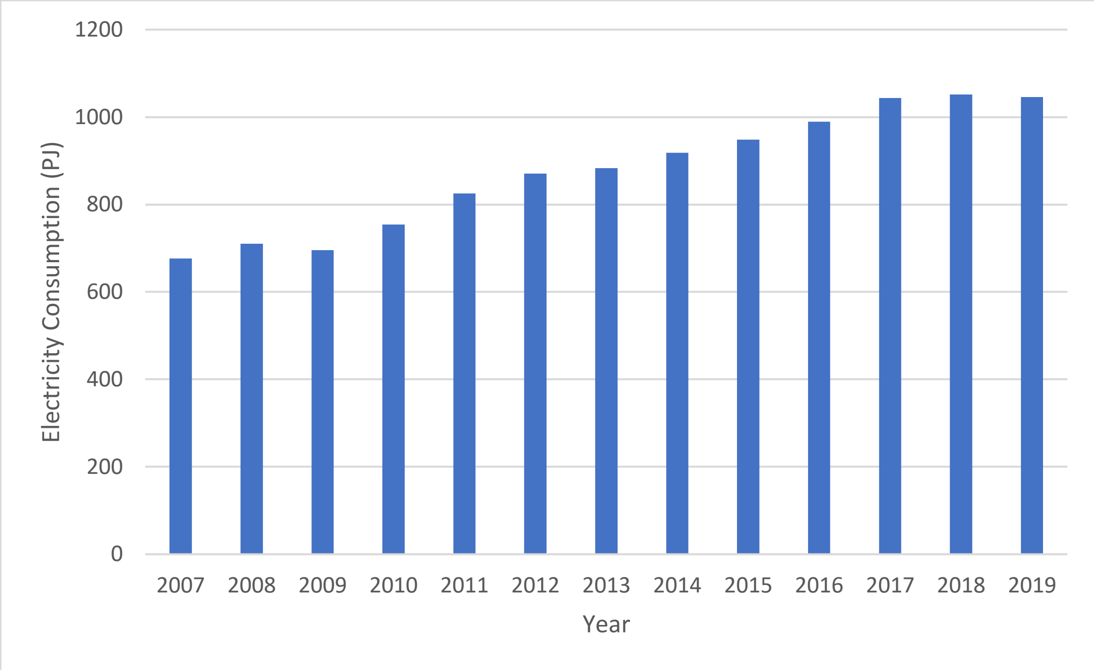

Figure 4.6 Hourly electricity consumption in PJ of Turkey in 2016, 2017, 2018, 2019

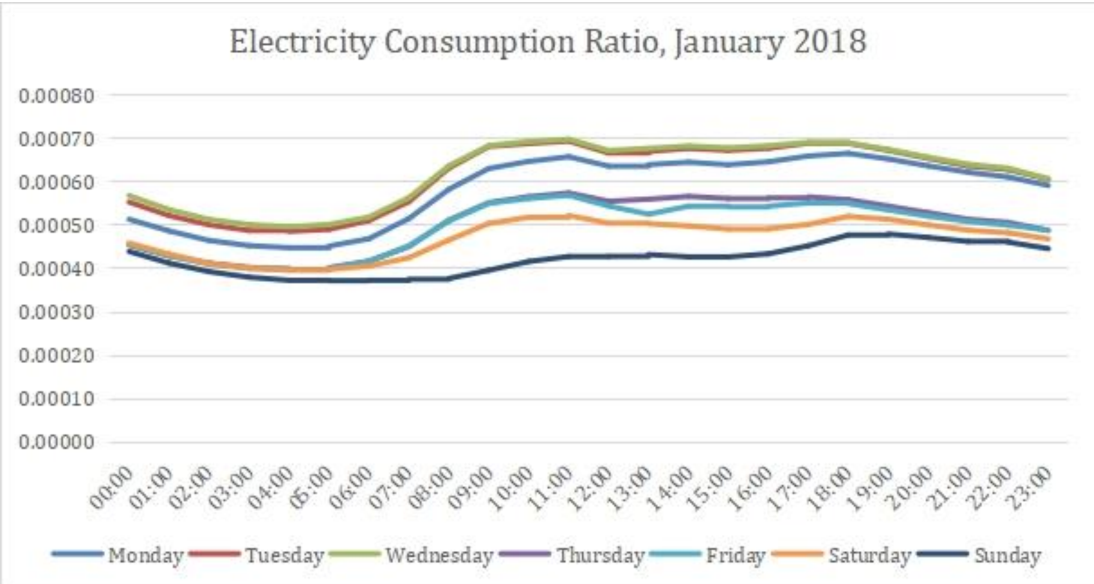

Figure 4.7 Electricity consumption ratio in January 2018 (Author's own calculation)

Some shifts in peak hours occur among months, but mainly the seasonal behavior remains the same. While the weekdays and Saturdays are affected considerably by season and month changes, the consumption behavior on Sunday does not significantly change.

4.4 Capacities of Technologies

The capacities of installed technologies are acquired from the Turkish Energy Market Regulatory Authority's monthly and yearly reports [5]. The installed capacities of all power plants according to their supply type in GW in 2018 can be seen in Table 4.2. There is no significant change in the capacities between months as the construction of power plants takes time. The solar plants are mostly unlicensed, with a total capacity of 5 GW. In Figure 4.8, only licensed solar power plant capacities are included. These installed capacities are used in the model for 2018.

Natural gas power plants have the greatest capacity among all power plants, with 32% of the total installed capacity. Hydropower plants have the second highest share, with 24.5%. Lignite and imported coal power plants follow them. The capacities are not significant without the efficiency and capacity factors that determine the amount of electricity produced.

For the future capacities, the capacity projections of TEİAŞ are used [35]. The power plants announced to be installed also implemented into the model with related planned capacities. Such as Akkuyu Nuclear Power Plant, which is currently under construction. The 2.4 GW capacity of the Akkuyu Nuclear Power Plant is planned to be installed until 2025 and will reach 3.6 GW in 2030. [2]

The top 69 provinces with better wind power capacities are selected and applied within the region models for future technologies. Others are discarded to ease the complexity of the model. These theoretical capacities are calculated with the help of Ahmet Yılmaz's website, where various news about the energy sector is collected. [1] For scenarios with non-regional future wind technologies, one future technology is defined with the maximum capacity as given in capacity projections.

For the future regional solar capacity, ten percent of each province's area is considered as a possible solar power plant site [10]. Utility and rooftop capacities are calculated separately with different efficiencies.

Table 4.2 Monthly installed power plant capacities in 2018

	January		February		March		April		May		June	
	Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)
Run-of-river	7.6	9.3%	7.6	9.2%	7.6	9.2%	7.6	9.2%	7.6	9.2%	7.6	9.2%
Asphalt	0.4	0.5%	0.4	0.5%	0.4	0.5%	0.4	0.5%	0.4	0.5%	0.4	0.5%
Hydro	19.9	24.3%	19.9	24.3%	19.9	24.2%	19.9	24.3%	20.1	24.5%	20.3	24.7%
Solid Bio Fuel	0.4	0.6%	0.5	0.6%	0.5	0.6%	0.5	0.6%	0.5	0.6%	0.5	0.6%
Natural Gas	26.3	32.2%	26.4	32.3%	26.4	32.2%	26.4	32.2%	26.4	32.0%	26.1	31.8%
Fuel Oil	0.7	0.9%	0.7	0.9%	0.7	0.9%	0.7	0.9%	0.7	0.9%	0.7	0.9%
Solar	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Imported Coal	8.8	10.8%	8.9	10.9%	8.9	10.9%	8.9	10.9%	8.9	10.9%	8.9	10.9%
Geothermal	1.1	1.3%	1.1	1.3%	1.1	1.4%	1.1	1.4%	1.1	1.4%	1.1	1.4%
Lignite	9.3	11.3%	9.3	11.3%	9.3	11.3%	9.3	11.3%	9.3	11.3%	9.3	11.3%
LNG	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Diesel	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Naphtha	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Wind	6.5	8.0%	6.5	8.0%	6.6	8.0%	6.6	8.1%	6.6	8.0%	6.6	8.0%
Steam Coal	0.6	0.8%	0.6	0.8%	0.6	0.8%	0.6	0.8%	0.6	0.7%	0.6	0.7%
Gross Total	81.7	100.0%	81.9	100.0%	82.0	100.0%	82.1	100.0%	82.3	100.0%	82.3	100.0%

Table 4.2 Monthly installed power plant capacities in 2018 (continued)

	July		August		September		October		November		December	
	Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)	Installed Capacity (GW)	Share (%)
Run-of-river	7.6	9.2%	7.6	9.2%	7.6	9.2%	7.7	9.3%	7.7	9.3%	7.7	9.3%
Asphalt	0.4	0.5%	0.4	0.5%	0.4	0.5%	0.4	0.5%	0.4	0.5%	0.4	0.5%
Hydro	20.5	24.9%	20.4	24.7%	20.5	24.8%	20.5	24.7%	20.5	24.7%	20.5	24.7%
Solid Bio Fuel	0.5	0.6%	0.5	0.6%	0.5	0.6%	0.6	0.7%	0.6	0.7%	0.6	0.7%
Natural Gas	25.9	31.5%	25.9	31.4%	25.8	31.2%	25.7	31.0%	25.7	31.0%	25.7	30.9%
Fuel Oil	0.7	0.9%	0.7	0.9%	0.7	0.9%	0.7	0.9%	0.7	0.9%	0.7	0.9%
Solar	0.0	0.0%	0.0	0.0%	0.1	0.1%	0.1	0.1%	0.1	0.1%	0.1	0.1%
Imported Coal	8.9	10.9%	8.9	10.8%	8.9	10.8%	8.9	10.8%	8.9	10.8%	8.9	10.7%
Geothermal	1.2	1.4%	1.2	1.4%	1.2	1.4%	1.3	1.5%	1.3	1.5%	1.3	1.5%
Lignite	9.3	11.3%	9.6	11.6%	9.6	11.6%	9.6	11.6%	9.6	11.6%	9.6	11.5%
LNG	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Diesel	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Naphtha	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Wind	6.6	8.1%	6.7	8.1%	6.8	8.2%	6.8	8.2%	6.9	8.3%	6.9	8.3%
Steam Coal	0.6	0.7%	0.6	0.7%	0.6	0.7%	0.6	0.7%	0.6	0.7%	0.6	0.7%
Gross Total	82.3	100.0%	82.5	100.0%	82.8	100.0%	83.0	100.0%	83.1	100.0%	83.2	100.0%

Table 4.3 Monthly electricity production in 2018

	January		February		March		April		May		June	
	Electricity Production (GWh)	Share (%)	Electricity Production (GWh)	Share (%)	Electricity Production (GWh)	Share (%)	Electricity Production (GWh)	Share (%)	Electricity Production (GWh)	Share (%)	Electricity Production (GWh)	Share (%)
Run-of-river	1485.9	5.7%	1552.3	6.7%	2048.6	8.4%	2460.0	10.8%	2566.0	11.0%	1986.3	8.4%
Asphalt	179.8	0.7%	176.1	0.8%	181.7	0.7%	156.0	0.7%	216.2	0.9%	164.7	0.7%
Hydro	3084.8	11.8%	2120.9	9.2%	3483.7	14.2%	3888.0	17.0%	3928.2	16.9%	3697.9	15.6%
Solid Bio Fuel	193.4	0.7%	182.2	0.8%	202.4	0.8%	202.6	0.9%	205.0	0.9%	194.6	0.8%
Natural Gas	8900.9	34.1%	7518.2	32.6%	6971.7	28.5%	6579.6	28.8%	5846.4	25.1%	6290.4	26.6%
Fuel Oil	78.7	0.3%	58.7	0.3%	58.9	0.2%	68.0	0.3%	87.1	0.4%	83.8	0.4%
Solar	1.7	0.0%	2.1	0.0%	3.2	0.0%	4.4	0.0%	3.8	0.0%	4.4	0.0%
Imported Coal	5788.4	22.2%	5394.3	23.4%	4041.2	16.5%	3840.4	16.8%	4541.0	19.5%	5060.7	21.4%
Geothermal	660.1	2.5%	571.2	2.5%	640.0	2.6%	627.3	2.7%	614.1	2.6%	579.4	2.5%
Lignite	3645.1	14.0%	3602.0	15.6%	3811.2	15.6%	3650.1	16.0%	3815.6	16.4%	3744.8	15.8%
LNG	0.7	0.0%	0.4	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Diesel	0.0	0.0%	0.0	0.0%	0.1	0.0%	0.0	0.0%	0.1	0.0%	0.1	0.0%
Naphtha	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Wind	1815.2	7.0%	1674.8	7.3%	2791.0	11.4%	1166.2	5.1%	1218.5	5.2%	1255.2	5.3%
Steam Coal	268.0	1.0%	224.8	1.0%	243.9	1.0%	227.3	1.0%	263.7	1.1%	579.4	2.5%
Gross Total	26102.6	100.0%	23078.0	100.0%	24477.5	100.0%	22870.0	100.0%	23305.7	100.0%	23641.9	100.0%

Table 4.3 Monthly electricity production in 2018 (continued)

	July		August		September		October		November		December	
	Electricity Production (GWh)	Share (%)	Electricity Production (GWh)	Share (%)	Electricity Production (GWh)	Share (%)	Electricity Production (GWh)	Share (%)	Electricity Production (GWh)	Share (%)	Electricity Production (GWh)	Share (%)
Run-of-river	1185.1	4.2%	968.1	3.6%	721.8	2.9%	721.6	3.1%	894.4	3.8%	1971.0	7.7%
Asphalt	200.0	0.7%	245.6	0.9%	197.8	0.8%	158.5	0.7%	194.2	0.8%	258.0	1.0%
Hydro	4665.5	16.4%	4615.6	17.1%	2948.6	12.0%	1726.1	7.5%	2802.5	11.9%	3996.9	15.6%
Solid Bio Fuel	204.5	0.7%	184.9	0.7%	186.7	0.8%	201.4	0.9%	216.2	0.9%	236.3	0.9%
Natural Gas	10660.8	37.4%	7854.5	29.2%	8861.2	36.2%	8025.7	34.7%	6842.2	29.0%	6999.7	27.3%
Fuel Oil	86.6	0.3%	75.5	0.3%	82.6	0.3%	88.8	0.4%	97.2	0.4%	91.7	0.4%
Solar	4.9	0.0%	4.7	0.0%	8.2	0.0%	12.2	0.1%	8.6	0.0%	5.6	0.0%
Imported Coal	5337.7	18.7%	5963.6	22.1%	5363.4	21.9%	5749.6	24.9%	5772.0	24.5%	5604.0	21.8%
Geothermal	573.3	2.0%	595.5	2.2%	578.7	2.4%	688.6	3.0%	711.9	3.0%	747.5	2.9%
Lignite	3879.9	13.6%	3816.4	14.2%	3606.8	14.7%	3979.9	17.2%	3758.9	15.9%	3806.3	14.8%
LNG	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Diesel	0.0	0.0%	0.0	0.0%	0.2	0.0%	0.1	0.0%	0.2	0.0%	0.2	0.0%
Naphtha	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Wind	1432.0	5.0%	2343.8	8.7%	1707.3	7.0%	1512.4	6.5%	2048.8	8.7%	1672.4	6.5%
Steam Coal	258.9	0.9%	259.2	1.0%	229.3	0.9%	234.1	1.0%	250.4	1.1%	290.0	1.1%
Gross Total	28489.3	100.0%	26927.1	100.0%	24492.5	100.0%	23099.1	100.0%	23597.5	100.0%	25679.7	100.0%

4.5 Electricity Production

The electricity production amounts by supply types are acquired from the Turkish Energy Market Regulatory Authority's monthly and yearly reports [5]. The electricity production of all power plants according to their supply type in GWh in 2018 can be seen in Table 4.3. There is a significant change in monthly electricity production. This change is mainly due to changes in the demand for dispatchable power plants and the availability of non-dispatchable power plants.

Natural gas power plants have the highest share in electricity production, with an average of 31%. Power plants supplied with imported coal have the second highest share, averaging 21%. Around 52% of total electricity is produced by power plants supplied with natural gas or imported coal.

Future electricity generations are calculated by the model while regarding the capacity and commodity limits, also with the technological specifications of processes.

4.6 Capacity Factors

Each technology includes both its technical efficiencies and capacity factors (CFs). The capacity factors are calculated by electricity production values in the past. The operator can control the dispatchable energy sources, such as coal, natural gas, oil, and biofuels. Their capacity factors are calculated on a seasonal level for existing technologies by using production values obtained from the Transparency platform of Energy Exchange Istanbul [31]. The capacity factors given in IEA's technology briefs are used for future technologies [7].

The hourly electricity production values for non-dispatchable sources between 2016 and 2019 are used to calculate capacity factors (CF) for run-of-river, solar, and wind sources for non-regional technologies.

Figure 4.8 shows that the run-of-river achieves its maximum average CF values in spring, and its CF is low in summer and winter. In April and May, the CF of run-of-river reaches around 60%. It becomes as low as 10% around October and November. There appears to be a slight fluctuation in the capacity factor between hours of the day. This fluctuation is expected to be caused by the operator.

In Figure 4.9, the average CF of wind can be seen. It reaches its maximum CF in summer and winter. The highest CF is around 60% in August. It has the lowest value, around 15%, in May. As wind capacity greatly depends on wind speed, which varies even between close regions, many fluctuations are seen.

The wind and run-of-river are available to be used as an energy source throughout the year for each hour of the day. On the other hand, solar energy cannot be used at night. The average CF of solar can be seen in figure 4.10. Solar power is available through all seasons, while rainy or snowy winters decrease their availability in November and December. It has the slightest fluctuations between the CFs of different days for the same hours in the same year. Therefore, more stable electricity production than wind or run-of-river power plants can be expected from solar power plants throughout the year.

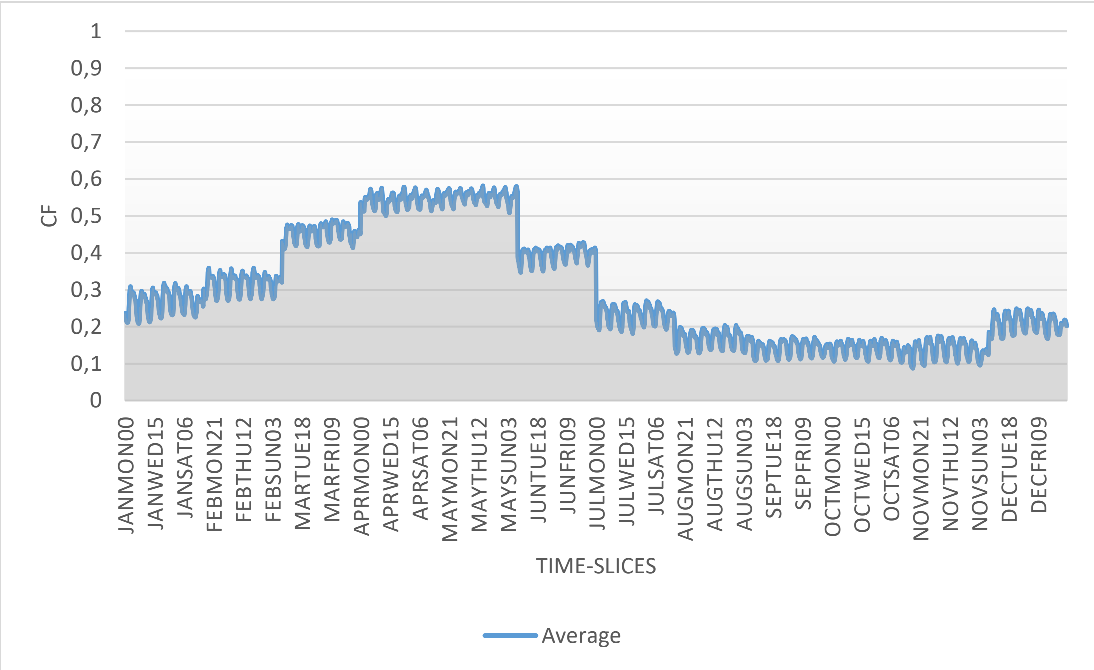

Figure 4.8 Average capacity factor of run-of-river between years 2016-2019

Some examples of hourly CFs of wind and solar are given in Figures 4.11, 4.12, 4.13, and 4.14. While the CF of wind does not vary significantly on the same day, it varies between months. For Wednesdays in May, it has an average CF of around 22%. For Wednesdays in August, the average CF becomes more than 43%. On the other hand, the solar CFs greatly vary on the same day between 0% and 60%. While no significant change between months as their averages are around 16% for May and 18% for August.

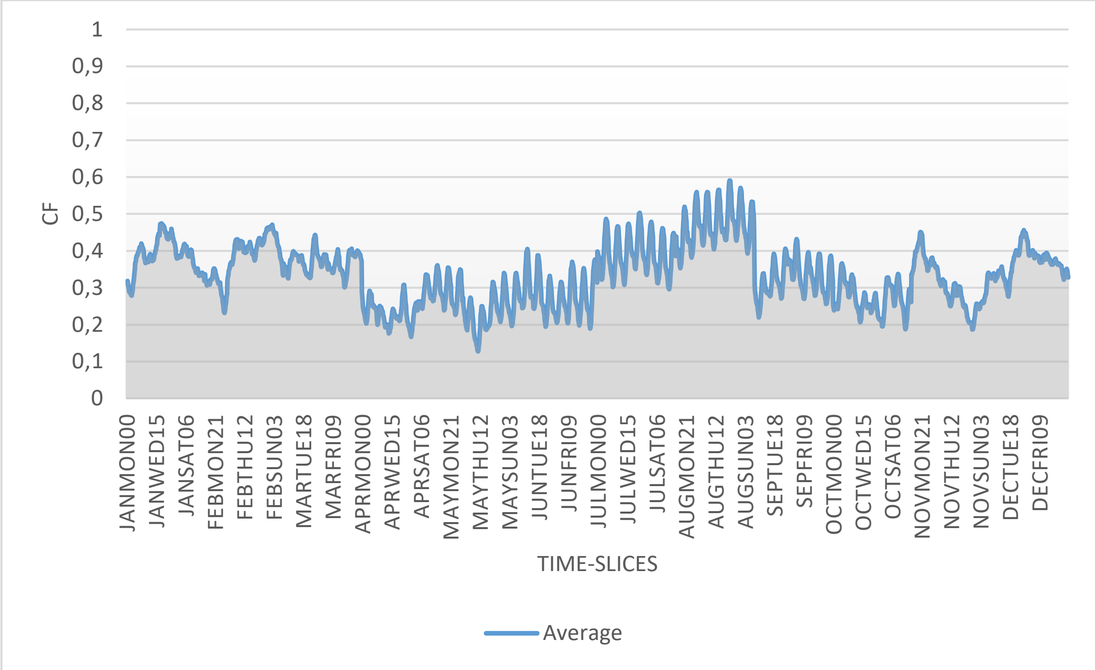

Figure 4.9 Average capacity factor of wind between years 2016-2019

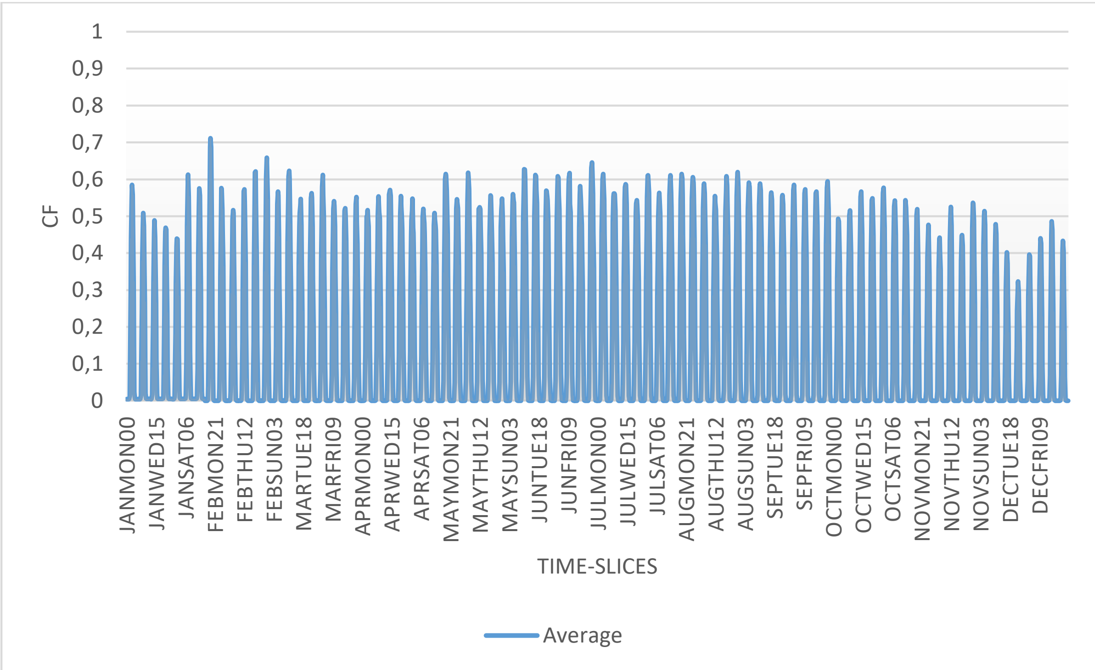

Figure 4.10 Average capacity factor of solar between years 2017-2019

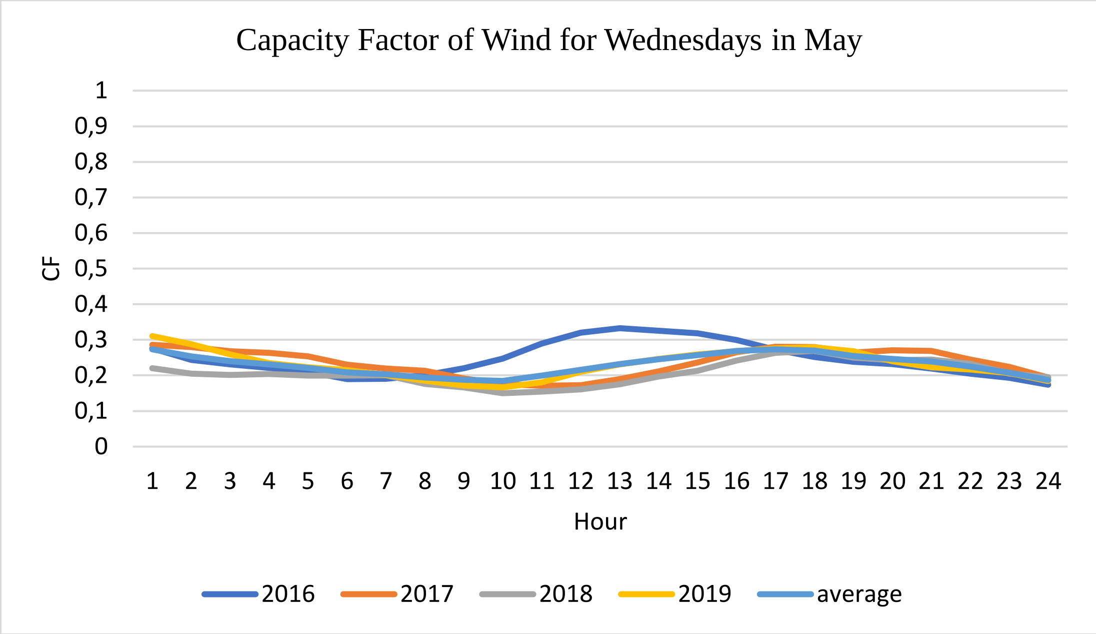

Figure 4.11 Capacity factor of wind for Wednesdays in May between 2016-2019

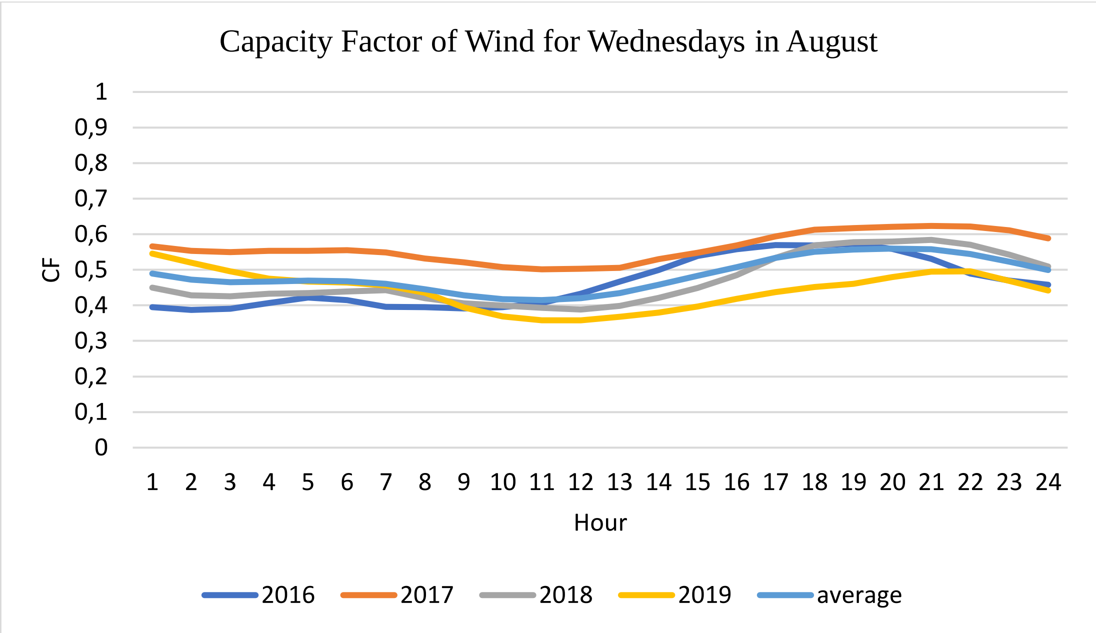

Figure 4.12 Capacity factor of wind for Wednesdays in August between 2016-2019

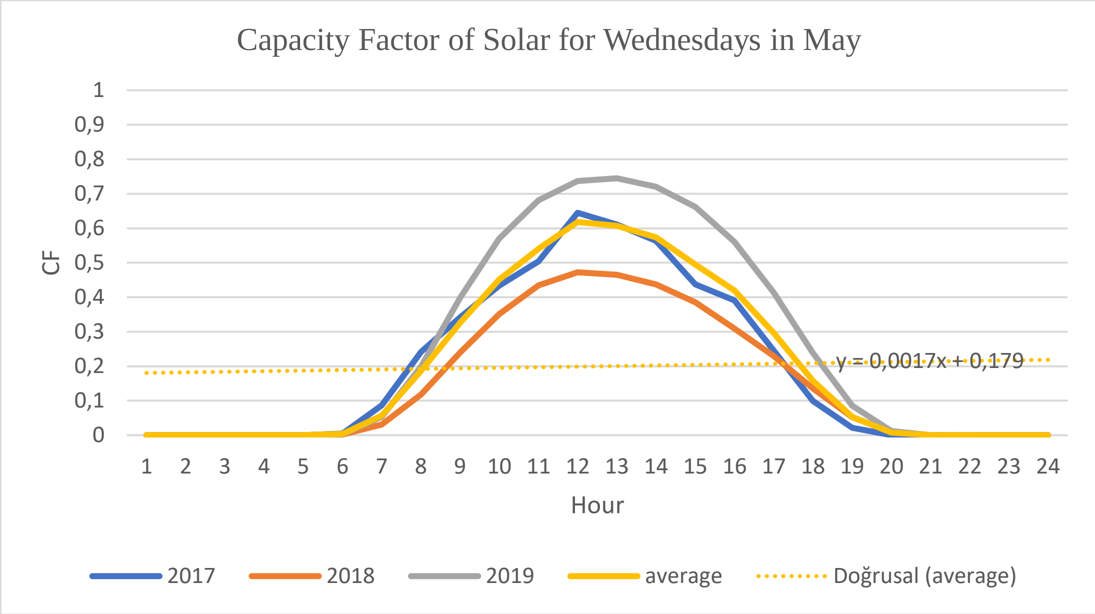

Figure 4.13 Capacity factor of solar for Wednesdays in May between 2017-2019

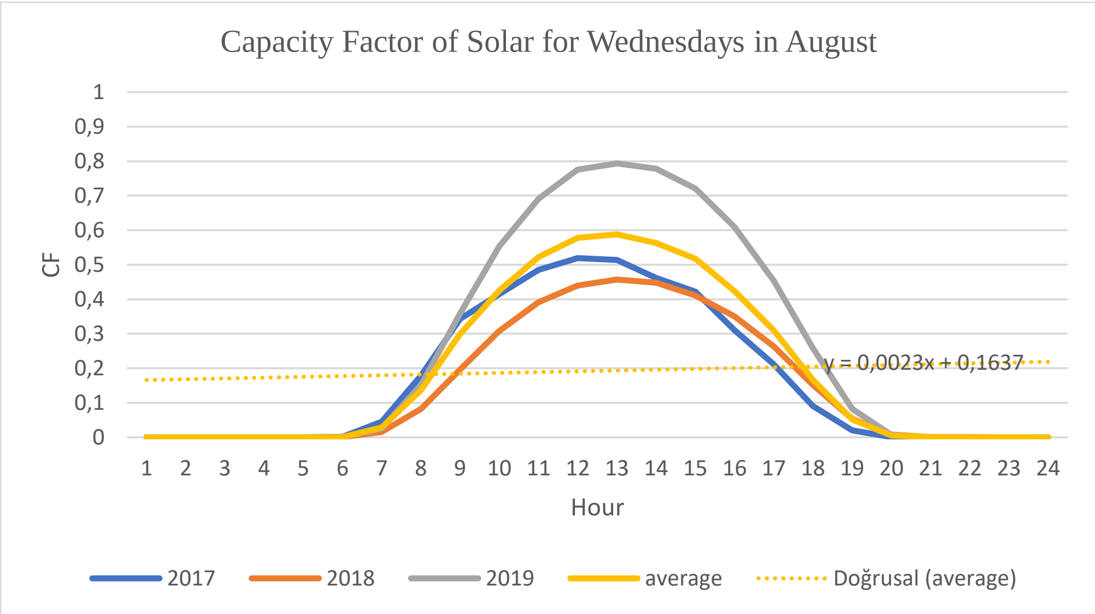

Figure 4.14 Capacity factor of solar for Wednesdays in August between 2017-2019

For future regional wind energy technologies, NASA's MERRA Project's MERRA-2 dataset [24] is obtained over *Renewables.ninja* website, which is the work of Stefan Pfenninger and Iain Staffell [26]. For each province, the hourly electricity production values of Nordex N100 2500 turbine with 1 kW capacity at 80 meters are acquired for 2019. Average capacity factors are calculated for the model's time-slices.

For future regional solar energy technologies, EU Science Hub's SARAH Solar Radiation dataset is used [29]. For each province, the hourly electricity production values at optimal angles are obtained for 2005 and 2016. Average availability factors for each time-slice are calculated.

4.7 Cost and Technical Specifications of Technologies

The cost and technical data for energy supply technologies are obtained from the technology briefs of International Renewable Agency (IRENA) [12]. All costs are included as million US dollars per PJ, and each cost is converted into its 2018 US dollar equivalent. The commodity costs are acquired from World Bank's Commodity Markets Outlook October 2020 [39]. For the government incentive scenarios, the EPDK's announcement of law 3453 about the Turkish Renewable Energy Resources Support Mechanism (YEKDEM) is considered. In this law, the upper limit for YEKDEM subsidy for wind and solar-based energy plants is 5.10 USD cents per kWh [6].

CHAPTER 5

5. SCENARIOS AND RESULTS

In this chapter, the details of scenarios and results are given for the TIMES model. In the model's time horizon between 2018-2030, the year 2018 is used as a calibration year. It includes hourly historical data for consumption and annual historical data for production.

5.1 Reference Scenario and Results

In the reference scenario (SCENREF), no policy constraint or restriction is applied to the model. This is the base scenario where the model decides without any other driver than demand.

The year 2018, the base year, is used to calibrate the model with real data. The difference between real and model data for electricity generation and supply consumption in 2018 can be seen in Table 5.1. All source types have under 13% deviation from real data other than oil. In the sense of gross production, only a 0.2% deviation occurs.

The model's supply consumption amounts in 2018 are compared with real data. Table 5.2 shows the amounts of each supply type consumed in electricity production for model and real data. The coal, lignite and natural gas supply consumptions significantly differ from real data. However, while the total real consumption amount reaches 2154.3 PJ, the deviation is only around 6%. Therefore, their deviations can be acceptable.

The total and individual supply consumption for each period can be seen in Table 5.3. The supply mix shares can be seen in Figure 5.1. The imported coal's share starts at 24% (548 PJ) in 2018 and goes down to 20% (696.3 PJ) in 2030. Natural gas is another supply whose consumption rises while its share decreases. Natural gas loses a 5% share through the model horizon, and its share becomes 23% in 2030. Still, it holds the biggest share in the supply mix except for 2020, where imported coal has the biggest share with 24% (553 PJ). The share of lignite decreases alongside the decrease in consumption amount. Meanwhile, the share of run-of-river decreases slightly, and the share of wind stays the same even with the increase in supply consumption. Akkuyu Nuclear Power Plant's installation increases the nuclear supply share to 6% (200 PJ) in 2030. Solar, hydro, and geothermal are other supply commodities in which consumption amounts and shares increase.

The total and individual electricity production in PJ can be seen in Table 5.4. In 2018, 1090.5 PJ is produced to be supplied to the distribution network in the model. In 2020, with the decrease in real demand, the model’s total electricity production becomes 1074.1 PJ. It starts to increase in 2025 with 1385.2 PJ and ends with 1761.5 PJ in 2030. Figure 5.2 shows the share of supply types in electricity production through the model horizon. Natural gas has the most significant share in electricity production, with 31% in 2018. Its share decreases to 24% in 2030. Despite the decrease, natural gas is the dominant supply type in electricity production at the end of the model horizon. The share of nuclear supply type increases from 0% to 5%. Hydro, from 14% to 17%, solar, from 2% to 13%, and geothermal, from 2% to 4%, are supply types whose electricity production and shares increase. Imported coal and lignite are supply types whose shares decrease. Both decrease more than 5% until the end of the model horizon. Other supply types protect their share in the energy mix through all periods.

The technology capacities are another crucial decision variables that help the decision maker to achieve the proposed system. Table 5.5 shows the total and individual capacities in GW for all types of supplies. All capacity shares can be seen in Figure 5.3. There appears to be a significant decrease in natural gas capacity, from 26.5 GW in 2020 to 15.6 GW in 2025. This decrease happens because half of the existing natural gas power plants fulfill their technical life. The model compensates for this decrease by installing 28.3 GW of new natural gas power plants until 2030. In 2025, hydro has the most significant capacity share with 21%. The total capacity share of renewable energy sources becomes 55%, where 25% is hydro, at the end of the model horizon.

Table 5.1 Comparison of electricity generation in reference scenario and real-life data for 2018

	Model	Real	Difference (%)
Coal	406.0	407.7	-0.4
Oil	2.8	1.2	133.3
Natural Gas	333.6	332.9	0.2
Solid Biofuel	8.3	9.5	-12.7
Hydro and Run-of-River	214.4	215.8	-0.6
Solar	24.4	28.1	-13.0
Geothermal	26.8	26.8	0.2
Wind	74.1	71.0	4.4
Total	1090.5	1093.0	-0.2

Table 5.2 Comparison of supply consumption amount in reference scenario and real-life data for 2018

	Model (PJ)	Real (PJ)	Difference (%)
Asphalt	23.0	22.8	1%
Coal	594.0	508.8	17%
Lignite	432.0	484.8	-11%
Oil	5.0	3.2	56%
Natural Gas	629.4	543.8	16%
Solid Biofuel	17.6	17.2	3%
Hydro and Run-of-River	214.4	212.0	1%
Solar	24.4	22.8	7%
Geothermal	268.0	267.5	0%
Wind	74.1	71.5	4%
Total	2282.0	2154.3	6%

Table 5.3 Supply consumption amounts in PJ for reference scenario

	2018	2020	2025	2030
Asphalt	23.0	23.2	23.5	23.7
Imported Coal	548.0	553.0	630.6	696.3
Lignite	432.0	370.0	384.9	400.5
Steam Coal	46.0	48.9	54.0	59.6
Solid Bio Fuel	17.6	29.3	16.3	7.9
LNG	0.0	1.0	0.0	5.0
Natural Gas	629.4	466.0	639.6	800.0
Nuclear	0.0	0.0	137.4	200.0
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	5.0	1.7	3.3	3.7
Naphtha	0.0	0.2	0.0	0.0
Geothermal	268.0	381.9	329.2	630.8
Hydro	148.3	210.7	185.2	300.3
Run-of-river	66.2	68.3	71.8	75.5
Solar	24.4	30.6	153.2	229.7
Wind	74.1	88.6	111.2	114.9
Total	2282.0	2273.6	2740.3	3547.8

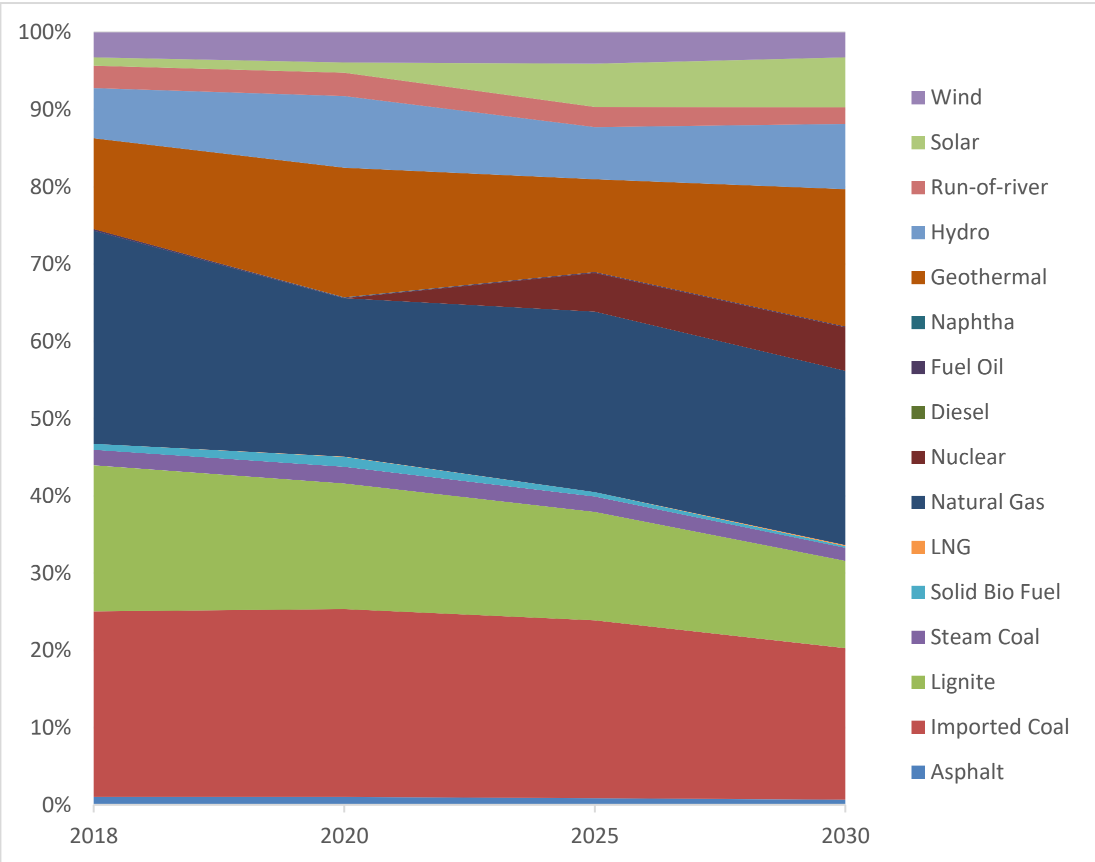

Figure 5.1 Supply consumption shares in percentage for reference scenario

Table 5.4 Electricity production amounts in PJ for reference scenario

	2018	2020	2025	2030
Asphalt	8.0	8.1	8.2	8.3
Imported Coal	224.4	215.5	253.6	278.3
Lignite	161.4	138.3	141.1	149.8
Steam Coal	12.2	13.6	18.9	20.9
Solid Bio Fuel	8.3	13.3	6.7	2.8
LNG	0.0	0.0	0.0	0.0
Natural Gas	333.6	247.5	339.0	426.6
Nuclear	0.0	0.0	61.8	90.0
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	2.8	1.1	1.4	1.4
Naphtha	0.0	0.1	0.0	0.0
Geothermal	26.8	38.2	32.9	63.1
Hydro	148.3	210.7	185.2	300.3
Run-of-river	66.2	68.3	71.8	75.5
Solar	24.4	30.6	153.2	229.7
Wind	74.1	88.6	111.2	114.9
Total	1090.5	1074.1	1385.2	1761.5

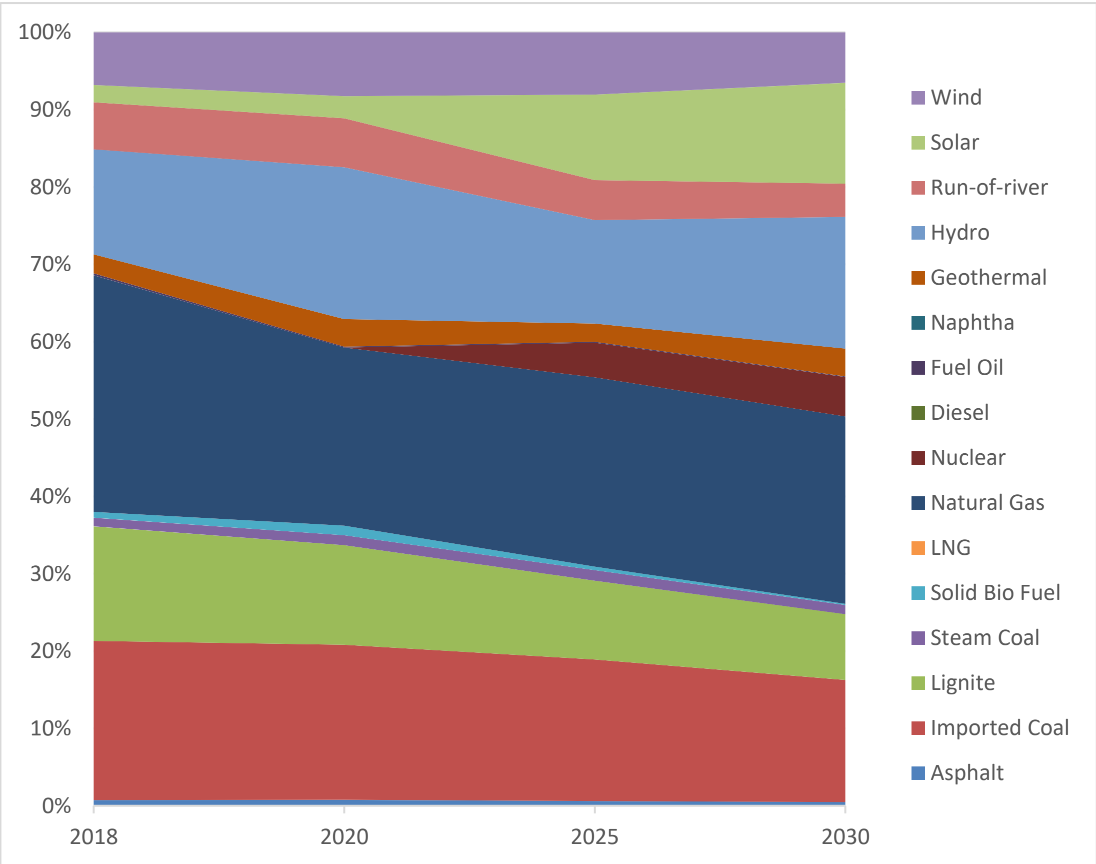

Figure 5.2 Electricity production shares in percentage for reference scenario

The model calculates electricity prices on an hourly basis. The price differs within hours, whereas in peak times, they may increase immensely. Table 5.6 shows the average monthly and annual electricity prices. 2020 has the greatest average annual price. The average monthly price is generally lower in March and April and higher in January, February, November, and December for each milestone year.
The total carbon dioxide emission is around 102 Mton in 2018 and increases to 353 Mton in 2030. As there is no tax or subsidy in the reference scenario, the cost of the system only depends on related technologies, their investment and operation costs, and flow costs.

Table 5.5 Technology capacities in GW for reference scenario

	2018	**2020**	**2025**	**2030**
Asphalt	0.4	0.4	0.4	0.4
Imported Coal	9.2	8.3	14.9	12.4
Lignite	9.5	10.0	9.9	8.1
Steam Coal	0.4	0.5	7.7	7.5
Solid Bio Fuel	0.7	0.8	0.6	0.2
LNG	0.0	0.0	0.0	0.0
Natural Gas	25.9	26.5	15.6	28.3
Nuclear	0.0	0.0	2.4	3.6
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	0.6	0.5	1.2	1.0
Naphtha	0.0	0.0	0.0	0.0
Geothermal	1.9	2.0	1.3	2.6
Hydro	20.5	23.4	20.8	33.8
Run-of-river	7.7	7.7	7.4	7.9
Solar	5.1	5.1	12.8	23.9
Wind	7.0	8.0	6.3	6.5
Total	88.8	93.2	101.3	136.3

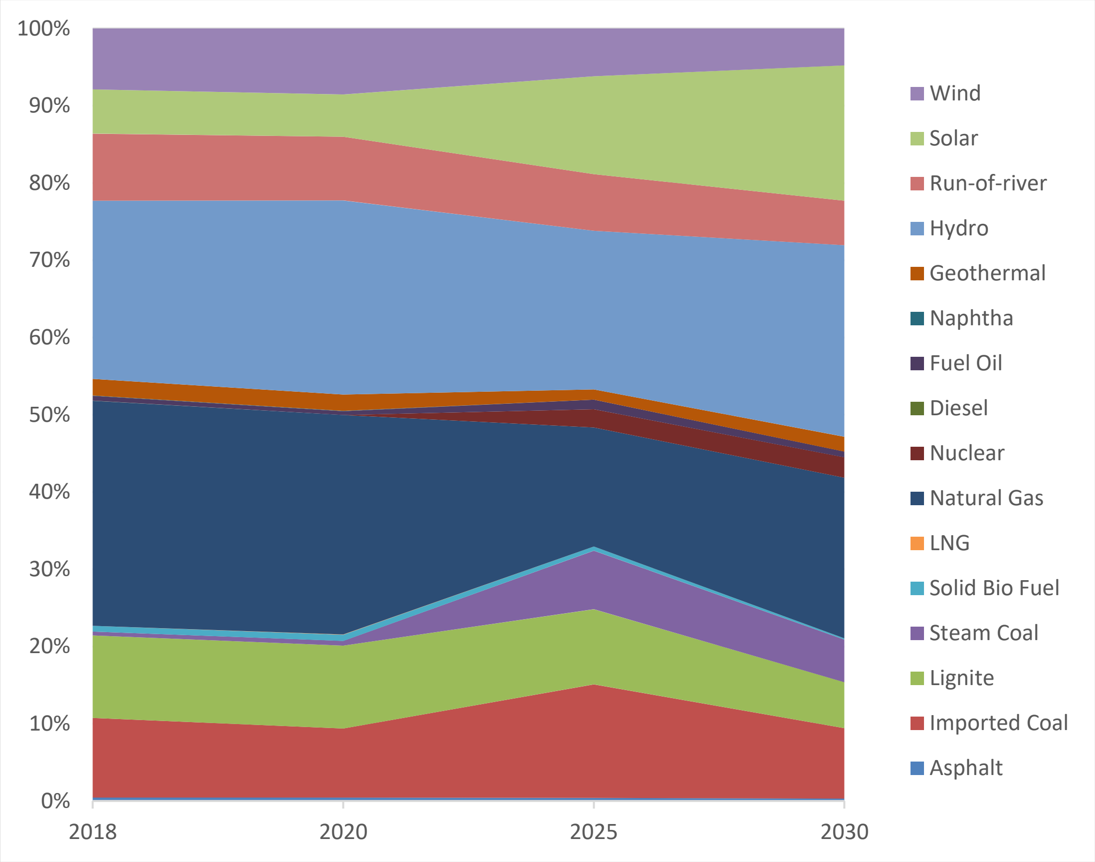

Figure 5.3 Technology capacity shares for reference scenario

Table 5.6 Average monthly and yearly electricity prices of reference scenario ($/MWh)

SCENREF	2018	2020	2025	2030
January	20.4	72.5	20.0	43.9
February	20.1	87.3	19.6	39.3
March	17.0	34.3	16.3	33.3
April	18.5	35.0	17.0	31.2
May	20.3	79.3	21.4	40.5
June	19.9	65.4	18.1	31.2
July	19.2	69.7	20.2	36.3
August	16.9	64.7	20.9	36.9
September	19.0	67.5	21.6	36.9
October	20.4	97.0	22.9	38.8
November	19.4	102.6	25.0	42.3
December	20.5	114.1	308.0	113.2
Average	19.3	74.1	44.2	43.6

5.2 Regional Scenarios and Results

The regional scenarios include solar and wind technologies with capacity amounts and factors implemented according to their provinces. The solar regional scenario includes 81 provinces for solar technologies that can be used in and after 2025. Similarly, the wind regional scenario includes 69 provinces for wind technologies that can be used in and after 2025.

5.2.1 Solar Regional Scenario

In the solar regional scenario (SCENSOL), all technologies for solar supply type after 2020 are regional without any government incentive. This application of solar technologies brings the regional capacity factors that may affect the model's behavior.

Table 5.7 shows the individual and total supply consumption for each supply type. The supply mix shares can be seen in Figure 5.4. Except for a decrease in hydro supply consumption and an increase in solar supply consumption in 2030, the supply consumption amounts, and shares follow the same behavior as the reference model. The solar supply share increases from 1% (24.6 PJ) in 2018 to 9% (305.0 PJ) in 2030, and the hydro share decrease from 7% (148.3 PJ) in 2018 to 6% in 2030 (208.9 PJ). The shares of imported coal and natural gas decrease despite the increase in consumption amounts. The share of lignite decreases significantly. The shares of nuclear and geothermal increase by 6% until the end of the model horizon.

The total and individual electricity production amounts in PJ can be seen in Table 5.8. The production amount and share are the same as the reference scenario in 2018, which is expected as 2018 is the calibration period. In Figure 5.5, the shares of supply types in electricity production can be seen. Like the supply consumption, the amount of electricity produced by hydropower plants increases by almost 61 PJ. Yet, its share in electricity production decreases from 14% in 2018 to 12% in 2030. The electricity produced by solar power plants increases by almost 280 PJ from 2018 to 2030, which is higher than the reference scenario. The highest production happens in solar power plants in Konya. In 2030, 17% of total produced electricity is supplied by solar power plants. This share is higher than shares of other supply types except for natural gas, which still has the highest share at 24%. The total share of renewable energy sources becomes 44% at the end of the model horizon.

Table 5.7 Supply consumption amounts in PJ for solar regional scenario

	2018	2020	2025	2030
Asphalt	23.0	23.2	23.5	23.7
Imported Coal	548.0	553.0	630.6	696.3
Lignite	432.0	370.0	384.9	400.5
Steam Coal	46.0	45.1	54.0	59.6
Solid Bio Fuel	17.6	29.2	16.3	7.9
LNG	0.0	1.0	0.0	5.0
Natural Gas	626.8	466.0	568.3	800.0
Nuclear	0.0	0.0	139.2	200.0
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	5.0	1.5	0.7	3.7
Naphtha	0.0	0.2	0.0	0.0
Geothermal	268.0	295.1	207.8	630.8
Hydro	148.3	210.6	184.4	208.9
Run-of-river	66.2	68.3	71.8	75.5
Solar	24.6	38.9	195.9	305.0
Wind	74.1	88.6	111.0	114.6
Total	2279.8	2190.8	2588.5	3531.5

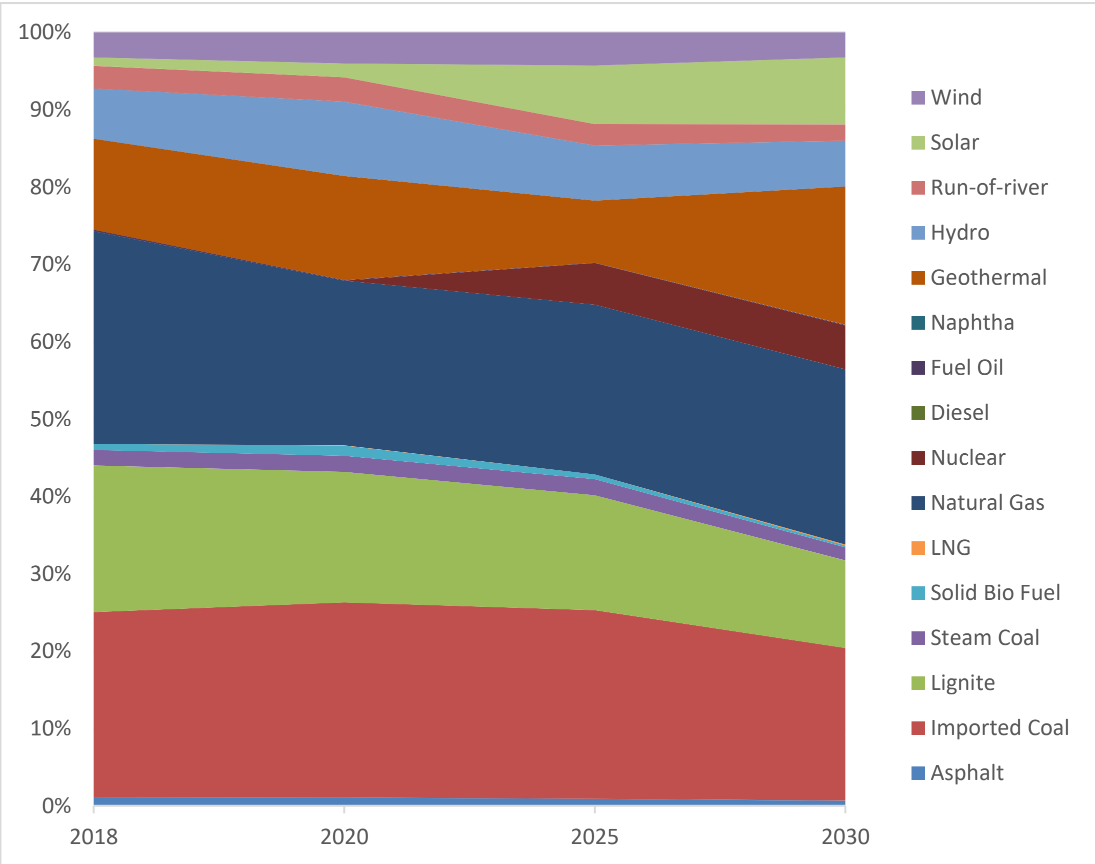

Figure 5.4 Supply consumption shares for solar regional scenario

Table 5.8 Electricity production amounts in PJ for solar regional scenario

	2018	2020	2025	2030
Asphalt	8.0	8.1	8.2	8.3
Imported Coal	224.7	214.5	253.9	278.5
Lignite	161.4	138.3	141.2	151.8
Steam Coal	12.3	12.3	18.9	20.9
Solid Bio Fuel	8.3	13.3	6.7	2.8
LNG	0.0	0.0	0.0	0.0
Natural Gas	332.2	247.5	301.2	426.7
Nuclear	0.0	0.0	62.6	90.0
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	2.8	1.0	0.4	1.4
Naphtha	0.0	0.1	0.0	0.0
Geothermal	26.8	29.5	20.8	63.1
Hydro	148.3	210.6	184.4	208.9
Run-of-river	66.2	68.3	71.8	75.5
Solar	24.6	38.9	195.9	305.0
Wind	74.1	88.6	111.0	114.6
Total	1089.8	1071.0	1377.2	1747.4

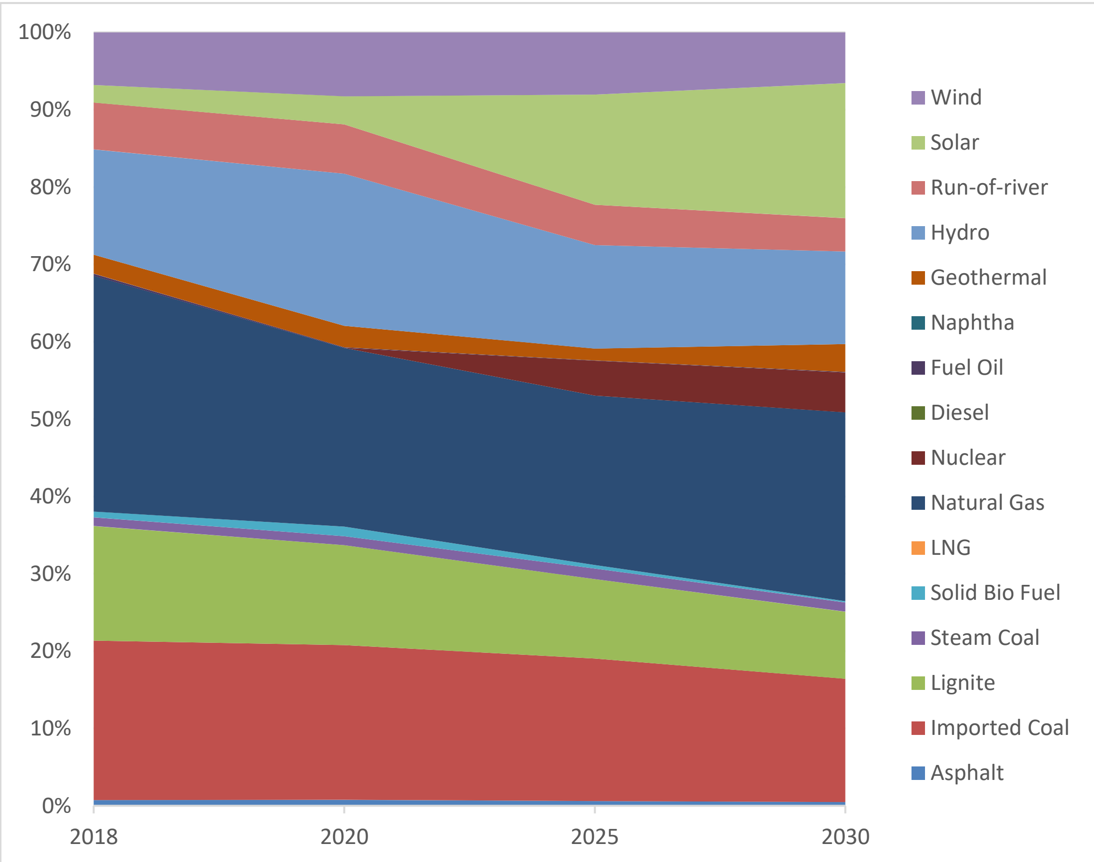

Figure 5.5 Electricity production ratios for solar regional scenario

Table 5.9 Technology capacities in GW for solar regional scenario

	2018	2020	2025	2030
Asphalt	0.4	0.4	0.4	0.4
Imported Coal	9.2	8.3	14.5	13.4
Lignite	9.5	10.0	9.4	9.2
Steam Coal	0.4	0.4	8.5	8.4
Solid Bio Fuel	0.7	0.8	0.6	0.2
LNG	0.0	0.0	0.0	0.0
Natural Gas	25.9	26.5	15.6	28.6
Nuclear	0.0	0.0	2.4	3.6
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	0.6	0.5	1.2	1.0
Naphtha	0.0	0.0	0.0	0.0
Geothermal	1.5	1.6	0.9	3.0
Hydro	20.5	23.4	20.8	23.6
Run-of-river	7.7	7.7	7.6	8.0
Solar	7.5	9.0	16.5	29.3
Wind	7.0	8.0	6.3	6.5
Total	90.9	96.6	104.9	135.3

Table 5.9 and Figure 5.6 show the details of technology capacities both in GW and percentage shares. The significant changes happen in the capacity of solar and hydropower plants in contrast to the reference scenario. In the solar regional scenario, the share of solar capacity becomes the highest among all supply types with 22%. The natural gas share follows with 21% and hydro with 17%. Konya becomes the first province with 1.8 GW installed solar capacity, and Van is second with 1.1 GW. The model chooses to invest in solar power plants in all 81 provinces. The total capacity share of renewable energy sources becomes 52%.

Table 5.10 shows the average monthly and annual electricity prices. Even though the demand pattern is the same as the reference scenario, the highest average annual price occurs in 2030. The average monthly price is generally lower in March, April, and June and increases in November and December. According to the reference scenario, the average price in 2020 is decreased by 63% in the solar regional scenario.

The solar capacity and electricity production values are higher than the reference scenario. A difference in historical and theoretical capacity factors can be the reason. As the theoretical capacity factors are calculated for each province separately, the model can choose to invest more in specific provinces without increasing the total system cost.

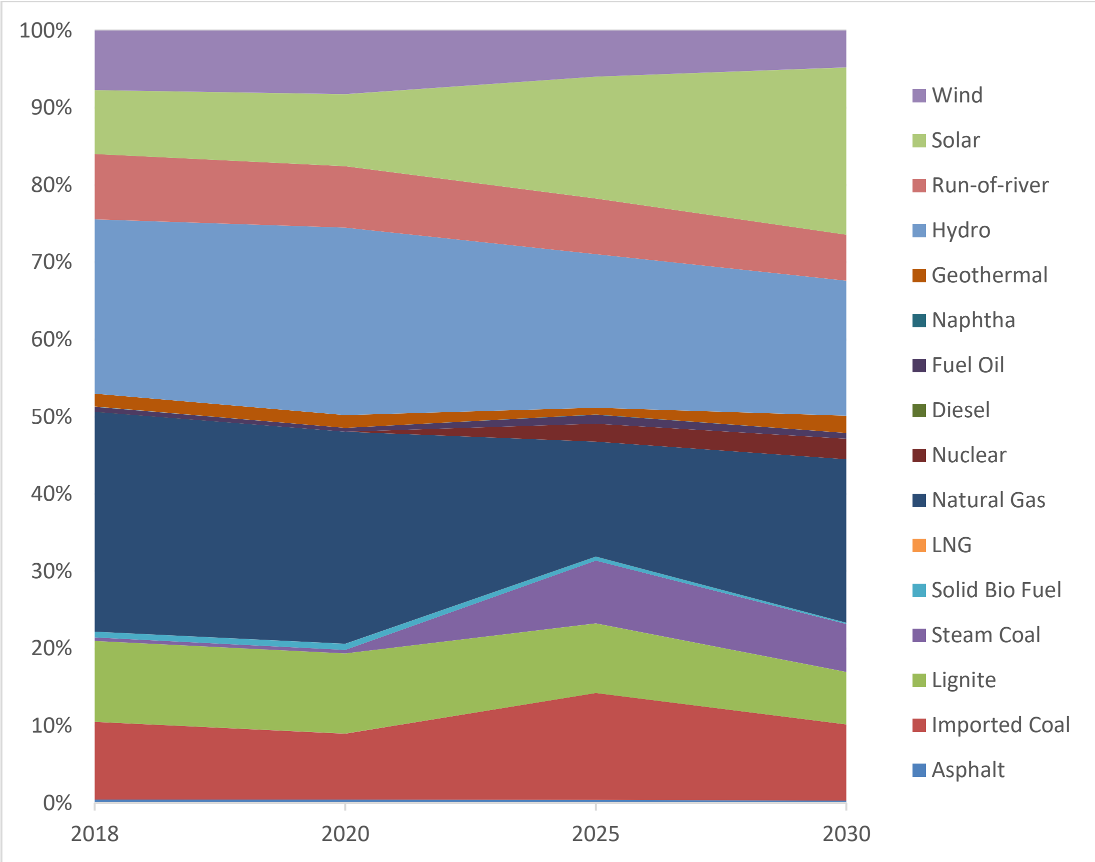

Figure 5.6 Technology capacity ratios for solar regional scenario

Table 5.10 Average monthly and yearly electricity prices of solar regional scenario ($/MWh)

SCENSOL	2018	2020	2025	2030
January	20.7	22.9	17.7	35.9
February	20.3	29.2	17.0	34.8
March	17.6	18.0	13.9	29.8
April	18.6	17.4	14.0	30.1
May	20.5	29.8	21.0	35.2
June	20.1	21.3	15.5	26.8
July	19.5	20.7	19.7	29.4
August	16.9	22.0	20.5	32.3
September	19.2	25.0	20.7	32.6
October	20.5	36.8	22.4	34.9
November	19.7	40.2	23.7	38.2
December	20.8	46.4	277.9	161.4
Average	19.5	27.5	40.3	43.5

There are significant changes in the total carbon dioxide emissions in 2020 and 2025. It decreases by 2% in 2020 and 5% in 2025 compared to the reference scenario. This is primarily the result of an increase in the capacity of the solar power plants.

There is no tax or subsidy in the solar regional scenario. Therefore, the system cost depends on similar variables as the reference scenario. The total cost of system has no significant difference from the reference scenario.

5.2.2 Wind Regional Scenario

In the wind regional scenario (SCENWND), all technologies for wind supply type after 2020 are regional without any government incentive. This model can decide to invest in wind power plants in distinct provinces after 2020.

Table 5.11 Supply consumption amounts in PJ for wind regional scenario

	2018	**2020**	**2025**	**2030**
Asphalt	23.0	23.2	23.5	23.7
Imported Coal	548.0	553.0	630.6	696.3
Lignite	432.0	370.0	384.9	400.5
Steam Coal	46.0	48.9	54.0	59.6
Solid Bio Fuel	17.6	29.3	16.3	7.9
LNG	0.0	1.0	0.0	5.0
Natural Gas	629.4	466.0	629.9	800.0
Nuclear	0.0	0.0	138.2	200.0
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	5.0	1.7	3.3	3.7
Naphtha	0.0	0.0	0.0	0.0
Geothermal	268.0	381.9	322.2	630.8
Hydro	148.3	210.7	185.1	311.0
Run-of-river	66.2	68.3	71.8	75.5
Solar	24.4	30.6	164.4	229.6
Wind	74.1	88.6	103.6	103.6
Total	2282.0	2273.3	2727.7	3547.2

Table 5.11 shows the individual and total supply consumption for each supply. The consumption shares can be seen in Figure 5.7. There is no significant change in supply consumption ratios compared to the reference scenario. The total supply shares of renewable energy sources for each milestone year are the same as the reference scenario. There is a slight increase in the consumption of hydro supply and a decrease in the consumption of wind supply in the years 2025 and 2030 compared to SCENREF

scenario.

The total and individual electricity production amounts in PJ can be seen in Table 5.12. The production amounts and shares are almost the same as the reference scenario for each year. There are insignificant changes in electricity production from hydro and solar power plants in 2025 and 2030. In Figure 5.8, the shares of supply types in electricity production can be seen. The highest electricity productions from wind supply occur in Çanakkale (16.4 PJ), Aydın (15.7 PJ), and İzmir (15.4 PJ). These three provinces have the highest availability of wind supply throughout all months. The total share of electricity produced by renewable energy sources stays the same as the reference scenario.

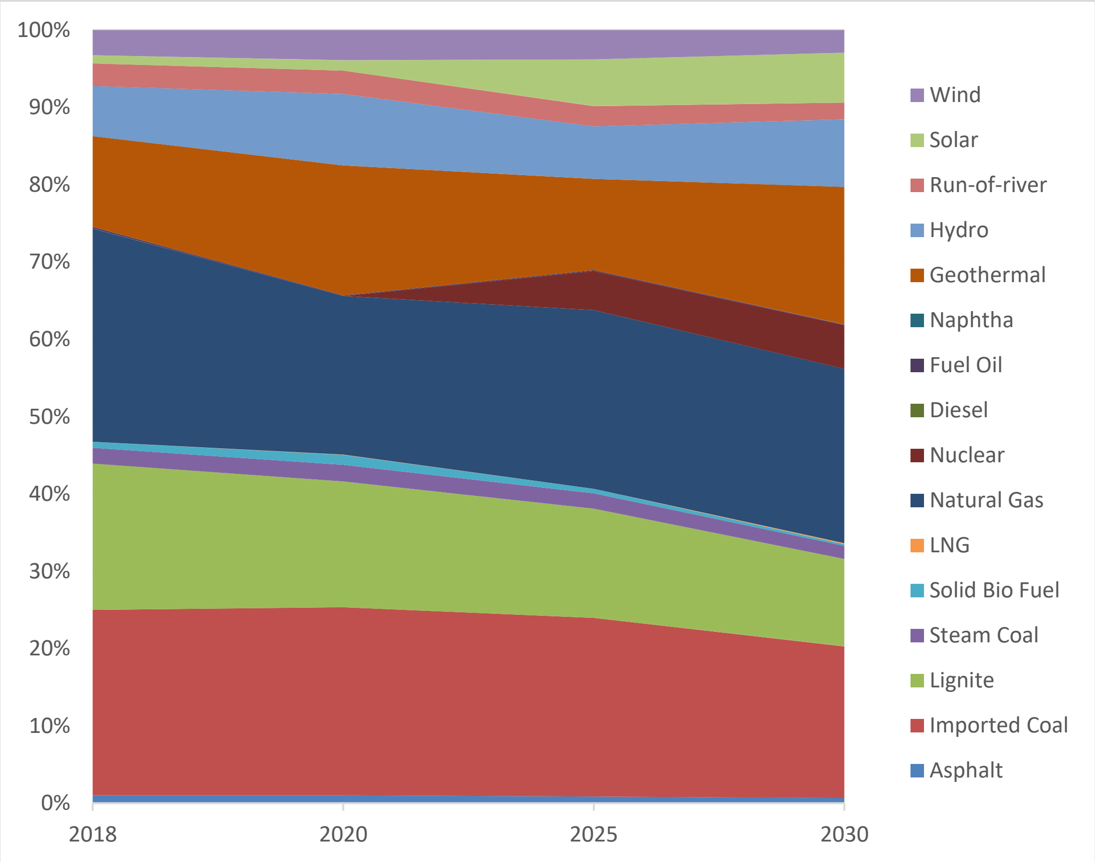

Figure 5.7 Supply consumption ratios for wind regional scenario

Table 5.12 Electricity production amounts in PJ for wind regional scenario

	2018	2020	2025	2030
Asphalt	8.0	8.1	8.2	8.3
Imported Coal	224.6	215.5	253.7	278.3
Lignite	161.4	138.3	141.1	150.4
Steam Coal	12.1	13.6	18.9	20.9
Solid Bio Fuel	8.3	13.3	6.7	2.8
LNG	0.0	0.0	0.0	0.0
Natural Gas	333.6	247.5	333.8	426.7
Nuclear	0.0	0.0	62.2	90.0
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	2.8	1.1	1.4	1.4
Naphtha	0.0	0.1	0.0	0.0
Geothermal	26.8	38.2	32.2	63.1
Hydro	148.3	210.7	185.1	311.0
Run-of-river	66.2	68.3	71.8	75.5
Solar	24.4	30.6	164.4	229.6
Wind	74.1	88.6	103.6	103.6
Total	1090.5	1074.1	1383.1	1761.5

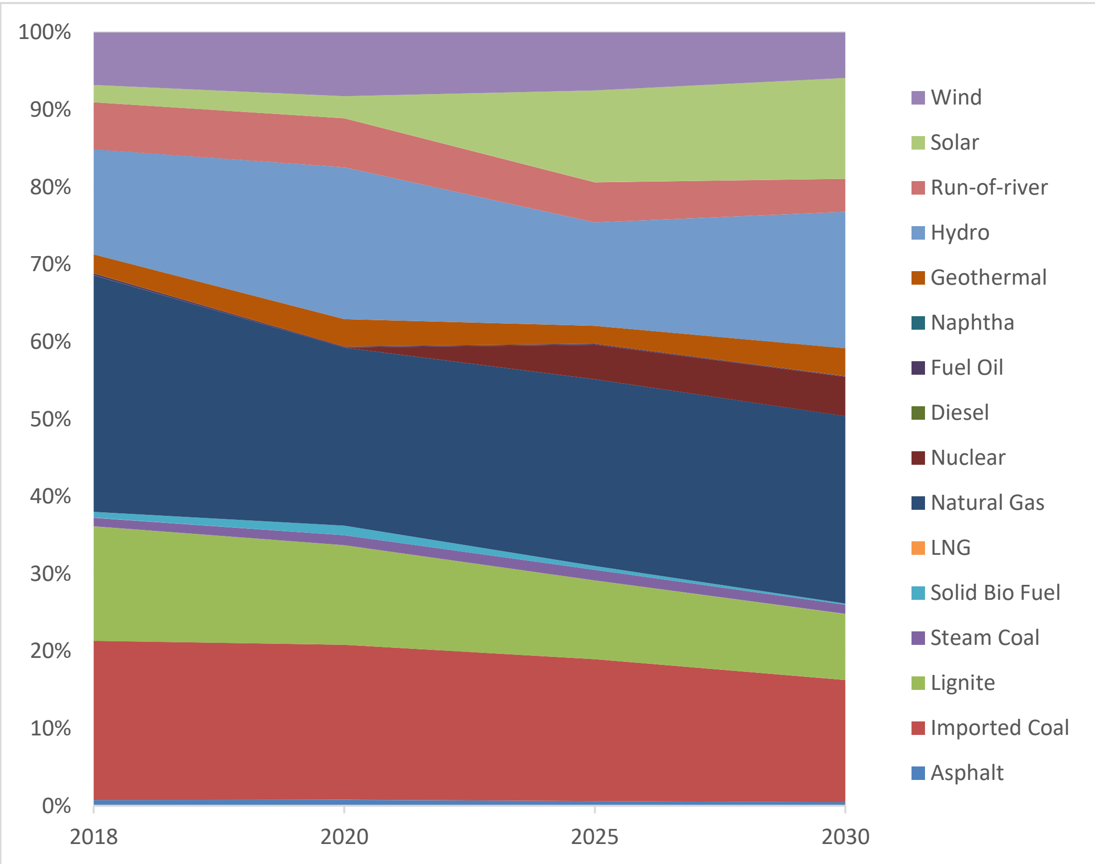

Figure 5.8 Electricity production ratios for wind regional scenario

Table 5.13 Technology capacities in GW for wind regional scenario

	2018	2020	2025	2030
Asphalt	0.4	0.4	0.4	0.4
Imported Coal	9.2	8.3	14.8	12.4
Lignite	9.5	10.0	9.6	8.1
Steam Coal	0.4	0.5	8.4	8.3
Solid Bio Fuel	0.7	0.8	0.6	0.2
LNG	0.0	0.0	0.0	0.0
Natural Gas	25.9	26.5	15.6	27.9
Nuclear	0.0	0.0	2.4	3.6
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	0.6	0.5	1.2	1.0
Naphtha	0.0	0.0	0.0	0.0
Geothermal	1.9	2.0	1.3	2.6
Hydro	20.5	23.4	20.8	35.0
Run-of-river	7.7	7.7	7.5	7.9
Solar	5.1	5.1	14.3	24.2
Wind	7.0	7.0	8.5	8.5
Total	88.8	92.3	105.5	140.1

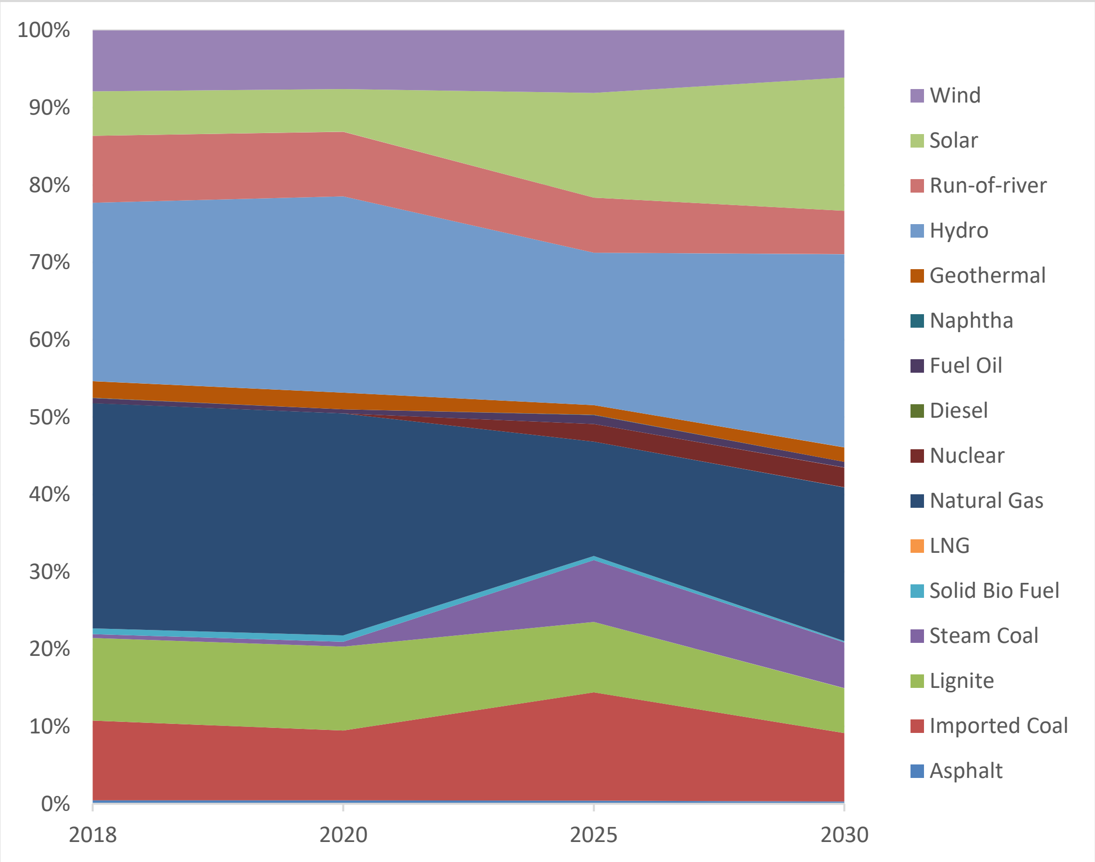

Figure 5.9 Technology capacity ratios for wind regional scenario

Table 5.13 and Figure 5.9 show the details of technology capacities both in GW and percentage shares. The total capacity of wind power plants increases in this scenario by 4.2 GW in 2025 and 3.8 GW in 2030 compared to SCENREF scenario. Around 2 GW of these increases happens with the increase in the capacity of wind power plants. The implementation of regional capacity factors leads the model to increase the total capacity of wind power plants. However, the electricity production decreases. Çanakkale, Aydın, and İzmir provinces have the highest capacities, around 1 GW each. The total capacity of renewable-energy power plants increases to 78.2 GW compared to the reference scenario. This increase is around 1% and does not have significance.

Table 5.14 shows the average monthly and annual electricity prices. The only significant change in electricity prices occurs in 2025 when the average annual price increases by 8% compared to the reference scenario. December has the highest and March has the lowest average electricity prices as same as the reference and solar regional scenarios.

In this scenario, the total capacity of wind power plants is higher than SCENREF scenario. But their electricity production and supply consumption are less. There is no significant change in the total carbon dioxide emissions or system cost.

Table 5.14 Average monthly and yearly electricity prices of wind regional scenario ($/MWh)

SCENWND	2018	2020	2025	2030
January	20.4	73.1	22.2	43.1
February	20.1	88.0	21.7	39.2
March	17.0	34.6	17.7	33.2
April	18.5	35.3	17.8	31.1
May	20.3	79.9	25.9	40.4
June	19.9	65.9	21.8	31.4
July	19.2	70.2	25.4	37.1
August	16.9	65.2	25.9	36.6
September	19.0	68.0	25.5	36.7
October	20.4	97.7	27.7	39.4
November	19.4	103.4	29.9	42.4
December	20.5	115.0	313.3	113.3
Average	19.3	74.7	47.9	43.7

5.3 Government Incentive Scenarios and Results

For the government incentive scenarios, YEKDEM is applied. According to law no:5346, the government provides feed-in-tariffs for the renewable energy sources used to generate electricity. The government attempts to increase the renewable energy shares in electricity production with the help of this support mechanism. Law no:3453, which was issued in 2021, adjusts the feed-in-tariffs. This law is included in government incentive scenarios. The upper limit that can be paid for each kWh of electricity produced by wind and solar power plants is decided as 5.10 USD cents by law no:3453. [6] A regional solar or wind power plant can benefit from this support after 2020 until 2030 in both scenarios.

5.3.1 Solar Regional with Government Incentive Scenario

In the solar regional with government incentive scenario (SCENSOLYEK), all technologies for solar supply type after 2020 are regional with government incentive, YEKDEM.

Table 5.15 Supply consumption amounts in PJ for solar regional with government incentive scenario

	2018	2020	2025	2030
Asphalt	23.0	23.2	23.5	23.7
Imported Coal	548.0	553.0	630.6	696.3
Lignite	432.0	370.0	384.9	400.5
Steam Coal	46.0	45.1	54.0	59.6
Solid Bio Fuel	17.6	28.8	16.2	7.9
LNG	0.0	0.0	0.0	5.0
Natural Gas	626.8	462.6	566.6	800.0
Nuclear	0.0	0.0	135.5	200.0
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	5.0	1.0	0.6	3.7
Naphtha	0.0	0.0	0.0	0.0
Geothermal	268.0	286.7	202.9	630.8
Hydro	148.3	210.5	184.2	208.2
Run-of-river	66.2	68.3	48.1	75.5
Solar	24.6	49.6	258.2	360.9
Wind	74.1	88.6	111.0	114.6
Total	2279.8	2187.5	2616.3	3586.7

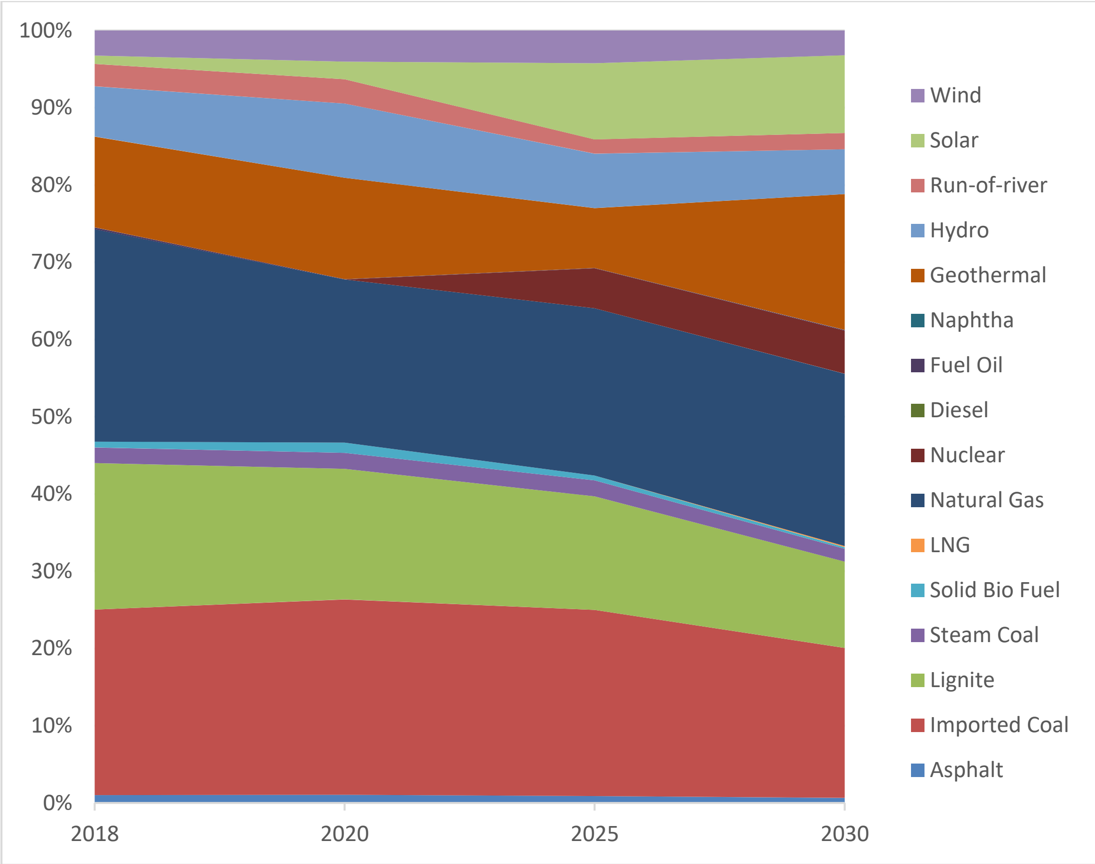

Figure 5.10 Supply consumption ratios for solar regional with government incentive scenario

Table 5.15 shows the individual and total supply consumption for each supply type. The supply mix shares can be seen in Figure 5.10. The solar supply consumption share has the highest increase from 1% in 2018 to 10% in 2030. While the share of imported coal, natural gas, and hydro decreases, others remain the same. The consumption amount of solar supply is higher than SCENREF scenario by 131.2 PJ in 2030. However, the total consumption share of renewable energy sources does not differ significantly in SCENSOLYEK (39%) scenario compared to SCENREF (38%) scenario at the end of the model horizon.

Table 5.16 shows the total, and individual electricity production amounts in PJ for each milestone year. There are 2% increases in the total electricity production in 2025 and 2030 compared to SCENREF scenario. The primary reason for this increase appears to be the solar power plants. Figure 5.11 shows the shares of supply types in electricity production. With the increase in capacity, the electricity produced by solar power plants increases from 24.6 PJ (2%) in 2018 to 360.9 PJ (20%) in 2030. In

SCENREF scenario, the solar supply share in electricity production is the fourth highest share. However, in SCENSOLYEK scenario, it becomes the second highest share after natural gas, which is 24%. The highest electricity production happens in Konya province by 20.3 PJ in 2025 and in Antalya by 25.2 PJ in 2030. The total share of renewable energy sources is 46% which is higher than the share of 44% in SCENREF scenario.

Table 5.16 Electricity production amounts in PJ for solar regional with government incentive scenario

	2018	**2020**	**2025**	**2030**
Asphalt	8.0	8.1	8.2	8.3
Imported Coal	224.7	210.6	254.0	278.5
Lignite	161.4	138.3	141.7	152.9
Steam Coal	12.3	11.8	18.9	20.9
Solid Bio Fuel	8.3	13.1	6.7	2.8
LNG	0.0	0.0	0.0	0.0
Natural Gas	332.2	245.2	300.3	426.7
Nuclear	0.0	0.0	61.0	90.0
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	2.8	0.7	0.4	1.4
Naphtha	0.0	0.0	0.0	0.0
Geothermal	26.8	28.7	20.3	63.1
Hydro	148.3	210.5	184.2	208.2
Run-of-river	66.2	68.3	48.1	75.5
Solar	24.6	49.6	258.2	360.9
Wind	74.1	88.6	111.0	114.6
Total	1089.8	1073.5	1412.9	1803.7

Table 5.17 and Figure 5.12 show the details of technology capacities both in GW and percentage shares. The most significant changes happen in the capacities of imported coal, natural gas, and solar power plants compared to SCENREF scenario. The total capacity of solar power plants increases to 37.4 GW in 2030, with the highest share of 26%. The applied government support mechanism (YEKDEM) leads to a tremendous increase in the capacity of the solar power plants. Unlike SCENSOL scenario, Antalya becomes the first province with 2.1 GW, and Konya is the second with 1.9 GW installed capacity of solar power plants.

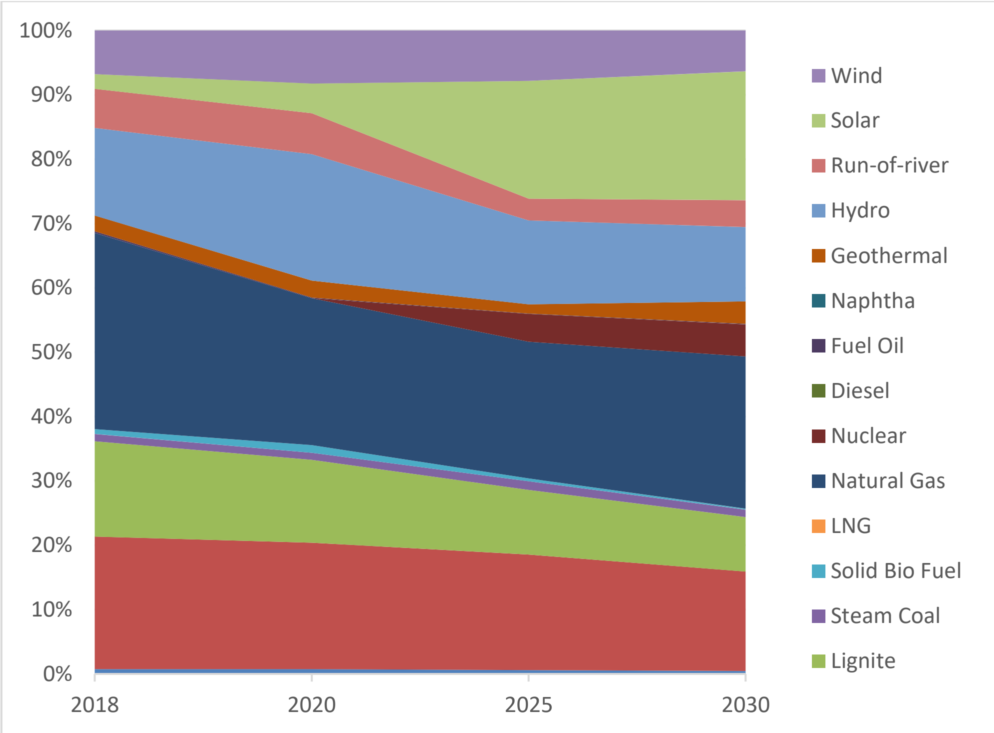

Figure 5.11 Electricity production ratios for solar regional with government incentive scenario

Table 5.17 Technology capacities in GW for solar regional with government incentive scenario

	2018	2020	2025	2030
Asphalt	0.4	0.4	0.4	0.4
Imported Coal	9.2	8.3	13.3	13.3
Lignite	9.5	10.0	8.9	9.3
Steam Coal	0.4	0.4	10.3	10.1
Solid Bio Fuel	0.7	0.8	0.6	0.2
LNG	0.0	0.0	0.0	0.0
Natural Gas	25.9	26.5	15.6	26.9
Nuclear	0.0	0.0	2.4	3.6
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	0.6	0.5	1.2	1.0
Naphtha	0.0	0.0	0.0	0.0
Geothermal	1.5	1.6	0.9	3.1
Hydro	20.5	23.4	20.8	23.6
Run-of-river	7.7	7.7	5.1	8.1
Solar	5.6	9.0	23.4	37.4
Wind	7.0	8.0	6.3	6.5
Total	89.0	96.5	109.2	143.4

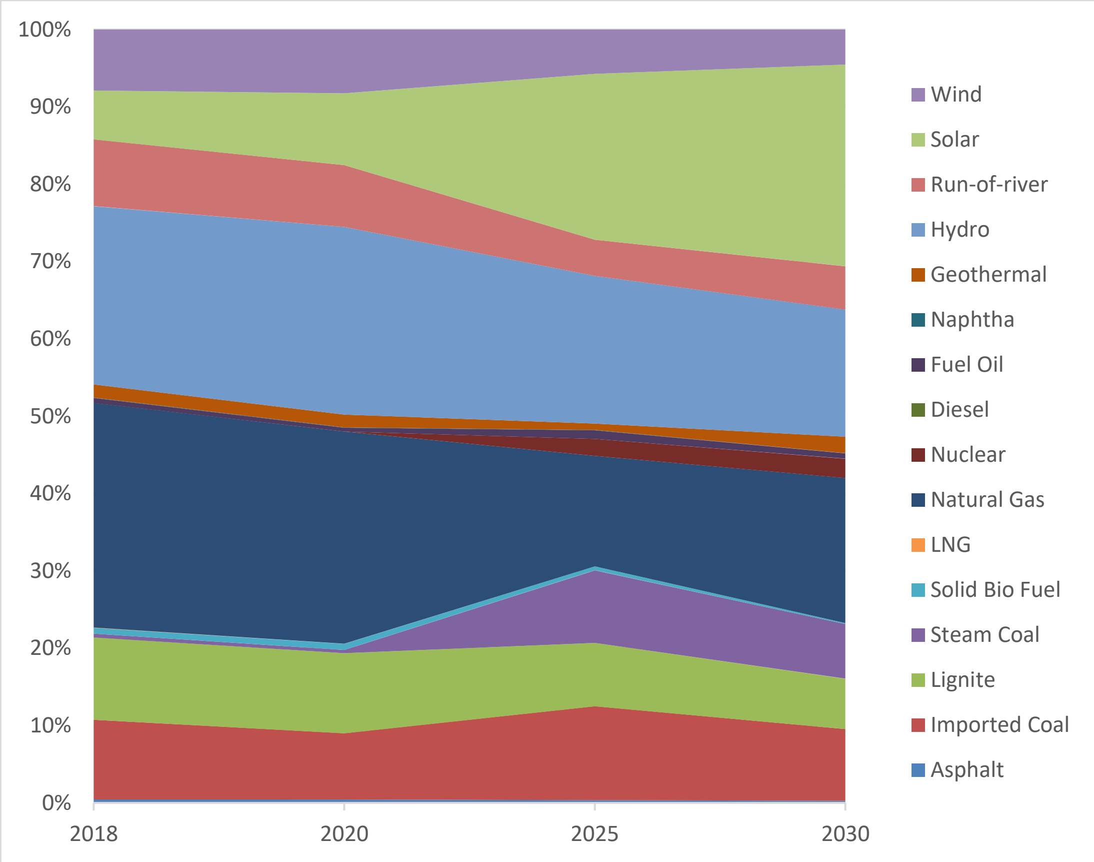

Figure 5.12 Technology capacity ratios for solar regional with government incentive scenario

Table 5.18 Average monthly and yearly electricity prices of solar regional with government incentive scenario ($/MWh)

SCENSOLYEK	2018	2020	2025	2030
January	20.7	8.0	22.3	66.4
February	20.3	8.3	21.4	65.8
March	17.6	8.4	22.4	68.4
April	18.6	6.2	20.6	65.8
May	20.5	7.4	19.3	59.2
June	20.1	6.7	19.9	66.6
July	19.5	6.4	21.2	65.2
August	16.9	6.9	21.3	66.0
September	19.2	7.7	21.8	65.0
October	20.5	9.6	20.8	65.3
November	19.7	10.4	21.7	65.2
December	20.8	11.6	314.0	298.1
Average	19.5	8.2	45.5	84.8

Table 5.18 shows the average monthly and annual electricity prices for SCENSOLYEK scenario. The average yearly price is lower than SCENREF scenario by 89% in 2020 and higher by 94% in 2030. The lowest average monthly prices shift from March, April, and August in 2018 to May at the end of the model horizon.
There is a significant change in the total carbon dioxide emissions in 2020 by 4% and in 2025 by 8% compared to SCENREF scenario. This decrease in emissions results from a significant increase in capacities and electricity production of solar power plants. The SCENSOLYEK scenario includes YEKDEM cost, which shows the amount of feed-in-tariff payments. The model excludes the YEKDEM costs from the system costs. The total subsidy and system costs do not differ significantly from the SCENREF scenario's cost. Therefore, emission mitigation is done without significantly increasing the total system cost.

5.3.2 Wind Regional with Government Incentive Scenario

In the wind regional with government incentive scenario (SCENWNDYEK), all technologies for wind supply type after 2020 are regional with government incentive YEKDEM.

Table 5.19 Supply consumption amounts in PJ for wind regional with government incentive scenario

	2018	**2020**	**2025**	**2030**
Asphalt	23.0	23.2	23.5	23.7
Imported Coal	548.0	553.0	630.6	696.3
Lignite	432.0	370.0	384.9	400.5
Steam Coal	46.0	48.9	54.0	59.6
Solid Bio Fuel	17.6	29.3	16.3	7.9
LNG	0.0	1.0	0.0	5.0
Natural Gas	626.8	466.0	640.1	800.0
Nuclear	0.0	0.0	139.1	200.0
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	5.0	1.7	3.3	3.7
Naphtha	0.0	0.0	0.0	0.0
Geothermal	268.0	305.3	228.9	630.8
Hydro	148.3	210.7	185.1	309.4
Run-of-river	66.2	68.3	71.8	75.5
Solar	24.6	30.0	167.1	230.7
Wind	74.1	100.2	103.6	103.6
Total	2279.8	2207.7	2648.3	3546.6

Table 5.19 and Figure 5.13 show individual and total supply consumption and consumption shares in the supply mix for each type of supply. Even though this scenario includes YEKDEM, there is no increase in wind supply consumption. It decreases for the milestone years 2020, 2025, and 2030 compared to the SCENREF scenario. Other supply sources have similar consumption amounts and shares throughout the model horizon as the SCENREF scenario.

Table 5.20 shows the total and individual electricity production amounts in PJ for each milestone year. Figure 5.13 shows the shares in the supply mix for each supply type. There is a decrease, which is compensated mainly by wind power plants, from the electricity produced by imported coal, geothermal and solar power plants in 2020 compared to the SCENREF scenario. However, the electricity produced by wind power plants decreases by 7% in 2025 and 10% in 2030, according to the SCENREF scenario. Also, the electricity production by hydro supply suffers a significant decrease of 20% in 2020 and 30% in 2025. The total electricity production share of renewable energy sources is the same as SCENREF scenario.

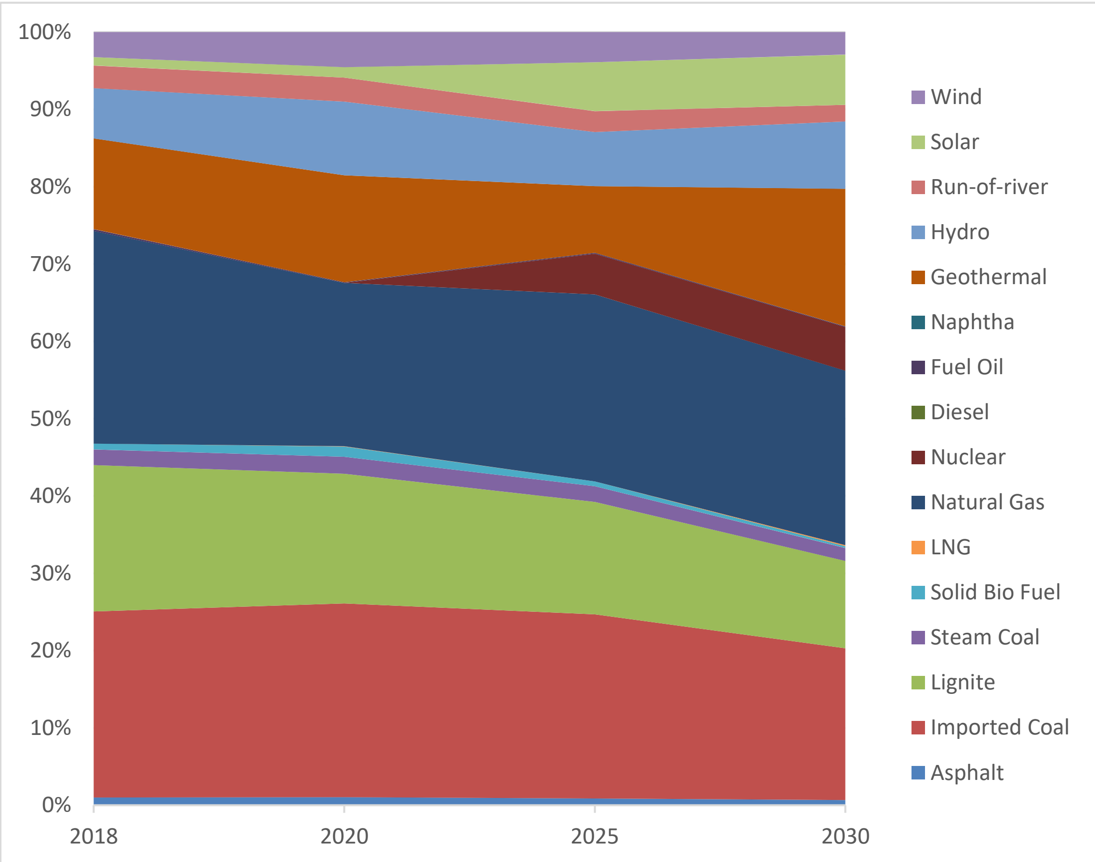

Figure 5.13 Supply consumption ratios for wind regional with government incentive

scenario

Table 5.20 Electricity production amounts in PJ for wind regional with government incentive scenario

	2018	2020	2025	2030
Asphalt	8.0	8.1	8.2	8.3
Imported Coal	224.7	213.7	253.9	278.5
Lignite	161.4	138.3	141.1	150.6
Steam Coal	12.3	13.6	18.9	20.9
Solid Bio Fuel	8.3	13.3	6.7	2.8
LNG	0.0	0.0	0.0	0.0
Natural Gas	332.2	247.5	339.2	426.7
Nuclear	0.0	0.0	62.6	90.0
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	2.8	1.1	1.4	1.4
Naphtha	0.0	0.1	0.0	0.0
Geothermal	26.8	30.5	22.9	63.1
Hydro	148.3	210.7	185.1	309.4
Run-of-river	66.2	68.3	71.8	75.5
Solar	24.6	30.0	167.1	230.7
Wind	74.1	100.2	103.6	103.6
Total	1089.8	1075.6	1382.6	1761.3

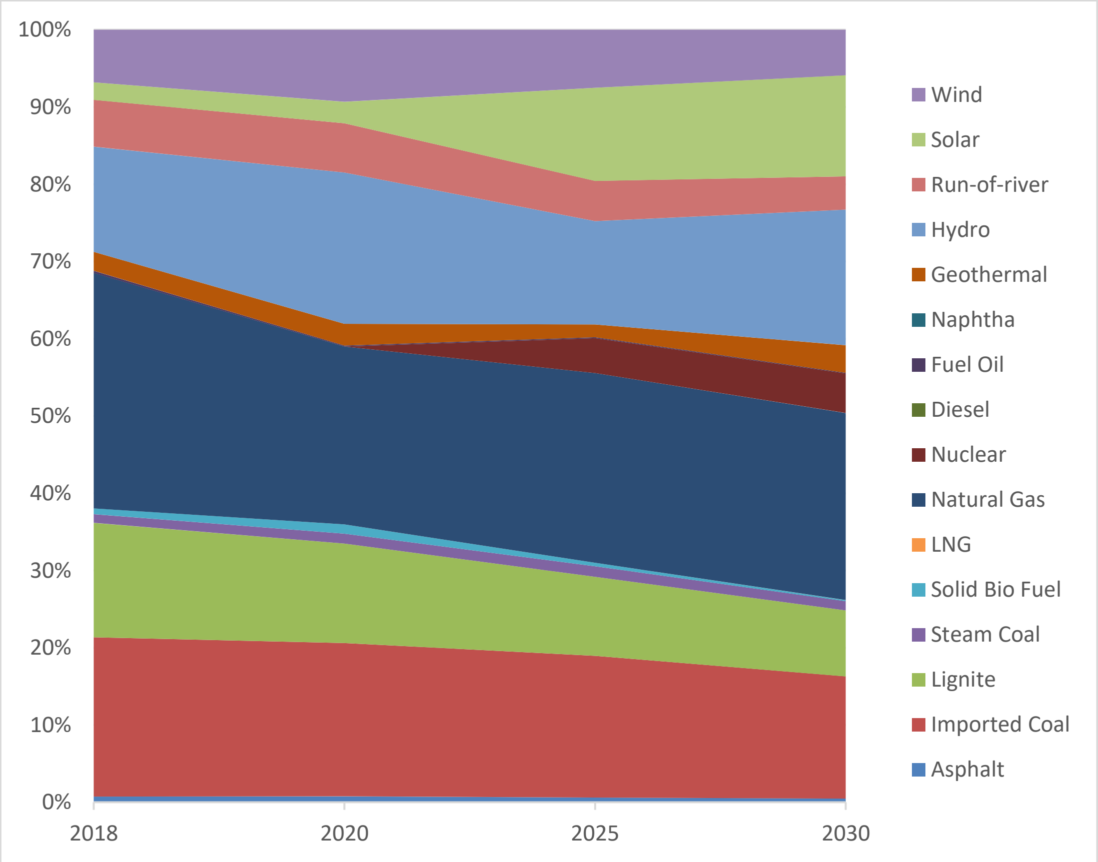

Figure 5.14 Electricity production ratios for wind regional with government incentive scenario

Table 5.21 Technology capacities in GW for wind regional with government incentive scenario

	2018	**2020**	**2025**	**2030**
Asphalt	0.4	0.4	0.4	0.4
Imported Coal	9.2	8.3	14.6	12.4
Lignite	9.5	10.0	9.5	8.1
Steam Coal	0.4	0.5	9.0	8.8
Solid Bio Fuel	0.7	0.8	0.6	0.2
LNG	0.0	0.0	0.0	0.0
Natural Gas	25.9	26.5	15.6	27.4
Nuclear	0.0	0.0	2.4	3.6
Diesel	0.0	0.0	0.0	0.0
Fuel Oil	0.6	0.5	1.2	1.0
Naphtha	0.0	0.0	0.0	0.0
Geothermal	1.5	1.6	0.9	2.6
Hydro	20.5	23.4	20.8	34.8
Run-of-river	7.7	7.7	7.5	7.9
Solar	5.1	5.1	14.6	24.3
Wind	7.0	7.8	8.5	8.5
Total	88.4	92.6	105.7	140.2

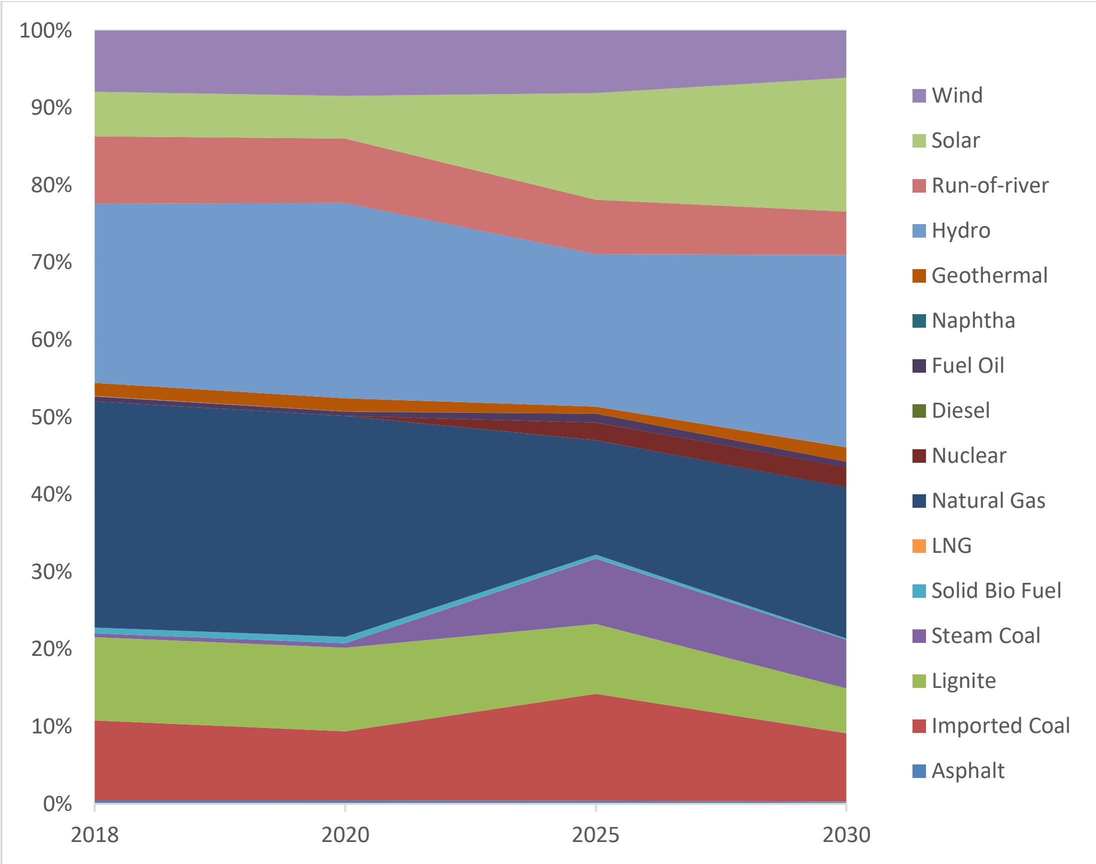

Figure 5.15 Technology capacity ratios for wind regional with government incentive scenario

Table 5.21 and Figure 5.15 show the details of technology capacities both in GW and percentage shares. Compared to the SCENREF scenario, there are some increases in the capacity of wind power plants, around 2 GW in 2025 and 2030. The highest capacities for wind power plants are installed in Balıkesir, Çanakkale, and İzmir provinces. The total capacity of renewable energy power plants increases by 3.4 GW compared to SCENREF scenario.

Table 5.22 shows the average monthly and annual electricity prices for SCENWNDYEK scenario. The average yearly electricity price increases to 63.8 USD cents per MWh in 2020, which is lower by 14% compared to the SCENREF scenario. In 2025 the electricity prices for each month significantly decrease. The average yearly electricity price decreases until the end of the model horizon and becomes 43.7 cents per MWh in 2030. March, April, and June have the lowest electricity prices among all months in 2025 and 2030. December holds the highest average electricity price throughout all months in each milestone year.

Table 5.22 Average monthly and yearly electricity prices of wind regional with government incentive scenario ($/MWh)

SCENWNDYEK	2018	2020	2025	2030
January	20.7	60.9	23.3	43.2
February	20.3	75.2	22.8	39.4
March	17.6	29.5	18.7	33.2
April	18.6	31.5	18.6	31.0
May	20.5	70.8	26.4	40.3
June	20.1	57.2	22.2	31.4
July	19.5	60.8	26.0	37.3
August	16.9	44.7	26.8	36.7
September	19.2	58.2	26.0	36.7
October	20.5	85.6	28.8	39.4
November	19.7	90.9	31.0	42.3
December	20.8	100.4	314.4	112.9
Average	19.5	63.8	48.7	43.7

While the capacity of wind power plants increases slightly, the electricity produced by them decreases in SCENWNDYEK scenario compared to SCENREF scenario. The carbon dioxide emissions decrease by 3% in 2025, and no significant change in the total system cost includes YEKDEM costs compared to the SCENREF scenario.

5.4 Discussion of Scenarios

Table 5.23 shows the electricity production mix of all scenarios. Natural gas is the dominant energy source for electricity production in each milestone year across all scenarios. The share of electricity production from natural gas decreases by 2.6% within SCENSOL scenario and by 3.2% within SCENSOLYEK scenario in 2025. There is no other significant increase or decrease in the shares of natural gas. Hydro has similar shares in the electricity production mix within SCENREF, SCENWND, and SCENWNDYEK scenarios. In years 2030 of SCENSOL and SCENSOLYEK scenarios, the share of hydro decreases by 5% compared to the SCENREF scenario. The solar shares increase remarkably in SCENSOL and SCENSOLYEK scenarios. Especially in SCENSOLYEK scenario, it increases by 7% compared to the SCENREF scenario and becomes 20% in 2030. There are slight decreases in the wind shares under

0.6% in SCENSOLYEK, SCENWND, and SCENWNDYEK scenarios. The wind share increases only in 2020 within SCENWNDYEK scenario by 1.1% compared to SCENREF.

Table 5.24 shows the total system costs, including YEKDEM costs, in 2018 MUSD for SCENSOLYEK and SCENWNDYEK scenarios. The highest increases in total cost, around 0.07% compared to SCENREF scenario, occur in 2025 within SCENWND and SCENWNDYEK scenarios. The total cost decreases in 2030 for SCENSOL and SCENSOLYEK scenarios. The most significant decrease occurs in SCENSOL scenario by 0.08% compared to SCENREF scenario.

The carbon dioxide emissions in metric tons for every scenario can be seen in Table 5.25. The most significant decrease in carbon dioxide emissions is seen by 8% in 2025 within SCENSOLYEK scenario compared to SCENREF scenario.

Examples of the hourly marginal electricity prices on Wednesdays of April, August, and December for 09:00 and 19:00 can be seen in Tables 5.26 and 5.27. The highest hourly marginal electricity prices are seen in the evenings (19:00). The prices are significantly low in the mornings (09:00). In 2025 and 2030, SCENSOLYEK has the smallest marginal electricity prices for hours 09:00 and 19:00 in April, August, and December. In the morning, it has some negative marginal prices, resulting from electricity generation from solar power plants. In the evening, there appears to be no excess electricity supply, and in 2025, the marginal price for SCENSOLYEK is still the lowest among other scenarios. However, in 2030, the SCENCOLYEK scenario has the highest marginal electricity prices, especially in the evening, among all scenarios.

Table 5.23 Shares of electricity production by primary energy resources for each milestone year across all scenarios (%)

SCENREF	2018	2020	2025	2030
Asphalt	0.7%	0.8%	0.6%	0.5%
Imported Coal	20.6%	20.1%	18.3%	15.8%
Lignite	14.8%	12.9%	10.2%	8.5%
Steam Coal	1.1%	1.3%	1.4%	1.2%
Solid Bio Fuel	0.8%	1.2%	0.5%	0.2%
LNG	0.0%	0.0%	0.0%	0.0%
Natural Gas	30.6%	23.0%	24.5%	24.2%
Nuclear	0.0%	0.0%	4.5%	5.1%
Diesel	0.0%	0.0%	0.0%	0.0%
Fuel Oil	0.3%	0.1%	0.1%	0.1%
Naphtha	0.0%	0.0%	0.0%	0.0%
Geothermal	2.5%	3.6%	2.4%	3.6%
Hydro	13.6%	19.6%	13.4%	17.0%
Run-of-river	6.1%	6.4%	5.2%	4.3%
Solar	2.2%	2.8%	11.1%	13.0%
Wind	6.8%	8.3%	8.0%	6.5%

Gross Production (PJ)	1090.5	1074.1	1385.2	1761.5

SCENSOL	2018	2020	2025	2030
Asphalt	0.7%	0.8%	0.6%	0.5%
Imported Coal	20.6%	20.0%	18.4%	15.9%
Lignite	14.8%	12.9%	10.3%	8.7%
Steam Coal	1.1%	1.1%	1.4%	1.2%
Solid Bio Fuel	0.8%	1.2%	0.5%	0.2%
LNG	0.0%	0.0%	0.0%	0.0%
Natural Gas	30.5%	23.1%	21.9%	24.4%
Nuclear	0.0%	0.0%	4.5%	5.2%
Diesel	0.0%	0.0%	0.0%	0.0%
Fuel Oil	0.3%	0.1%	0.0%	0.1%
Naphtha	0.0%	0.0%	0.0%	0.0%
Geothermal	2.5%	2.8%	1.5%	3.6%
Hydro	13.6%	19.7%	13.4%	12.0%
Run-of-river	6.1%	6.4%	5.2%	4.3%
Solar	2.3%	3.6%	14.2%	17.5%
Wind	6.8%	8.3%	8.1%	6.6%
Gross Production (PJ)	1089.8	1071.0	1377.2	1747.4

SCENSOLYEK	2018	2020	2025	2030
Asphalt	0.7%	0.8%	0.6%	0.5%
Imported Coal	20.6%	19.6%	18.0%	15.4%
Lignite	14.8%	12.9%	10.0%	8.5%
Steam Coal	1.1%	1.1%	1.3%	1.2%
Solid Bio Fuel	0.8%	1.2%	0.5%	0.2%
LNG	0.0%	0.0%	0.0%	0.0%
Natural Gas	30.5%	22.8%	21.3%	23.7%
Nuclear	0.0%	0.0%	4.3%	5.0%
Diesel	0.0%	0.0%	0.0%	0.0%
Fuel Oil	0.3%	0.1%	0.0%	0.1%
Naphtha	0.0%	0.0%	0.0%	0.0%
Geothermal	2.5%	2.7%	1.4%	3.5%
Hydro	13.6%	19.6%	13.0%	11.5%
Run-of-river	6.1%	6.4%	3.4%	4.2%
Solar	2.3%	4.6%	18.3%	20.0%
Wind	6.8%	8.2%	7.9%	6.4%
Gross Production (PJ)	1089.8	1073.5	1412.9	1803.7

SCENWND	2018	2020	2025	2030
Asphalt	0.7%	0.8%	0.6%	0.5%
Imported Coal	20.6%	20.1%	18.3%	15.8%
Lignite	14.8%	12.9%	10.2%	8.5%
Steam Coal	1.1%	1.3%	1.4%	1.2%
Solid Bio Fuel	0.8%	1.2%	0.5%	0.2%
LNG	0.0%	0.0%	0.0%	0.0%
Natural Gas	30.6%	23.0%	24.1%	24.2%
Nuclear	0.0%	0.0%	4.5%	5.1%
Diesel	0.0%	0.0%	0.0%	0.0%
Fuel Oil	0.3%	0.1%	0.1%	0.1%
Naphtha	0.0%	0.0%	0.0%	0.0%
Geothermal	2.5%	3.6%	2.3%	3.6%
Hydro	13.6%	19.6%	13.4%	17.7%
Run-of-river	6.1%	6.4%	5.2%	4.3%
Solar	2.2%	2.8%	11.9%	13.0%
Wind	6.8%	8.3%	7.5%	5.9%
Gross Production (PJ)	1090.5	1074.1	1383.1	1761.5

SCENWNDYEK	2018	2020	2025	2030
Asphalt	0.7%	0.8%	0.6%	0.5%
Imported Coal	20.6%	19.9%	18.4%	15.8%
Lignite	14.8%	12.9%	10.2%	8.6%
Steam Coal	1.1%	1.3%	1.4%	1.2%
Solid Bio Fuel	0.8%	1.2%	0.5%	0.2%
LNG	0.0%	0.0%	0.0%	0.0%
Natural Gas	30.5%	23.0%	24.5%	24.2%
Nuclear	0.0%	0.0%	4.5%	5.1%
Diesel	0.0%	0.0%	0.0%	0.0%
Fuel Oil	0.3%	0.1%	0.1%	0.1%
Naphtha	0.0%	0.0%	0.0%	0.0%
Geothermal	2.5%	2.8%	1.7%	3.6%
Hydro	13.6%	19.6%	13.4%	17.6%
Run-of-river	6.1%	6.4%	5.2%	4.3%
Solar	2.3%	2.8%	12.1%	13.1%
Wind	6.8%	9.3%	7.5%	5.9%
Gross Production (PJ)	1089.8	1075.6	1382.6	1761.3

In conclusion, the government incentive, YEKDEM, provides an increase in the electricity production share of solar within the energy mix and does not significantly affect the share of wind. This increase in solar brings a decrease in the annual representative electricity prices, carbon dioxide emissions, and system costs.

Table 5.24 Total system and YEKDEM costs across all scenarios **(**2018 MUSD)

	2018	2020	2025	2030
SCENREF	2,620,324	2,609,679	2,617,741	2,628,419
SCENSOL	2,619,849	2,610,660	2,618,922	2,626,252
SCENSOLYEK	2,619,638	2,609,692	2,617,838	2,627,309
SCENWND	2,620,324	2,610,319	2,619,556	2,628,939
SCENWNDYEK	2,619,578	2,610,248	2,619,672	2,629,096

Table 5.25 Total carbon dioxide emissions across all scenarios (ktoe)

	2018	2020	2025	2030
SCENREF	101,823	108,114	256,983	352,906
SCENSOL	101,916	105,795	252,111	352,811
SCENSOLYEK	101,916	104,160	249,243	352,811
SCENWND	101,806	108,122	255,757	352,916
SCENWNDYEK	101,916	106,736	253,998	352,915

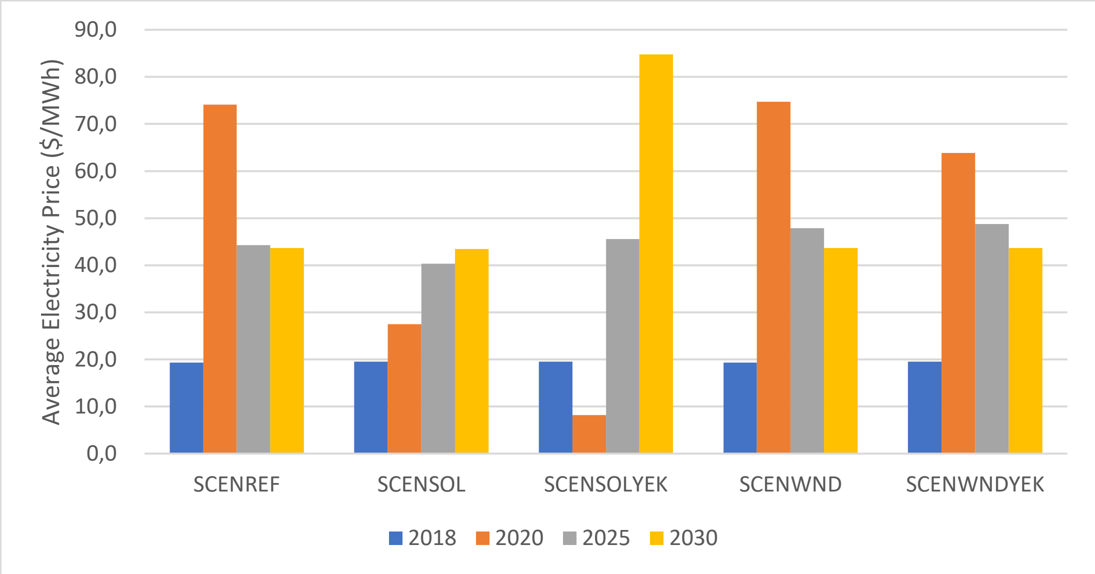

Figure 5.16 Annual representative electricity prices for each milestone year across all scenarios ($/MWh)

Table 5.26 Hourly marginal electricity prices on Wednesdays of April, August, and December for 09:00 and 19:00 in 2025 ($/MWh)

	09:00			19:00		
	APRIL	AUGUST	DECEMBER	APRIL	AUGUST	DECEMBER
SCENREF	17.4	17.4	36.6	36.6	36.6	36.6
SCENSOL	3.7	21.9	21.9	35.7	35.7	35.7
SCENSOLYEK	-15.3	-15.3	3.7	27.7	27.7	27.7
SCENWND	21.1	21.1	40.7	44.4	44.4	44.4
SCENWNDYEK	21.1	21.1	41.6	45.3	45.3	45.3

Table 5.27 Hourly marginal electricity prices on Wednesdays of April, August, and December for 09:00 and 19:00 in 2030 ($/MWh)

	09:00			19:00		
	APRIL	AUGUST	DECEMBER	APRIL	AUGUST	DECEMBER
SCENREF	2.7	2.7	47.9	47.9	47.9	47.9
SCENSOL	1.2	1.2	1.2	60.8	60.8	60.8
SCENSOLYEK	-15.8	-15.8	-15.8	69.6	69.6	69.6
SCENWND	2.7	2.7	48.0	48.0	48.0	48.0
SCENWNDYEK	2.7	2.7	47.8	47.8	47.8	47.8

CHAPTER 6

6. CONCLUSION

In this study, the Turkish electricity sector is examined within TIMES framework. An electricity sector model which can evaluate the hourly electricity production and consumption between 2018 and 2030 is used. Five different scenarios are applied, and the results are compared. These scenarios include a reference scenario, regional wind, and regional solar scenarios, and also scenarios that include government incentives for wind and solar. In all scenarios, only electricity production and consumption are included. The model does not include any other sector. All processes and commodities are related to the electricity sector.

The results show that the government incentives for solar power plants help to reduce carbon dioxide emissions without increasing the total system cost. It brings the renewable energy share in Turkish electricity production to 46%. However, the electricity price for end-user fluctuates significantly. The system chooses some provinces with the highest availability to install the most significant capacity. It uses all provinces for regional wind and solar scenarios, even with small capacity installments.

The capacity projections of solar power plants in future years are always higher in the solar regional scenarios than in the other scenarios. In scenarios without regional solar representation, future solar capacity factors are calculated by the previous electricity production data. In these scenarios, the electricity production share of solar power plants reaches around 13% in 2030. While in solar regional scenarios, the capacity factors for future years are calculated by SARAH's current solar data, and the electricity production share of solar power plants increases to 20% in solar regional with government incentive scenario. Around 40% of solar power plant capacity is installed as rooftop technologies across all scenarios.

In the wind regional scenarios, only onshore capacity availabilities and factors for wind power plants are implemented. Therefore, the low investment in wind power plants compared to solar power plants can be the result of this choice in implementation. Further studies with offshore wind power plant implementation may enlighten this behavior of the model.

This study can be improved by including the other sectors of the Turkish energy system. Including more than one sector requires an enormous computational capacity on the hourly time-slice level. The same computational capacity limits prevent the integration of solar and wind regional technologies in the same scenario. However, the electricity demand can be defined as regional in future works. Also, some storage technologies for renewable power plants can be integrated into the model. Moreover, a detailed analysis of hourly electricity prices can be done.

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