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RESEARCH ARTICLE

Analysis of Long-Term Variable Renewable Energy Heavy Capacity Plans Including Electric Vehicle and Hydrogen Scenarios: Methodology and Illustrative Case Study for Turkey

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ABSTRACT Following COP26, many countries are embarking on decarbonization strategies for the power sector that may include inter alia storage, hydrogen, and carbon capture (and storage). There is also significant increase in load that may come in the form of electric vehicles (EV) charging and hydrogen requirement for decarbonization of other sectors. While there is a growing literature around long-term decarbonization strategies, there is still ample room for a practical methodology to rigorously test capacity plans to include a range of options inter alia re-optimization of the mix of renewable technologies, better coordination of the (EV) load from a system perspective, or augmenting the plan with battery energy storage (BESS) and hydrogen. This paper presents our research on EV load and green hydrogen modeling including how they can be integrated into long-term electricity models. We also present a methodology that allows planners to undertake a rigorous assessment that can be readily implemented using the World Bank Electricity Planning Model (EPM). The application of the model is illustrated through a case study for Turkey (Türkiye) for 2050. The case study shows how an incumbent policy-driven capacity plan for 2050 that included 33% contribution from variable renewable energy (VRE) may be prone to unserved energy risk during winter months due to seasonal variability of VRE. The analysis goes on to demonstrate how the plan can be reinforced with additional peaking gas turbines, re-optimization of wind and solar, BESS and hydrogen. Coordinated charging of EVs is also shown to bring significant relief to investment requirements.

INDEX TERMS Electric vehicles, power system optimization, least-cost planning, variable renewable energy, decarbonization, hydrogen.

I. INTRODUCTION

With its fast-growing energy demand and high dependence on imported oil and natural gas, Turkey's (Türkiye) most recent energy strategy focuses on strengthening energy supply security by increasing the share of domestic energy resource use in its energy mix. Domestic resources in Turkey primarily include coal, solar, wind and to a lesser extent geothermal. In addition to these sources, Turkey has plans to introduce nuclear into its energy mix in the coming years [1]. The 2019-2023 Strategic Plan of Ministry of Energy and Natural Resources (MENR) sets a short-term goal of increasing the share of renewables in electricity generation up to 38.8 percent by 2023. Turkey has already achieved this goal by reaching 42 percent of renewables share in generation in 2020 [2]. In terms of installed capacity, the share of renewables is 51%, while the rest consists of coal and natural gas.

While the strategic targets point to the further expansion of renewable energy, Turkey has already taken significant steps towards decarbonization. Preceding the COP26 meeting, Turkey ratified the Paris Agreement and committed to net zero by 2053. Turkey's National Climate Change Action Plan (2011-2023) as well as its INDC targets fall short to address the needs of net zero decarbonization and are expected to

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be updated in light of the recent commitments. A newly established Climate Change Council under the Ministry of Environment, Urbanization and Climate Change (MoEUCC) is expected to oversee the development of a net zero roadmap and strategy. In its June 2022 meeting, the Council announced 217 climate actions in various sectors and topics. These action items will help formulate the National Climate Policy that is currently under preparation (Ministry of Environment, Urbanization and Climate Change, n.d.). Developing a long-term energy plan in line with the 2053 net zero goal ahead of COP27 is the top energy sector priority of the Council. In addition, increasing the share of VRE as well as system flexibility options are listed among the main decisions to be pursued in the energy sector. The council also decided that a Hydrogen Strategy and Roadmap that prioritizes green hydrogen should be prepared. Consideration of carbon capture and storage technologies, introducing nuclear into the energy mix and investing in demand side management and energy efficiency are among other relevant action items. In terms of decarbonization of the transport sector, the Council emphasizes the need of electrification of the sector.

A heavy emphasis on decarbonization as well as energy supply security implies that the Turkey's electricity sector will be required to further scale-up the contribution of VRE and storage technologies for its long-term energy needs. This is reflected in MENR's 2050 plan to include as much as 33% of electricity coming from VRE resources.

II. LITERATURE REVIEW

A. OVERVIEW OF POWER SECTOR MODELS FOR DECARBONIZATION ANALYSIS

Optimization models have long been used for power system planning e.g., studies by NREL USA [3], [4], [5], [6], [7]. Currently, in the context of the ongoing energy transition, power sector models are increasingly important for the development of long-term decarbonization pathways extending over several decades [8].

Analysis focusing on integration of VRE in the power sector is often performed with the use of least-cost optimization models. The choice and application of a model is based on user expert decisions to balance among robustness, computational effort and required level of accuracy. These in turn require judicious selection of solver, the level of temporal disaggregation of the problem, access to good quality historical data. There are other criteria such as a model's ability to account for system, regulation and policy constraints, representation of unit commitment constraints, ability to account for the geospatial effects of VRE and adequate representation of the grid [9], [10], [11], [12], [13], [14], [15].

Analyses related to grid integration of VRE is usually conducted with the use of one or more of the following types of power sector models:[1]

a) Least-cost capacity expansion models are used to assess the least cost technology mix to provide future demand subject to technical, system, policy, and environmental constraints. They usually make use of low-level temporal detail on representation of electricity demand and VRE resource. As a result, least-cost capacity expansion models have poor capability to analyze in detail intra-hour and even intra-day effects, including impacts of variability on system operations and simulation of medium and long-term storage operation (see table 1).
b) Production cost models are used to simulate system operation in detail subject to unit and system constraints. They are capable of simulating unit dispatch and allocation of reserves using finer time steps and are used to assess system flexibility, sizing of energy storage and optimal charging of EVs. Capacity mix is a fixed input to these models.

Several international organizations, research centres, academic institutions and privately owned firms involved in energy and climate related research have developed a number power sector models [17], [18], [19], [20], [21], [22], [23], [24], [25], [26], [27]. As more tools become available there have been efforts to categorize such tools based on characteristics, capabilities, spatial and temporal granularity and scope [28], [29]. There are ongoing efforts to expand their capabilities to consider emerging topics such as energy storage, electric vehicles and hydrogen production [30], [31], [32].

B. IMPACT OF EVs ON THE LOAD

Decarbonization of the energy sector will largely be based on large-scale adoption of renewable energy sources, especially VRE, and electrification of sectors and subsectors that are otherwise difficult to decarbonize. More specifically, electrification of the transport sector, which currently accounts for about 11% of global energy related emissions, could reach electrification levels of 45% by 2050. The fleet of two wheelers, light- and medium- duty vehicles will need to be electrified at very high levels. Green hydrogen is likely to drive decarbonization of aviation, heavy duty vehicles and sea transport [33], [34], [35]. Large scale adoption of EVs will impact the growth rate and the profile of the load. Studying the projected changes on magnitude and shape of EV load is necessary to estimate the required technology mix to reach specific climate goals.[2]

EVs are expected to cause a moderate increase on global total electricity demand by 2050.[3] However, if charging remains uncoordinated the capacity increase on the daily

[1] It should be noted that there are also grid analysis models, however not based on optimization methods, which are used to support T&D expansion and system stability analysis [16].

[2] Many studies focus on the impact of EVs on the distribution network aiming to estimate the required network upgrades. While this is a very real short- to medium- term concern, this study focuses on EV integration impacts from a higher altitude focusing on the shape of the aggregated EV load and the technology mix required to supply the updated demand.

[3] At around 10 to 15% for most countries, even though the increase will be more substantial for others.

TABLE 1. **Comparison of least-cost capacity expansion and production cost models.**

	Least-cost capacity expansion (LCP)	Dispatch simulations
Typical study goals	Decarbonization pathways (capacity expansion plans, cost of transition, electrification of other sectors, CO2 emissions), development of regulation and policy	Assessment of system flexibility, system benefits from operational improvements (geographic dispersion of VRE, regional interconnections, VRE forecasts), benefits of energy storage (electricity storage and hydrogen), optimal EV charging, benefits of flexible load
Optimization horizon	Usually, 10 years to a few decades	Up to 1 year
Optimization goal	Minimize total system investments and operational costs	Minimize operational costs
Electricity demand representation	Choice of typical days (24-hour representation)	Full chronological representation using hourly step or even finer
Variable renewable energy representation	Choice of typical days (24-hour representation)	Full chronological representation using hourly step or even finer
T&D representation	High level representation of real power flows on the transmission grid. Not capable of representing investments and energy exchange at the distribution grid	Mostly high-level representation of real power flows on transmission grid. Some models have capabilities to represent AC power flows which can be used to provide high level insights.
Typical outputs	Capacity expansion plan (installed capacity and investments), approximation of the energy mix, operational costs, and CO2 emissions	Detailed dispatch and allocation of reserves of production units and energy storage, operational costs, and CO2 emissions

load profile could be substantial and difficult to manage from a system operation perspective [36], [37], [38], [39], [40], [41]. Understanding when, where and how fast drivers charge allows utilities to adjust their load projections for EV charging.

In general, the EV load profile depends on the type of vehicle (light duty vehicles, medium and heavy-duty vehicles (MHDVs), buses, two and three wheelers), usage of EVs (private commute, commercial use, commute of public, transfer of goods), charging behaviour (temporal preference on plugging-in to charge), the vehicle mileage, the size of the battery, and the speed of charging. The following paragraphs in this section intent to discuss the findings of various research related to the charging behaviour of EV owners. This is because the EV load analysis presented later in this paper is largely dependent on assumptions related to uncoordinated versus coordinated charging behaviour. Charging behaviours below are categorized based on different types of EVs and related use.

Due to favourable techno-economics, adoption of battery technology in passenger cars is currently driving the technological shift in the transport sector. There are increasing number of studies focusing on EV load profiles based on historical charging data. It is common in such studies to estimate EV load based on location (residential, work, public) and speed of charging (slow, fast, rapid). As an example, extensive data covering more than 30,000 residential charging events and over 3,200 public charge points across the UK, show significant differences in residential charging profiles between commuters and non-commuters. Commuters have a high propensity to plug in their EVs on weekdays between 5pm and 9pm when they arrive from work, whereas non-commuters spread their charging time more evenly throughout the afternoon (see fig. 33) [42].

At most workplaces, charging events begin in the mid-morning around 9am, coinciding with commuters' arrival to work (see fig. 34). On weekdays, large public charging begins in the morning at around 9am, while in weekends it occurs throughout the day (see fig. 35). Fig. 33 to 35 in the Appendix refer to the probability of a charging event starting at time t of the day, also called plug-in probability profile (PPP). The final load profile depends largely on the speed of charge. Slow charging extends over many hours while rapid charging creates short but quite large peaks. Fig. 36 shows the combined EV load from residential, work, and public charging in Great Britain over a typical week. The EV charging profile is characterized by a sharp peak during early evening in weekdays and a less prominent one in the morning. In a typical weekend, charging extends throughout the day and the peak occurs late afternoon/early evening [43]. Similar charging behaviour for electric cars has been observed in other countries as well [36], [40], [44], [45], [46]

As more real-world data become available, the focus in research is gradually expanding to other types of EVs including MHDVs which have a significant CO_2 footprint even though they exist in smaller numbers compared to cars. As an example, the CO_2 share (over total road transport related CO_2) of MHDVs could be an order of magnitude larger compared to their vehicle number share (over total number of vehicles) [47]. MHDVs are typically part of commercial fleets which present good potential for electrification. As an increasing number of fleet owners around the world are committing to electrify part or the whole of their fleets, there is increased interest on the impacts of the aggregate load especially in urban areas [48]. As an example a single bus depot may require 2-10MWs of charging capacity [49], [50]. It is reasonable to assume then that the future aggregated profile of MHDV's can be quite significant.

The uncoordinated load profile of vans, trucks and buses largely depends on the service hours; usually charging begins at the time when a vehicle returns to the depot/charging area and the charging window closes by the time a vehicle needs to get out to service again [51], [52]. Reference [52] has been studying the charging loads for school buses and freight trucks day in a specific area of the National Grid's service territory. School buses are most likely to be parked and charging post 3pm while freight trucks post 9pm (see fig. 37 to 39 in Appendix). Reference [53] focuses on public buses and compares the charging schedule for two battery electric buses (BEBs) in Chicago Transit Authority which constitutes for 3 to 5 hours overnight charging at 100 kW and another 3 to 5 hours of midday charging.

Electrification of two-wheelers (2Ws) and three-wheelers (3Ws) is rapidly expanding especially in the Asian markets. Around 80% of 2Ws in China are electrified while half of all rickshaws in India are currently electric. Furthermore, the Indian government has set a target for 80% of 3Ws by 2026. 2Ws have wide both commercial and personal use. Commercial use of 2Ws is related to e-commerce, food and grocery delivery and passenger mobility. 3Ws are mostly used for passenger mobility [54].

The charging profile of two and three wheelers depends on commercial vs private type of use and battery charging business model (battery swap, depot, street charging), Charging a single 2W or 3W battery has a minimal impact of the grid. However in specific countries the aggregate impact from electrification of 2Ws could be significant and is comparable to, or larger than, other types of vehicles due to the disproportionately high number of electric 2Ws on the streets [55]. Unfortunately, there is no literature available focusing on the aggregate load from 2W and 3W.

Uncoordinated charging could increase considerably the peak demand, thus increasing the cost of supplying electricity in the form of capital expenditure (CAPEX) for additional peaking capacity. Coordinated charging can mitigate the impacts of electrification of the transport sector and bring significant economic and operational benefits to the power system at a low cost. Coordinated charging can be implemented through several incentives to shift the charging load away from the peak. A modeling analysis conducted by the World Bank for Maldives using the EPM model comprehensively demonstrated that coordinated charging can lead to substantial reduction in peaking generation capacity [56].

III. STUDY GOALS

The motivating idea for this work stems from the fact that there is a serious need to develop capacity plans that fully consider these details on both supply and demand side including investment requirements to support new capacity as well as the system reliability issues that would be impacted by higher demand and inclusion of substantial variable renewable energy resources and variability of demand (Due to EV/hydrogen production). Existing electricity capacity plans are typically being updated driven by long-term decarbonization policies to add substantial solar and wind generation in particular. Such a capacity plan would however need to be tested carefully to ensure that (i) the plan is adequate in terms of firm capacity, (ii) there is sufficient energy availability taking into account seasonal and inter-annual variability of solar, wind and hydro resources; and (iii) the underlying dispatch renders the system secure in terms of sufficient frequency control reserve and observes technical constraints and system operational rules. Additional requirements for clean energy will also be driven by the need to meet demand from electric vehicles and green hydrogen, albeit the latter can also be a useful aid to manage variability of solar/wind and as a long-term storage/generation resource. The principal innovation of our work is that a conventional system planning model has been augmented with decisions that consider investments on electrolyzers for green hydrogen production fully integrated in the generation investment and dispatch optimization.

The above proposed methodologies and model upgrades have been applied in a real-world case using data from the Turkish power sector. Firstly, this work evaluates the existing Turkish capacity plan for 2050 from an energy and capacity adequacy perspective. Existing capacity expansion plans are assessed through a detailed dispatch analysis using an hourly timestep. Secondly, this study aims to complement the capacity plan with alternative technologies through least-cost planning analysis. More specifically, World Bank's EPM model is supplemented with the required mathematical formulation to consider electrolyzers as an additional demand-side investment for production of green hydrogen. Costs and benefits of green hydrogen for decarbonizing the power sector is a key element of this work. Thirdly, we provide a methodology to estimate the hourly EV load profile based on official annual EV load projections and data from the Turkish transport sector. This is because hourly load is one of key inputs for LCP and dispatch models like EPM. Both production of green hydrogen and electrification of transport (and other sectors) can potentially create significant changes to the combined electricity demand profile such as significant change on the magnitude and timing of both the peak demand and the gap between peak and valley. Finally, this work further considers the impacts of coordinated EV charging on system operations and costs. Coordinated EV load profiles are estimated on the basis of providing incentives to shift charging towards low system marginal prices. In all cases, costs and benefits of different actions are assessed through comparative analysis of study scenarios. Real-world system constraints and risks related to VRE uncertainty have been taken into account throughout the analysis.

IV. METHODOLOGY

The methodology deployed for the analysis has two distinct components, namely, a check on the robustness of an existing plan; and enhancing the plan if the incumbent plan leaves the system vulnerable to low system security or worse load shed events. It is structured this way as governments often have an in-situ master plan that is often prepared using conventional planning tools that may or may not fully consider the impacts of large-scale VRE and/or load impact of new technologies like EV or hydrogen. As the case study in a subsequent section demonstrates the draft electricity plan for Turkey needed checks on seasonal and interannual variability of solar and wind that may leave the system exposed to significant risk of loss of load. The methodology then deals with fixing the plan. This is where an innovative approach is needed to fully integrate the impacts of renewable and EV load variability as well endogenous optimization of hydrogen production which can be used to both augment power production during periods of low RE availability as well as meet external (non-power) demand for hydrogen. The methodological improvements around EV and hydrogen have been implemented in an existing planning model, namely, the World Bank Electricity Planning Model (EPM). The next section discusses the EPM model and specific steps followed as part of the methodology.

A. GENERAL METHODOLOGICAL APPROACH WITH EPM

The analysis is based on the World Bank EPM model. EPM is a least-cost planning tool written in General Algebraic Modeling System (GAMS) language which can be used for both long-term capacity expansion analysis and production cost modeling. The objective of EPM is to minimize total system costs subject to several system, unit, and policy constraints. Detailed description of all equations comprising the power system optimization problem in EPM can be found in reference [57]. The methodological approach can be broken down into two thematic sections:

Thematic section a): Methodology to assess and bridge system adequacy gaps in the incumbent plan.

1) Use existing capacity plans for a Baseline scenario provided by MENR to assess system adequacy. The Baseline scenario is representative of moderate climate action aiming for a minimum of 33% VRE by 2050. Initially EPM is run in production cost mode to simulate system performance for years 2049 and 2050. The projected demand has been estimated considering uncoordinated EV load charging. EPM reports key indicators like loss of load, VRE curtailment, shortage on firm capacity reserves to assess the magnitude, and temporal incidence of such events.
2) Optimize system investments and operation to bridge any adequacy gaps. EPM is run simultaneously on capacity expansion and production cost mode. The capacity expansion is performed for two years (2049 and 2050) provided the existing capacity plan for the above years is given (based on information by MENR) optimizing for additional investments to ensure energy and capacity constraints are satisfied.[4] Only supply-side technologies (mainly CCGT, OCGT, PV and wind) and electricity storage (BESS and PHP) are considered for system expansion.

Thematic section b): Development of decarbonization pathways for Turkey

1) Decarbonization scenarios are representative of the latest official plans for decarbonizing the power sector by 2053. The scenarios include an annual cap on CO_2 emissions from the power sector in years 2049 and 2050 (set at 35 Mt based on the discussions around the Turkey energy strategy [1]). Similarly, as in previous runs, EPM is run in combined LCP and dispatch model. The main difference with the previous thematic section is that the analysis is not building on top of existing capacity plans but rather develops an optimized decarbonization pathway considering any existing (or under construction) capacity that is expected to be online by 2050. For reducing computational complexity, the temporal aspect of allocation of investments is omitted (aka LCP is assessed and reported for years 2049 and 2050). System expansion considers additional technologies compared to thematic section a) as in the case of CCS and green hydrogen production.
2) Additional scenarios/sensitivities are developed to assess the impact on system performance and costs of key decisions/parameters. These scenarios examine system effects from a) lower CAPEX for electrolyzers, b) accelerated decommissioning of existing coal capacity, c) coordinated EV charging, and d) application of demand response programs.
3) Cost and benefits of above actions are defined through comparative analysis across scenarios.

B. MODELING OF HOURLY EV PROFILE

A basic part of the analysis is disaggregation of annual EV load projections into an hourly EV load which is an input on LCP analysis. This section describes the disaggregation process.[5] The development of hourly EV load profile is based on the following methodological steps:

1) The first step is to estimate the daily EV load per typical use of EVs. Estimation of EV load is based on information related to mileage (km per day) and fuel efficiency (kWh per 100km). It also entails estimates of usage over a weekend versus a weekday (see first 4 columns on Table 3). The final outcome is total electricity requirement separately for a weekday and a weekend day.
2) The second step is estimation of total number of EVs based on (2). Estimation is based on the typical daily load and assumptions related to percentage of EVs being Plug-In Hybrids (PHEV) versus pure electric vehicles. More information related to steps 1 and 2 can be found is section B-1 below.

[4]That way the focus of the analysis is on the interannual effects of PV and wind variability in the system rather on the timing of commissioning of new investments.

[5]It should be noted that the main methodological difference for extracting uncoordinated versus coordinated EV load is the selection of plug-in probability profiles (PPPs) to be discussed later in this section.

3) Finally, the daily load figures are disaggregated into a typical 24-hour profile through a process described in detail in section B-2. The process is largely based on assumptions related to the probability of a vehicle to be connected for charging at a specific time of the 24-hour period. Such information is largely obtained based on real-world published data. Calculations related to EV load profile analysis has been performed using MATLAB. Illustration of assumptions and results of EV load analysis are presented for years 2030 and 2050 for comparative purposes in the following sections.

1) ESTIMATING DAILY ELECTRICITY DEMAND AND TOTAL NUMBER OF ELECTRIC VEHICLES

EV analysis is largely based on World Bank data listed in Table 3. Available data for fuel efficiency and breakdown of BEV versus PHEV are available for the 2020-2030 decade while 2050 projections uses our own assumptions on mileage and fuel efficiency improvements. Average mileage for different type of vehicles has been obtained by publicly available data from the Turkish government [58]. Projected EV load has been obtained by MENR and is presented in table 4. Electricity requirement and total number of EVs has been estimated through (1) and (2):

$$\mathrm{ElecReq}_{VT,EM,WD,y} = \mathrm{FuelEff}_{VT,EM,y} \times \mathrm{Milleage}_{VT,EM,WD,y} \div 100 \tag{1}$$

$$\sum_{EM} NEVM_{VT,EM,y} = \left[EVLoadAnn_y \times 10^9\right] \div \left[\sum_{EM,WD} ElecReq_{VT,EM,WD,y} \times EMBd_{VT,EM,y}\right] \tag{2}$$

2) DEVELOPMENT OF THE HOURLY EV LOAD PROFILE

The main goal of the EV load analysis is the development of the final hourly EV load profile which is based on aggregation of individual profiles of different type of EVs. The final aggregated EV load profile is an input to the LCP analysis. Estimation of EV load is a process performed externally -to and precedes the LCP.

The final aggregated EV load profile, EVloadAg, is the sum of individual load profiles of different types of vehicles (3).

$$\mathrm{EVLoadAg}_{t,WD,CM,y} = \sum_{VT}\sum_{EM}\sum_{CS} \mathrm{EVLoad}_{CS,t,VT,EM,WD,CM,y} \tag{3}$$

Estimation of individual EV load profiles "EVLoad" is based on the following MATLAB script (see (4) to (9)) that includes multiple "for" loops:

An intermediate step to estimation of EVLoad profiles is the calculation of the charging hours matrix, CHM. CHM, contains the number of hours to charge the required energy to cover the daily mileage for each vehicle (see (4)).

$$\mathrm{CHM}_{CS,VT,EM,WD,y} = \mathrm{ElecReq}_{VT,EM,WD,y} \times \left(\frac{1}{\mathrm{CP}_{VT,CS,y}}\right) \tag{4}$$

TABLE 2. Symbols and data used on mathematical description of EV load (outside of EPM) in MATLAB.

Symbol	Description
Y	Year, where y∈Y and Y=y_1, y_2,..y_{NY} where NY is the number of years comprising the study horizon
T	Hour of a day, where t∈T and T=t_1, t_2,..t_{24}
t'	Hour of a 2-day period , where t'∈T' and T'=t'$_1$, t'$_2$,..t'$_{48}$
VT	Vehicle type (VT$_1$:Car, VT$_2$: Taxi, VT$_3$:2-Wheeler, VT$_4$: MiniBus, VT$_5$:Bus, VT$_6$:School Bus VT$_7$:LDV, VT$_8$:HGV)
EM	Electric mode (EM$_1$: EV,EM$_2$: PHEV)
WD	Day of week (WD$_1$: Weekday, WD$_2$: Weekend)
CM	Charging mode (CS$_1$: Uncoordinated, CS$_2$: Coordinated)
CS	Charging speed (CS$_1$: Slow, CS$_2$: Fast, CS$_3$: Rapid)
$\mathrm{EVLoadAnn}_y$	Total EV load in TWh
$\mathrm{Milleage}_{VT,EM,y}$	EV mileage data in km/day
$\mathrm{FuelEff}_{VT,EM,y}$	The efficiency of a vehicle on converting electricity into travelled mileage in kWh of electric input per 100km of travelled distance
$\mathrm{ElecReq}_{VT,EM,y}$	The electrical requirement to travel the daily mileage (kWh/day)
$\mathrm{EMBd}_{VT,EM,y}$	Breakdown of EVs based on electric mode (%)
$\mathrm{NEVM}_{VT,EM,y}$	Matrix with the number of EVs
$\mathrm{CPP}_{CS,t,VT,WD,CM,y}$	Charging probability profile. It is the probability that an EV will be plugged-in at hour t to charge with specific charging speed (%).
$\mathrm{CHM}_{CS,VT,EM,WD,y}$	Charging hours matrix. It is the number of hours to charge the daily electricity requirement
$\mathrm{CP}_{VT,CS,y}$	The charger power capacity (MW) per type of vehicle and charging speed
$\mathrm{HCM}_{CS,VT,y}$	It is the energy that can be delivered to an EV within one hour (kWh/hour). It is equivalent to the capacity of the charger
$\mathrm{EVLoad}_{CS,t,VT,EM,WD,CM,y}$	EV load profile (MW) per type of vehicle, charging mode and charging speed
$\mathrm{EVLoadAg}_{t,WD,CM,y}$	Aggregated EV load profile (MW)
$\mathrm{NEVCM}_{CT,t,VT,EM,WD,CM,y}$	Matrix with number of EVs start charging (plugged-in) at hour t
$\mathrm{EVLoad1}_{t'}$	It is one dimension matrix which acts as a building block for $\mathrm{EVLoad}_{CS,t,VT,EM,WD,CM,y}$ It includes the power drawn by a single EV for each hour over the charging period from the moment an EV was plugged-in
$\mathrm{EVLoad2}_{CS,t',VT,EM,WD,CM,y}$	The 2nd building block for $\mathrm{EVLoad}_{CS,t,VT,EM,WD,CM,y}$ It is the aggregated load over the number of EVs

TABLE 3. Turkey transport sector assumptions for years 2030 and 2050. (Source: world bank ESMAP and MENR.)

	Mileage (km / veh-yr) [a]	% of mileage on a weekend day as comparison to a weekday [b]	Fuel efficiency (kWh/100km)[c]		Estimated electricity requirement (kWh/weekday)		Estimated electricity requirement (kWh/weekend)		Breakdown of total EVs (%) [b]		Breakdown of projected total EV load (TWh) [d]		Estimated number of EVs (000s)	
			2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
Electric Cars	13,325	85%									5.81	76.95	1,716	22,550
Cars-PHEV			17.0	15.3	6.5	5.8	5.5	5.0	26%	0%			445	0
Cars-BEV			28.4	25.6	10.8	9.8	9.2	8.3	74%	100%			1,271	22,550
Electric Taxis	125,000	50%									5.52	73.10	174	2,284
Taxi-PHEV			17.0	15.3	67.8	61.2	33.9	30.6	26%	0%			45	0
Taxi-BEV			28.4	25.6	113.3	102.3	56.7	51.1	74%	100%			129	2,284
2 Wheelers-BEV	3,960	85%	5.0	4.5	0.6	0.5	0.5	0.4	100%	100%	0.29	7.12	5,993	164,482
Mini-Bus	24,636	50%									1.82	22.48	150	2,022
Mini-Bus-PHEV			30.0	27.1	23.6	21.3	11.8	10.7	3%	0%			5	0
Mini-Bus-BEV			50.0	45.1	39.4	35.5	19.7	17.8	97%	100%			145	2,022
Electric Buses	45,100	70%									0.66	8.09	10	131
Buses-PHEV			87.5	79.0	118.2	106.7	82.8	74.7	2%	0%			0	0
Buses-BEV			152.0	137.2	205.4	185.4	143.8	129.8	98%	100%			9	131
Electric School Buses	28,000	0%									1.09	13.49	88	1,142
Buses-PHEV			28.1	25.3	30.1	27.2	0.0	0.0	13%	0%			12	0
Buses-BEV			46.8	42.2	50.2	45.3	0.0	0.0	87%	100%			76	1,142
VANS	25,000	50%									0	56.34	0	11,515
Vans-PHEV			12.3	11.1	9.8	8.9	4.9	4.4	3%	0%			0	0
Vans-BEV			21.7	19.6	17.3	15.6	8.7	7.8	97%	100%			0	11,515
HGVs	40,000	50%									0.07	0.9	2	20
HGVs-PHEV			68.3	61.6	87.2	78.7	43.6	39.4	3%	0%			0	0
HGVs-BEV			122.4	110.5	156.5	141.2	78.2	70.6	97%	100%			1	20

a: Source: Turkish Statistical Institute [58]

b: Source: Authors' assumption

c: World Bank ESMAP

d: MENR

TABLE 4. Projections of EV load per type of vehicle (Source: MENR).

Electricity Demand by mode of transport (TWh)	2030	2050
Total	11.6	136.7
Passenger Cars	6.2	69.6
Buses	2.8	22.6
Motorcycles	1.6	4.0
Freight Transport - Road Transport Light Duty Vehicles	1.0	14.6
Freight Transport - Road Transport Heavy Duty Vehicles	0.0	25.8

for CM = $\mathrm{CM_1{:}CM_2}$
for y = $\mathrm{y_1{:}y_{NY}}$
for WD = $\mathrm{WD_1{:}WD_2}$
for EM = $\mathrm{EM_1{:}EM_2}$
for VT = $\mathrm{VT_1{:}VT_8}$

$$NEVCM_{CS_1:CS_3,t_1:t_{24},VT,EM,WD,CM,y} = NEVM_{VT,EM,y} \times CPP_{CS_1:CS_3,t_1:t_{24},VT,WD,CM,y} \tag{5}$$

for CT = $\mathrm{CT_1{:}CT_3}$
for t = $\mathrm{t_1{:}t_{24}}$

$$\mathrm{EVLoad1}_{t':t'+(\mathrm{floor}(\mathrm{CHM}_{CS,VT,EM,WD,y}))-1} = \mathrm{HCM}_{CS,VT,y} \times \mathrm{NEVCM}_{CT,t,VT,EM,WD,CM,y} \tag{6}$$

$$\mathrm{EVLoad1}_{t:t+(\mathrm{round}(\mathrm{CHM}_{CS,VT,EM,WD,y}),0)))} = \left[\mathrm{CHM}_{CS,VT,EM,WD,y} - \mathrm{floor}\left(\mathrm{CHM}_{CS,VT,EM,WD,y}\right)\right] \times \mathrm{NEVCM}_{CT,t,VT,EM,WD,CM,y} \tag{7}$$

$$\mathrm{EVLoad2}_{CS,t1:t48,VT,EM,WD,CM,y} = \mathrm{EVLoad2}_{CS,t1:t48,VT,EM,WD,CM,y} + \mathrm{EVLoad1}_{t1:t48} \tag{8}$$

end for

$$\mathrm{EVLoad}_{CS,t_1:t_{24},VT,EM,WD,CM,y} = \mathrm{EVLoad2}_{t1:t24} + \mathrm{EVLoad2}_{t25:t48} \tag{9}$$

end for
end for
end for
end for
end for

Equation (5) introduces the number of vehicles that start charging during hour t of the day, NEVCM, based on the total number of EVs, NEVM, and their plug-in probability profiles CPM. Equations (6) and (7) estimate the charging load EVLoad1 for each vehicle for the hours a vehicle is plugged in and charging over a period of 48 hours. It extends beyond 24 hours to estimate the load from vehicles that were plugged in during the end of the day and charging extends over the next day. The total charging load over all different types of vehicles charging with a specific speed over the above 48-hour period is calculated in (8). Finally, in (9) the loads over the two 24-hour periods are superimposed into a single representative day EVLoad representative for each type of EV. The final aggregated EV load matrix, EVLoadAg, defined in (3) includes in total 4 profiles (Uncoordinated vs Coordinated and Weekday vs Weekend) for each year.

3) CHARGING PROBABILITY PROFILES (CPPS)

Estimation of EV load profiles has been based on the mathematical process described above and is largely dependent on assumptions related to charging behaviour which is mathematically represented through the charging probability profiles (CPPs) (refer to (7)).

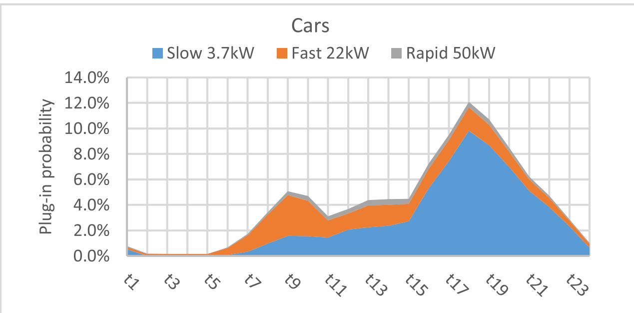

FIGURE 1. CPP from uncoordinated charging of electric cars over a typical weekday in year 2030. It is based on a combination of different uses including individuals charging at home, or at work, or at public charging stations.

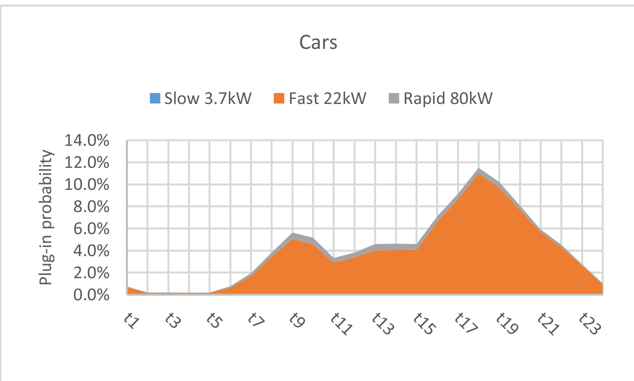

FIGURE 2. CPP from uncoordinated charging of electric cars over a typical weekday in year 2050. The difference with figure 1 is that by 2050 the portion of car owners using fast and rapid charging will overshadow slow charging.

CPPs include information related to the probability that a specific type of vehicle gets connected to be charged at a specific hour of the day as well as the charging technology (charging speed) that is used (see fig. 1 and fig. 2). The development of CPPs has been based on a) plug-in probability profiles (PPPs) and b) assumptions related to the use of charger capacity throughout the study horizon. It is expected that adoption of faster charging will increase with time.

PPPs include information related to the probability that a specific type of vehicle gets connected during a specific hour of the day but are unrelated to the charging speed (see fig. 4). PPPs have been obtained through the published literature focusing on charging behaviour of EV owners. Each PPP is representative of a specific use or service. For example, electric buses could be used for public transportation or as school buses - each use having a different representative PPP. In this study each type of vehicle relates to one or more types of usage (see Table 5). Adoption of faster charging increases with time for all usage.

Over a number of research works, PPP profiles have been obtained for cars, taxis, motorcycles, buses and commercial medium and heavy duty vehicles respectively [42], [43], [51], [59], [60], [61], [62]. PPPs of passenger cars is characterized by two small peaks - one in the morning and a second in the early afternoon, followed by a large early evening peak. The morning peak is mostly related to charging at workplaces; the early afternoon peak is related to residential charging from non-commuters. The large peak is due to post-work (public and residential) overnight charging [42], [43]. Charging of taxis (including ride-hailing services) takes place at depots or at a driver's residence after a shift however rapid charging within the shift has already been observed [59], [63], [63]. Charging of public buses has the highest probability to begin right after the end of the service day and with smaller probability between dayshifts [60], [61]. The electric school bus fleet has a predictable PPP highly dependent on school schedule. School buses have a relative short-service span over a few hours in the morning when collecting students and a few hours in the afternoon to return students to their homes. Most buses are connected for charging after the afternoon ride while a smaller number of school buses is connected for recharge between rides [64]. Commercial charging in this study is mostly related to delivery of goods by medium and heavy-duty vehicles. Interestingly the probability for initiating a commercial charging event is the highest during the middle of the day shift. This is because vehicles charge within rides [65], [66], [67], [68]. Finally commercial long-haul charging behaviour is characterized by overnight driving followed by charging during the day time; data availability on PPPs for commercial long-haul EVs is limited; sources [62], [68] indicate a morning peak at around 10am. Finally, data availability for 2-Wheeler (2-Ws) PPPs is very limited. For this project the 24-hr plug-in probability of 2 wheelers is assumed to be a combination of residential and commercial charging of cars.

Historical real-world data related to coordinated charging are very limited in literature. In this study PPPs of coordinated charging have been developed with the objective of shifting charging towards hours where marginal cost of electricity production is low. However, marginal electricity prices are an output of EPM. While estimation of uncoordinated EV load takes place exogenous to the LCP model, coordinated charging requires running EPM to estimate such periods where marginal cost of electricity production is low. After PPPs for coordinated charging have been developed the LCP is performed again assuming coordinated charging. The process has been based on the following two steps:

a) Estimation of hourly marginal prices for the relevant scenario through running EPM using uncoordinated charging. Identify hours with low marginal prices; and
b) Shifting the probability of the plug-in events (PPPs) towards low-cost hours, also considering constraints related to the timing of operational use of each type of vehicle. Fig. 3 shows an example of developing PPPs for cars of commuters who do not charge at work but rather prefer to charge at home. Running EPM has indicated that electricity prices are high from 5pm to 9pm. Electricity prices are the lowest from 9am to 4pm due to low-cost PV production during those hours; electricity prices are relatively low for the remaining hours 10pm to 8am. For this type of EV use, it is not possible to plug-in during work time. The best option is to shift charging towards late night hours.

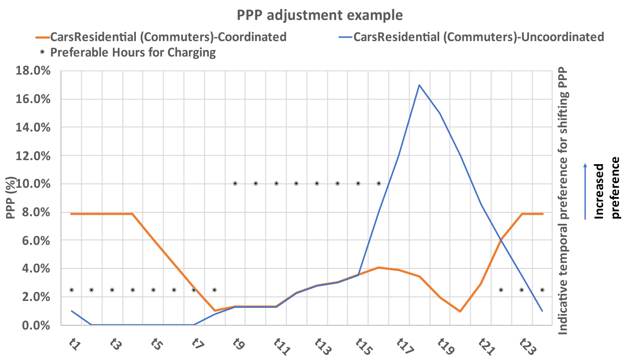

FIGURE 3. Example of adjustment of PPP from uncoordinated to coordinated. Dots represent hours of low system marginal prices.

Fig. 4 and fig. 5 compare PPPs for uncoordinated and coordinated charging respectively for different types of vehicles over a typical weekday.

Using the finalized PPPs as inputs (together with all other inputs from transport sector discussed earlier) and running the MATLAB script which performs calculations defined by (3) to (9), the final EV load can be estimated for both uncoordinated and coordinated charging. Fig. 6 to 9 show the resultant EV load profile for Turkey based on the analysis presented above. Hourly EV load from uncoordinated charging is characterized by an evening peak at 6pm – coinciding with the system demand peak of 162.3GW- mostly driven by private car CPPs. The EV load peak is very high reaching 39.2 GWs. The EV related peak of coordinated charging is also high reaching 38.5 GWs, but it is more skewed towards midday (1pm) creating in fact a new system peak of 159.3GW in 2050. While in absolute terms, reduction of system peak due to coordinated charging is only 3GW, the temporal shift of the peak creates potential for significant economic, operational and emissions related benefits in decarbonization scenarios. The capability of the system to absorb solar power at low cost (without requiring electricity storage) greatly increases which holds very significant cost relief both in terms of reducing the need for peaking capacity in the evening as well as fuel costs.

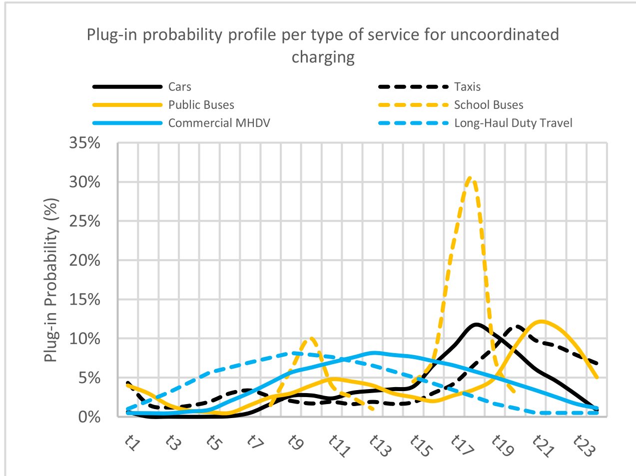

FIGURE 4. Plug-in probability profiles (PPPs) from uncoordinated charging for different type of vehicles over a typical weekday.[7]

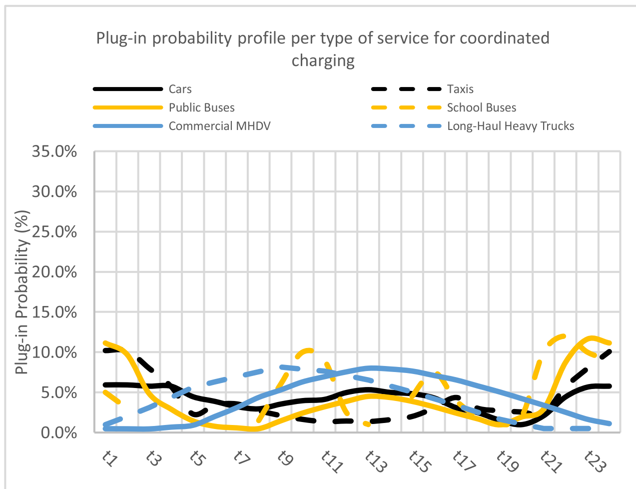

FIGURE 5. Plug-in probability profiles (PPPs) from coordinated charging for different type of vehicles over a typical weekday.

C. MODELING INVESTMENTS ON ELECTROLYZERS AND GREEN HYDROGEN AS A FUEL

Modeling electrolyzer investments and hydrogen fuel use for electricity production endogenously in the model required a

[7]The PPP of cars presented is based on a combination of 4 PPPs namely residential charging of commuters, residential charging of non-commuters, work charging and public charging. Taxi charging is based on 2 PPPs. Charging at depot after the work shift and rapid charging within the shift.

TABLE 5. Example: Relation of EV types and EV use with CPPs for year 2030. Each EV type can relate to more than one CPP.

Type of EV	PPP used	Assumed Charging Capacity (kW)	% of EVs charging with specified PPP and charging speed
1. Private cars	Residential commuters (mostly connect after return from work)	3.7	50%
		22	6%
		50	0%
	Residential non-commuters (charge throughout the day	3.7	13%
		22	1%
		50	0%
	Work charging	3.7	1%
		22	13%
		50	0%
	Public charging	3.7	2%
		22	8%
		50	6%
2.Taxi	Post shift charging	22	90%
	Intra shift charging	50	10%
3.Two-Wheelers	Residential charging	2	40%
	Work charging	2	8%
		15	8%
	Public charging	2	1%
		15	4%
		22	0%
	Commercial charging	15	32%
		22	8%
4. Mini-Buses	Public transportation PPP	22	50%
		50	50%
5. Buses	Public transportation PPP	40	40%
		80	40%
		100	20%
6. School Buses	School bus PPP	22	90%
		50	10%
7. Vans	Commercial short range	7	30%
		22	65%
		50	5%
8. HDVs	Commercial long haul	40	10%
		80	50%
		100	40%

major extension to EPM. A detailed account of all existing equations including the objective function, the transmission network constraints, system requirements, generation constraints, investment constraints, energy storage constraints, environmental policy and time consistency of power system additions and requirements – are reported in [57]. In this section, we present the new equations that constitute the hydrogen production module of EPM.

The PPP of cars presented is based on a combination of 4 PPPs namely residential charging of commuters, residential charging of non-commuters, work charging and public charging. Taxi charging is based on 2 PPPs. Charging at depot after the work shift and rapid charging within the shift.

Equations (10) to (14) represent the time consistency of electrolyzer capacity additions and retirements when EPM is run as a linear model. Equation (10) defines the electrolyzer capacity balance on the first year of the study horizon. Equation (11) defines the capacity balance of existing and committed electrolyzers (Eh) while (12) represents the capacity balance of new electrolyzers (Nh). Equations (13) and (14) put limits on the newly built capacity for committed (Eh) and new electrolyzers (Nh) respectively. In all above cases, capacity additions and retirements are continuous variables. Equations (15) and (16) are activated when EPM is run as a mixed integer programming model. These two equations impose integer limits on new capacity additions or retirements.

$$\begin{aligned} \mathrm{vCap}_{h,y} &= \mathrm{vCap}_{h,y-1} + \mathrm{vBuild}_{h,y} \\ &\quad - \mathrm{vRetire}_{h,y}, \quad \forall (\mathrm{ord}\,(y) = 1, \\ &\quad \forall \left(\mathrm{val}\,(y) > \mathrm{pCommissionYear}_{h}\right) \end{aligned} \tag{10}$$

$$\begin{aligned} \mathrm{vCap}_{h,y} &= \mathrm{pCapacity}_{Eh,y-1} + \mathrm{vBuild}_{h,y} \\ &\quad - \mathrm{vRetire}_{h,y}, \quad \forall (\mathrm{ord}\,(y) > 1, \\ &\quad \forall \left(\mathrm{val}\,(y) > \mathrm{pCommisionYear}_{Eh}\right) \end{aligned} \tag{11}$$

$$\begin{aligned} \mathrm{vCap}_{Nh,y} &= \mathrm{vCap}_{Nh,y-1} + \mathrm{vBuild}_{Nh,y}, \\ &\quad \forall (\mathrm{ord}\,(y) > 1 \end{aligned} \tag{12}$$

$$\sum\nolimits_{y} \left[\mathrm{vBuild}_{Eh,y}\right] = \mathrm{pCapacity}_{Eh},$$

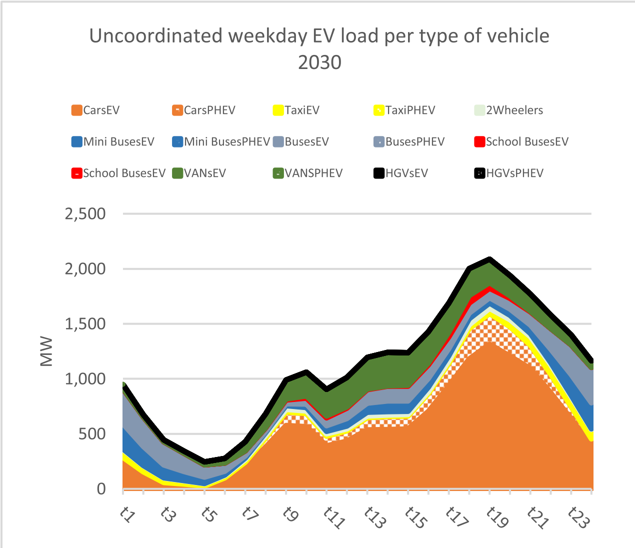

FIGURE 6. EV load profile from uncoordinated charging over a typical weekday of year 2030.

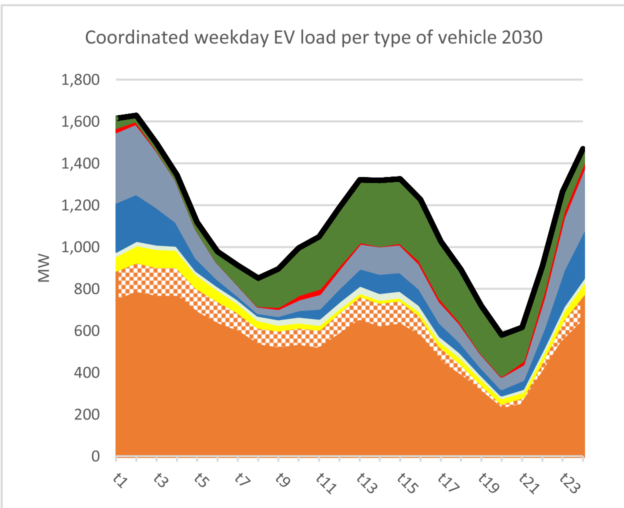

FIGURE 7. EV load profile from coordinated charging over a typical weekday of year 2030.

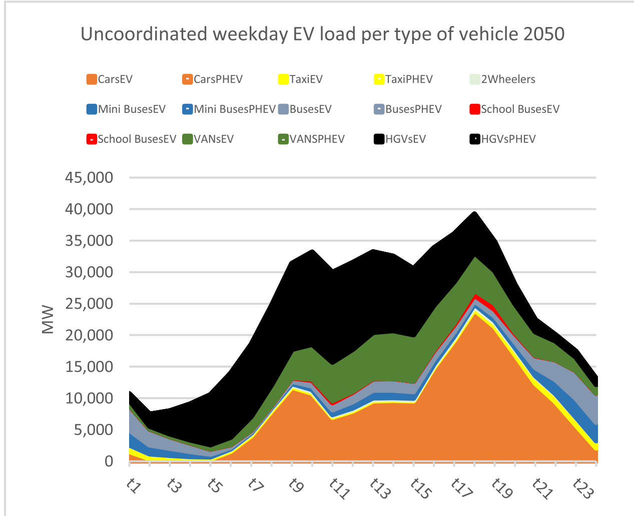

FIGURE 8. EV load profile from uncoordinated charging over a typical weekday of year 2050.

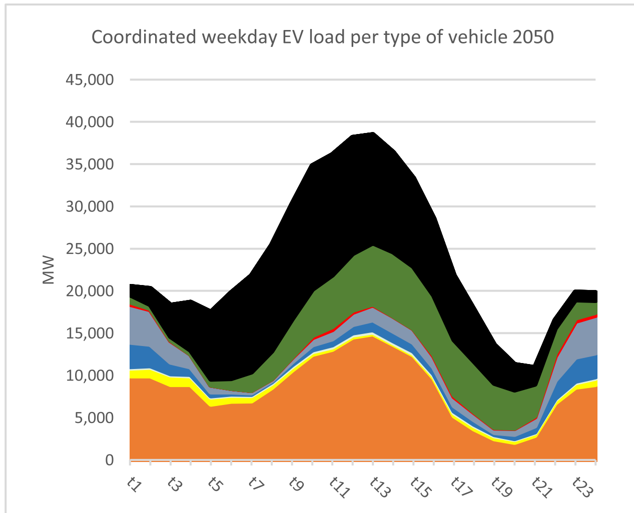

FIGURE 9. EV load profile from coordinated charging over a typical weekday of year 2050.

$$\forall\,(\mathrm{val}\,(\mathrm{y}) > \mathrm{pCommissionYear}_{\mathrm{Eh}}) \tag{13}$$

$$\sum\nolimits_{\mathrm{y}} \left[\mathrm{vBuild}_{\mathrm{Nh,y}}\right] \leq \mathrm{Capacity}_{\mathrm{Nh}} \tag{14}$$

$$\mathrm{vBuild}_{\mathrm{Nh,y}} = \mathrm{pUnitSize}_{\mathrm{Nh}} \times \mathrm{bvBuiltCapVar}_{\mathrm{Nh,y}} \tag{15}$$

$$\mathrm{vRetire}_{\mathrm{Eh,y}} = \mathrm{pUnitSize}_{\mathrm{Eh}} \times \mathrm{bvRetireCapVar}_{\mathrm{Eh,y}} \tag{16}$$

Equations (17) to (20) define the various uses of renewable energy in the power system. Equation (17) describes the breakdown of renewable energy over two main uses, supply of electricity demand and hydrogen production. Equations (18) and (19) aggregate the above two types of electricity use over a zonal level. Equation (20) introduces power injection by electrolyzers and aggregates total power over a zonal level.

$$\begin{aligned}\mathrm{vPwrOut}_{\mathrm{RE,f,q,d,t,y}} &= \mathrm{vREPwr2Grid}_{\mathrm{RE,f,q,d,t,y}} \\ &\quad + \mathrm{vREPwr2H2}_{\mathrm{RE,f,q,d,t,y}}\end{aligned} \tag{17}$$

$$\begin{aligned}&\mathrm{vPwrREGrid}_{\mathrm{z,q,d,t,y}} \\ &\quad = \sum\nolimits_{\mathrm{gfmap(RE,f),gzmap(RE,z)}} \left[\mathrm{vREPwr2Grid}_{\mathrm{RE,f,q,d,t,y}}\right]\end{aligned} \tag{18}$$

$$\begin{aligned}&\mathrm{vPwrREH2}_{\mathrm{z,q,d,t,y}} \\ &\quad = \sum\nolimits_{\mathrm{gfmap(RE,f),gzmap(RE,z)}} \left[\mathrm{vREPwr2H2}_{\mathrm{RE,f,q,d,t,y}}\right]\end{aligned} \tag{19}$$

TABLE 6. Symbols used on mathematical description of hydrogen production in EPM.

Symbol	Type of symbol	Description
h	set	Set of electrolyzers h, where h∈H
y,q,d,t	sets	Sets of years, seasons, days, hours respectively
Eh	set	Subset of existing electrolyzers, where Eh ⊆H
Nh	set	Subset of new electrolyzers, where Nh ⊆H
g	set	Set of electricity producing generators g, where g∈G
f	set	Set of fuels f, where f∈F
RE	set	Set of renewable generators RE, where RE⊆G
gfmap(g,f)	set	Set connecting generator g with fuels for electricity production
gzmap(g,z)	set	Set connecting generator g with zone z that is located
hzmap(h,z)	set	Set connecting electrolyzer h with zone z that is located
sTopology(z, z2)	set	Set of all the possible combinations of two interconnected zones
$bvBuiltCapVar_{Nh,y}$	Binary variable	Variable to impose an integer capacity addition
$bvRetireCapVar_{Nh,y}$	Binary variable	Variable to impose an integer capacity retirement
$vCap_{h,y}$	Continuous variable	Total installed capacity (MW) of electrolyzer h at year y
$vBuild_{h,y}$	Continuous variable	Newly built capacity (MW) of electrolyzer h at year y
$vRetire_{h,y}$	Continuous variable	Retired capacity (MW) of electrolyzer h at year y
$vPwrOut_{g,f,q,d,t,y}$	Continuous variable	Power output (MW) of generator g (including energy storage), burning fuel f, at a specific hour t
$vREPwr2Grid_{RE,f,q,d,t,y}$	Continuous variable	Power from renewable generator RE (MW), using
		renewable resource f that goes to the electricity grid
$vREPwr2H2_{RE,f,q,d,t,y}$	Continuous variable	Power from renewable generator RE (MW), using renewable resource f that is used for production of hydrogen
$vPwrREGrid_{z,q,d,t,y}$	Continuous variable	Total renewable power (MW) within zone z, that goes to the electricity grid
$vPwrREH2_{z,q,d,t,y}$	Continuous variable	Total renewable power (MW) within zone z, that is used for production of hydrogen
$vH2PwrIn_{h,q,d,t,y}$	Continuous variable	Total power (MW) drawn from electrolyzer h for hydrogen production during hour t
$vUnmetExternalH2_{z,q,y}$	Continuous variable	External demand of H2 that was not met (mmBTU) per zone and annum

TABLE 6. *(Continued.)* Symbols used on mathematical description of hydrogen production in EPM.

$vFuelH2_{z,y}$	Continuous variable	The amount of fuel green hydrogen (mmBU) to be used for electricity production per zone and annum
$vFuel_{z,f,y}$	Continuous variable	The amount of fuel that is used for electricity production (mmBTU) per zone and annum
$vFlow_{z,z2,q,d,t,y}$	Continuous variable	Power flows (MW) between two zones over the period of one-time step (hour)
$vStorInj_{st,q,d,t,y}$	Continuous variable	The injected power (MW) by electricity storage device st, over each time step (hour)
$vImportPwr_{z,q,d.t.y}$	Continuous variable	Electricity imports (MW) from other regional grids toward zone z over each time step (hour)
$vExportPwr_{z,q,d,t,y}$	Continuous variable	Electricity exports (MW) from each zone z towards other regional grids over each time step (hour)
$vUSE_{z,q,d.t.y}$	Continuous variable	Unserved power (MW) per zone over each time step (hour)
$vSurplus_{z,q,d.t.y}$	Continuous variable	Surplus power (MW) per zone over each time step (hour)
$vAnnCapexH2_{h,y}$	Continuous variable	The annualized CAPEX of electrolyzers per annum ($)
$vH2FixedCost_{z,y}$	Continuous variable	The total fixed costs of electrolyzers per zone ($)
$vH2VariableCost_{z,y}$	Continuous variable	The total variable cost of hydrogen production per zone ($)
$pHours_{q,d,t,y}$	parameter	The number of hours comprising one time step
$pCommissionYear_{h}$	parameter	Earliest commissioning year of candidate electrolyzer Nh / commissioning year of committed generator Eh
$pCapacity_{h}$	parameter	The maximum electrolyzer capacity installed (MW)
$pUnitSize_{h}$	parameter	The unit size (MW) of electrolyzer plant h
$pAvailability_{h,q}$	parameter	The seasonal (monthly) availability of electrolyzers (%)
$pExternalH2_{z,q,y}$	parameter	External demand of green hydrogen to be produced by the power sector for decarbonization of other sectors per zone and year (mmBTU)
$pH2ConvRate_{h}$	parameter	The conversion rate of hydrogen production per electrolyzer (mmBTU of H2 per MWh of electricity)
$pH2CAPEX_{h}$	parameter	The overnight CAPEX of electrolyzers in USD/MW
$pCAPEXTrajectoryH2_{h,y}$	parameter	Annual CAPEX reduction factor (%) relative to CAPEX at the beginning of the optimization horizon

TABLE 6. ***(Continued.)*** **Symbols used on mathematical description of hydrogen production in EPM.**

$\mathrm{vH2FOM_h}$	parameter	The FOM costs of electrolyzers in \$/MW/yr
$\mathrm{vH2VOM_h}$	parameter	The VOM costs of H2 production in \$/mmBTU
$\mathrm{pCRF_h}$	parameter	Capital recovery factor of each electrolyzer (depends on WACC and technical lifetime)
$\mathrm{pDemandData_{z,q,d.t.y}}$	parameter	The zonal electricity demand (MW) over each time step (hour)
$\mathrm{pLossFactor_{z,z2,y}}$	parameter	The transmission losses between two zones (% of power flow)
ord(y)	operator	The order of year y over the study horizon, (i.e 1st, 2nd, 3rd.. etc)
val(y)	operator	The numerical value of year y (i.e 2022, 2023, 2040, .. 2050 etc)

$$\sum\nolimits_{\mathrm{hzmap(h,z)}} \left[\mathrm{vH2PwrIn_{h,q,d,t,y}}\right] = \mathrm{vPwrREH2_{z,q,d,t,y}} \quad (20)$$

Equations (21) and (22) place operational limits on electrolyzers. Equation (21) places a seasonal limit on electrolyzer availability while equation (22) places an upper limit on power drawn by each electrolyzer.

$$\begin{aligned}\sum\nolimits_{\mathrm{d,t}} \left[\mathrm{pHours_{q,d,t,y}} \times \mathrm{vH2PwrIn_{h,q,d,t,y}}\right] &\leq \mathrm{pAvailability_{h,q}} \times \mathrm{vCap_{h,y}} \\ &\quad \times \sum\nolimits_{\mathrm{d,t}} \left[\mathrm{pHours_{q,d,t,y}}\right] \quad (21)\\ \mathrm{vH2PwrIn_{h,q,d.t.y}} &\leq \mathrm{vCapH2_{h,y}} \quad (22)\end{aligned}$$

Equations (23) and (24) introduce hydrogen as a fuel for electricity production. Equation (23) adds hydrogen in the pool of fuels for electricity production via the $vFuel_{z,f,y}$ variable. Equation (23) also puts a limit on the amount of H_2 that can be burned in gas turbines based on the amount that it has been produced on an annual basis. Equation (24) aggregates total seasonal hydrogen production into an annual value.

$$\sum\nolimits_{\mathrm{z}} \left[\mathrm{vFuel_{z,f=H2,y}}\right] = \sum\nolimits_{\mathrm{z}} \left[\mathrm{vFuelH2_{z,y}}\right] \quad (23)$$

$$\sum\nolimits_{\mathrm{q}} \left[\mathrm{vFuelH2Season_{z,q,y}}\right] = \mathrm{vFuelH2_{z,y}} \quad (24)$$

Equations (25) and (26) introduce an exogenous hydrogen demand for decarbonization of other sectors. Equation (25) disaggregates total green hydrogen produced at the electrolyzers in two elements, namely, hydrogen to be used for electricity production; and hydrogen to be used in other sectors. Variable $vUnmetExternalH2_{z,q,y}$ represents unserved external hydrogen demand which incurs an economic penalty described in (27). Equation (26) places an upper limit on the amount of $vUnmetExternalH2_{z,q,y}$.

$$\begin{aligned}&\mathrm{pExternalH2_{z,q,y}} - \mathrm{vUnmetExternalH2_{z,q,y}} + \mathrm{vFuelH2Season_{z,q,y}}\\ &\quad = \sum\nolimits_{\mathrm{hzmap(h,z)}} \left[\mathrm{vH2PwrIn_{h,q,d,t,y}} \times \mathrm{pHours_{q,d,t,y}} \times \mathrm{pH2ConvRate_h}\right] \quad (25)\end{aligned}$$

$$\mathrm{vUnmetExternalH2_{z,q,y}} \leq \mathrm{pExternalH2_{z,q,y}} \quad (26)$$

$$\mathrm{vH2UnservedCost_{h,q,d.t.y}} = \sum\nolimits_{\mathrm{q}} \left[\mathrm{vUnmetExternalH2_{z,q,y}}\right] \times \mathrm{pH2UnservedCost} \quad (27)$$

Equation (28) shows the demand supply balance that accounts for the additional electricity demand for hydrogen production.

$$\begin{aligned}\mathrm{pDemandData_{z,q,d.t.y}} &= \sum\nolimits_{\mathrm{gfmap(RE,f),gzmap(RE,z)}} \left[\mathrm{vPwrOut_{g,f,q,d,t,y}}\right]\\ &\quad - \sum\nolimits_{\mathrm{hzmap(h,z)}} \left[\mathrm{vH2PwrIn_{h,q,d,t,y}}\right]\\ &\quad - \sum\nolimits_{\mathrm{sTopology(z,z2)}} \left[\mathrm{vFlow_{z,z2,q,d,t,y}}\right]\\ &\quad + \sum\nolimits_{\mathrm{sTopology(z,z2)}} \left[\mathrm{vFlow_{z2,z,q,d,t,y}}\right] \times \left(1 - \mathrm{pLossFactor_{z,z2,y}}\right)\\ &\quad - \sum\nolimits_{\mathrm{gzmap(g,z)}} \left[\mathrm{vStorInj_{st,q,d,t,y}}\right]\\ &\quad + \mathrm{vImportPwr_{z,q,d.t.y}} - \mathrm{vExportPwr_{z,q,d.t.y}}\\ &\quad + \mathrm{vUSE_{z,q,d.t.y}} - \mathrm{vSurplus_{z,q,d.t.y}} \quad (28)\end{aligned}$$

Equations (29) to (31) introduce the annualized CAPEX and total variable and fixed costs related to green hydrogen production and use. Elements $\mathrm{vH2FixedCost_{z,y}}$ and $\mathrm{vH2VariableCost_{z,y}}$ of Equations (30) and (31) have been added into the objective function of the main EPM code to integrate hydrogen related cost into system wide costs.

$$\begin{aligned}\mathrm{vAnnCapexH2_{h,y}} &= \mathrm{vAnnCapexH2_{h,y-1+}vBuild_{h,,y}} \times \mathrm{pH2CAPEX_h}\\ &\quad \times \mathrm{pCAPEXTrajectoryH2_{h,y}} \times \mathrm{pCRF_h} \quad (29)\end{aligned}$$

$$\begin{aligned}\mathbf{vH2FixedCost_{z,y}} &= \sum\nolimits_{\mathbf{hzmap(h,z)}} \left[\mathbf{vAnnCapexH2_{h,y}} + \mathbf{vCap_{h,y}} \times \mathbf{vH2FOM_h}\right] \quad (30)\end{aligned}$$

$$\begin{aligned}\mathbf{vH2VariableCost_{z,y}} &= \sum\nolimits_{\mathbf{hzmap(h,z)}} \left[\mathbf{pVOMH2_h} \times \mathbf{pH2ConvRate_h}\right.\\ &\quad \left.\times \mathbf{vH2FOM_h} \times \mathbf{vH2PwrIn_{h,q,d.t.y}} \times \mathbf{pHours_{q,d,t,y}}\right] \quad (31)\end{aligned}$$

V. SCENARIOS AND MAIN ASSUMPTIONS

The analysis is structured around five key scenarios. All scenarios use the same demand projections in energy terms; and all scenarios account for EV charging. However, the shape of the demand profile depends on whether EV charging is uncoordinated or coordinated. The first two scenarios are built around the Baseline plan (see table 7) which is representative of moderate CO_2 reduction ambitions (i.e., 33% of VRE in 2050). Scenarios 1 and 2 assume uncoordinated EV charging. Scenarios 3 to 5 were developed to support the development of a decarbonization pathway considering additional technologies (relative to scenarios 1 and 2). Such technologies include electrolyzers for production of green hydrogen, demand response and Carbon Capture and Storage (CCS). Scenario 5 is the only one which considers coordinated EV charging. In all scenarios (1 to 5) the combined LCP and dispatch simulations are performed for years 2049 and 2050. The reason for simulating two consecutive years is to account for VRE uncertainty by using representative historical data from both average and low VRE resource years. A more detailed description of scenarios and related assumptions follows below:

Scenario 1: The goal of the Baseline scenario is to assess if the incumbent capacity plan presents energy and/or capacity adequacy issues. The Baseline is characterized by moderate CO_2 reduction ambition, having as a main goal to achieve 33% of solar and wind energy by 2050. It also assumes hydro economic potential of around 36GW will be utilized by 2030.

TABLE 7. Draft capacity plan for the baseline scenarios (1 and 2).

	Expected Generation (TWh)	Capacity Plan (GW)
Generation (TWh)	**2050**	**2050**
Total	957	233
Nuclear	74	10
Coal	103	16
Hard Coal	59	9
Lignite	44	7
Gas	357	34
CCGT	335	45
OCGT	21	11
Renewables	423	174
Hydro	93	36
Wind	202	67
Solar	118	67
Other	10	3
Share of Wind &Solar	33.4%	

The assessment is based on dispatch simulations wherein no additional capacity additions are allowed. Generation adequacy for the system is assessed using relevant indicators like loss of load, generation, provision of reserves, and system capacity reserve.

Scenario 2: The goal of scenario 2 is to assess the optimal capacity additions which are needed to bridge any adequacy gaps identified in scenario 1 through combined dispatch and LCP simulations. System adequacy is driven by an economic penalty for failing to supply required energy and/or operational reserves and/or system need for capacity reserves. The base capacity plan can be supplemented with PV, wind, combined cycle gas turbines (CCGTs), open-cycle gas turbines (OCGTs), battery electricity storage systems (BESS) and pumped hydro plants (PHPs). Uncoordinated EV charging is assumed.

Scenario 3: This Decarbonization scenario is developed to estimate the least-cost plan subject to system constraints and policy obligations. System optimization takes place through combined dispatch simulations and LCP subject to same system constraints described in scenario 2. The main policy constraint considered by the model is a cap on systemwide CO_2 emissions at 35 million tonnes in year 2050. The scenario considers the remaining existing and planned capacity that will still be online by 2050 based on information by MENR (see table 8). Any additional investments are optimized on top of this fixed capacity. In addition, the LCP considers investments in electrolyzers for green hydrogen production and CCS. Electrolyzer capacity and operation is subject to optimization. This means that green hydrogen in scenario 3 becomes part of the capacity plan if it causes a reduction on total system cost. This can happen if the additional CAPEX (of electrolyzers and additional VRE) is lower than the reduction in use of fossil fuels. However, the scenario includes a target for green hydrogen and synthetic methane gas (SNG) production to support decarbonization of other sectors. This constraint imposes some capacity of electrolyzer to be built as mandatory. More detailed discussion on electrolyzer related assumptions follows on section V-III. The above assumptions are also applied on all following scenarios.

TABLE 8. Fixed capacity in scenarios 3 to 5.

Installed Capacity (GW) = Current Capacity + Existing Projects – Decommissioning	2050
Total	55.7
Nuclear	4.8
Coal	8.9
Hard Coal	6.8
Lignite	2.1
Gas	4.8
CCGT	4.8
OCGT	0.0
Renewables	37.2
Hydro	36.0
Hydro-Storage	25.0
Hydro-RoR	11.0
Wind	0.0
Solar	0.0
Other	1.2

Scenario 3a is a sensitivity on fixed costs of green hydrogen production. This scenario intends to assess if adopting optimistic cost projections on electrolyzer CAPEX could have a significant impact on the capacity plan in the Decarbonization scenario.

Scenario 3b aims to assess the system needs for natural gas, VRE and electrolyzers, excluding coal from analysis. The main assumption in this scenario is that existing or planned capacity on coal will be decommissioned by 2050.

Scenario 4: The goal of this scenario is to assess any economic and operational benefits of demand response (DR). Inclusion of DR is the only difference compared to scenario 3. DR is modelled as flexible demand where reduction is associated with some costs. The optimal amount of demand response depends on its net benefit and is limited by power and energy limits (see section V.5)

Scenario 5: This scenario was developed to assess any economic and operational benefits from coordinated EV charging. From an analytical perspective, the only difference with scenario 4 is the profile of electricity demand. Any technological costs or other types of costs related to coordinated charging are not accounted for in the analysis. The main benefits for the system are related to shifting the peak towards midday, which increases absorption of solar power and the capacity credit of PV in the system. This translates into lower costs for PV and higher contribution of solar into system firm capacity.

The following assumptions have been made to articulate the scenarios:

1) ELECTRICITY DEMAND

Table 9 shows demand projections based on MENR. Net demand in table 9 represents aggregate electric demand from sectors other than transport (blue color in fig. 10 and fig. 11). While the estimated level of electrification in residential, industry and services sectors is included as part of annual projections, the impact of transport electrification on the shape of demand is explicitly considered as part of this study. This is important as EV load is expected to contribute up to 19% of total electricity demand by 2050.

TABLE 9. Electricity demand projections (Source: MENR).

Electricity Demand (TWh)	2020	2030	2040	2050
Total (Net)	294	423	572	744
Transport	1	12	60	137
Total (Net) without transport demand	293	412	511	607

The shape of load for sectors other than transport has been estimated by scaling up historical hourly electricity demand data from year 2017 (blue area on fig. 10 and fig. 11) and it is the same across all scenarios. When we add on top of non-EV load the uncoordinated EV load (red area on fig. 10), the combined peak of 162.3GW occurs at 6pm (fig. 10). Coordinated EV charging shifts the combined system peak of 159.3GW to 1pm (fig 11). Estimation of EV load profile through the process described in section IV-B is exogenous to the LCP and the combined hourly EV load is an input on EPM. The EV load profile analysis also shows the level of deviation in magnitude and temporal occurrence of the peak by comparing it to the combined load if it were estimated through the simplified process of scaling up historical profiles (see black line on fig. 10 and fig. 11). The system peak considering uncoordinated and coordinated EV load analysis is larger by 7GW and 4.2GW, respectively, compared to the simplified approach of scaling historical demand which is widely used in LCP analysis. This is indicative for the need to account for the effects of electrification on system load in decarbonization LCP analysis. It should be noted that figures 10 and 11 show a single day of electricity demand which is an input to EPM. The additional electricity demand for green hydrogen production is subject to optimization (electrolyzer operation is optimized by EPM) and not shown in fig. 10 and fig. 11. The additional contribution of electrolyzer operation on system demand is discussed on results section.

2) TECHNOECONOMIC INFORMATION OF GENERATORS, ELECTRICITY STORAGE AND ELECTROLYZERS

Tables 10 to 12 present assumptions of main techno-economic parameters used as inputs to EPM for electricity generating technologies, electricity storage and electrolyzers, respectively. Costs of candidate technologies for generators and electricity storage are estimates for year 2035 which is the mid-point over the study period 2023-2050. Estimates for electrolyzers are for year 2050 based on the assumption that electrolyzers will be economic for the system towards the end of the study horizon due to stringent CO2 cap and high VRE penetration.

Assumptions on table 10 are based on MENR estimates. Storage assumptions presented on tables 10 and 11 are based on NREL and PNNL respectively [69], [70]. Pumped hydro is assumed to have fixed storage discharge time of 10 hours while the discharge time of BESS is optimized.

Table 12 shows estimates of techno-economic parameters of Alkaline electrolyzers in 2050. Electrolyzers are assumed to have 80% efficiency and a CAPEX of 200,000 USD per MW. Fixed operation and maintenance (FOM) costs are assumed to be 4% of CAPEX while variable O&M (VOM) covers the cost of water and compression. In scenario 3a, CAPEX costs are assumed to be reduced by 12.5% representing more optimistic projections [71], [72], [73], [74]. It should be noted that the cost of electricity to run electrolyzers is not accounted for since this work is based on system wide economic analysis The cost of electricity to run electrolyzers is indirectly accounted in the LCP as RE related CAPEX and OPEX. If for example electrolyzers are run through -otherwise- curtailed VRE the cost of electrolyzer electricity is nearly zero.

3) PRODUCTON OF GREEN HYDROGEN AND SNG

In our modelling construct, green hydrogen can be used directly or be converted into synthetic methane (SNG)

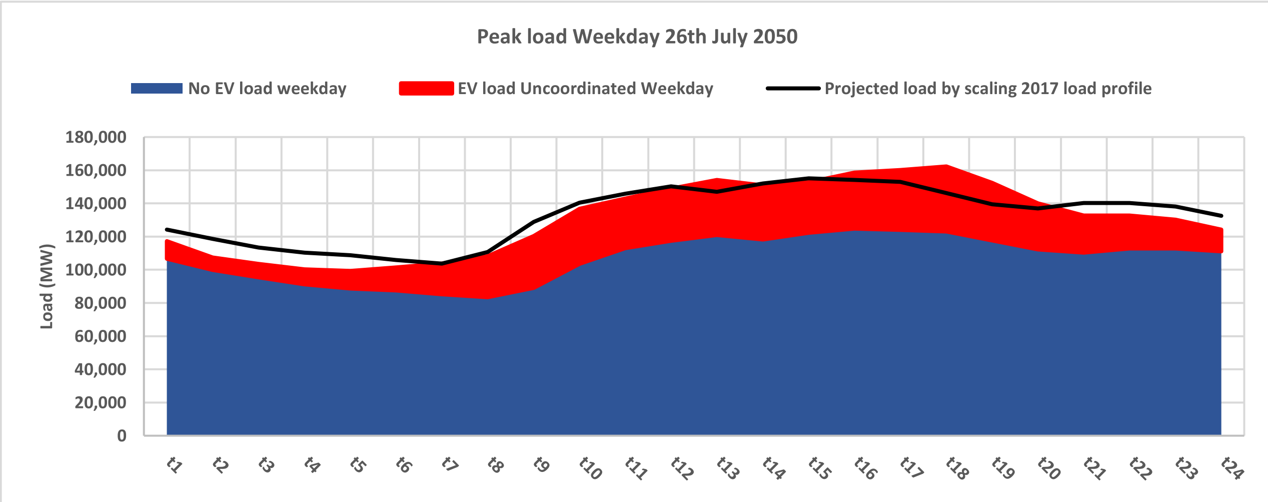

FIGURE 10. **Electricity demand during the day of the peak load in year 2050. The colored area is the electricity demand used in this analysis disaggregated into non-EV demand and uncoordinated EV related demand. The black line is the system wide electricity demand without accounting of analysis of EV load profile (EV load that would have been estimated by scaling 2017 demand; illustrated in the graph but not used in analysis).**

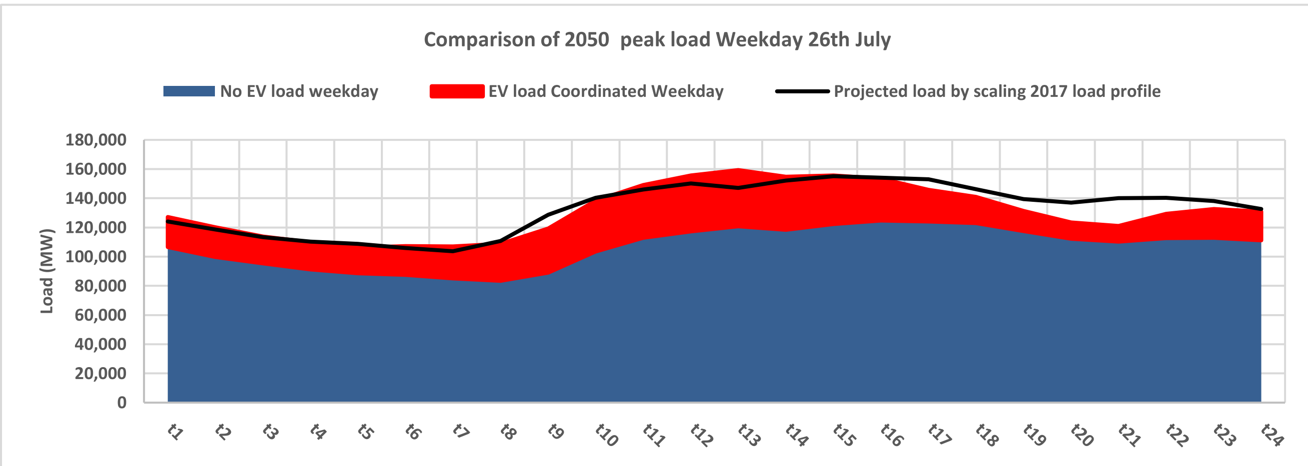

FIGURE 11. **Electricity demand during the day of the peak load in year 2050. The colored area is the electricity demand used in this analysis disaggregated into non-EV demand and coordinated EV related demand.**

i.e., power to gas (P2G). The combined final efficiency of P2G process is 62% which combines 80% efficiency from electrolysis, 80% efficiency for the methanation process and around 2% of losses on compression [75] (fig. 12). Techno-economic assumptions related to P2G plants are listed in table 12.

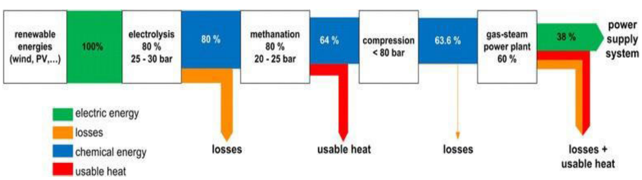

FIGURE 12. **Sankey diagram for P2G process (Source: [75]).**

Production of green hydrogen is assumed to be a) recirculated back to the power sector for electricity production essentially using green hydrogen as a long-term storage; or b) used in other sectors. The latter case is modeled as a mandatory external demand of green hydrogen and SNG to be produced by the power system. The external 2050 green hydrogen and SNG demand estimates from MENR are 20TWh and 143TWh, respectively. Green hydrogen and SNG for electricity production (i.e., recirculation to power sector) is determined endogenously in EPM. The following assumptions have been made:

- Green hydrogen can be burned directly as fuel by conventional existing, or new OCGT and/or CCGT if mixed at 20% per volume with natural gas and/or SNG;
- Pure green hydrogen can be burned directly by new OCGTs and/or CCGTs modified for hydrogen fuel; and
- Pure SNG can be used directly by conventional existing or new turbines.

Assumptions related to modified gas turbines for hydrogen are listed on table 10. Fixed and variable costs are assumed

TABLE 10. Techno-economic parameters of electricity generating technologies used as inputs on EPM. (Technologies without capex represent capacity that is expected to be part of the system but not optimized.)

Plants	Fuel	Heat Rate (mmBTU/ MWh)	FOM ($/MW/year)	VOM ($/MWh)	CAPEX ($ million /MW)	Project life time	Ramp rate (up)	Ramp rate (down)	Capacity contribution to operational reserves (%)
NUCLEAR	Uranium	10.3	139,000	7.5		60	50%	50%	12%
HARD COAL	Imported Coal	8.1	45,000	3.5		40	60%	60%	17%
LIGNITE	Lignite	8.1	45,000	4.0		40	60%	60%	16%
COAL with CCS	Hard Coal	9.4	118,000	4.0	4.1	40	50%	50%	17%
GEOTHERMAL	Geo Energy		47,500	0.3	2.5	30	30%	30%	2%
CCGT	Natural Gas	5.7	22,500	2.0	0.8	30	100%	100%	70%
OCGT	Natural Gas	8.4	20,000	2.0	0.4	30	100%	100%	99%
CCGT with CCS	Natural Gas	6.8	58,000	2.0	2.5	30	100%	100%	70%
CCGT (Hydrogen)	Hydrogen	6.2	22,500	2.0	0.8	35	100%	100%	70%
OCGT (Hydrogen)	Hydrogen	9.1	20,000	2.0	0.4	25	100%	100%	99%
HYDRO STORAGE	Water		40,000	0.5		60	100%	100%	7%
RUN OF RIVER	Water		40,000	0.0		60	100%	100%	0%
WIND	Wind		31,500	0.0	1.3	25	100%	100%	0%
SOLAR PV	Solar		11,000		0.6	25	100%	100%	0%
BIOFUEL PLANT	Biomass	14.0	63,000	2.5	2.0	35	100%	100%	17%
BESS		Efficiency (90%)	17,500	0.0	0.1	15	100%	100%	100%
PHP		Efficiency (78%)	15,900	0.0	0.9	60	100%	100%	100%

TABLE 11. Techno-economic parameters of electricity storage technologies used as inputs on EPM.

Storage Plant	CAPEX ($ / kWh)	CAPEX ($ million/MW)	VOM ($/MWh)	FOM ($/MW/year)	Efficiency	Project lifetime
BESS	125	0.1	0	17,500	90%	15
PSH_Cand (10hr storage)		0.92	0	15,900	78%	60

TABLE 12. Techno-economic parameters of electrolyzers used as inputs on EPM.

Type of Electrolyzer	Scenario	Efficiency (%) in 2050	2050 CAPEX ($m/MW)	FOM (% of CAPEX)	FOM ($/MW)	VOM (Cost of electricity) ($/MWh)	VOM (Cost of water ($/kg-H2)	VOM (Cost of H2 compression) ($/kg-H2)	VOM (Cost of methanat-ion) ($/mmBTU -SNG)	VOM total ($/ mmBTU-H2 (or SNG))	Project life-time (years)
Alkaline (AE)	Average	80.0%	0.2	4%	8,000	0	0.08	0.4		4.2	13
	Optimistic	80.0%	0.175	4%	7,000	0	0.08	0.4		4.2	13
P2G	Average	62%	0.4	4%	16,000	0	0.08	0.4	0.8	5	13
	Optimistic	62%	0.375	4%	15,000	0	0.08	0.4	0.8	5	13

to be similar to those of conventional gas generators [76]. Due to NOx control issues hydrogen turbines are assumed to have lower efficiency compared to conventional technologies [77], [78].

4) FUEL COSTS AND EMISSIONS FACTORS

Assumptions related to fuel costs and emissions are presented on table 13.

5) MODELING DEMAND RESPONSE

Demand response is modeled as flexible load with a cost of $80 per MWh reduction. Maximum reduction (in GW) within one hour is equal to 10% of the annual peak (nearly 16GW). Demand response is limited to a maximum of 100 hours per year.

6) RE RESOURCE DATA

Actual historical timeseries of hourly capacity factors of RE production from years 2016-2021 were obtained from MENR. This is used to represent resource constraints and construct RE scenarios. VRE production (PV, wind and RoR) in EPM is modeled based on historical hourly generation. When VRE cannot be absorbed, it is curtailed incurring an assumed penalty of $60/MWh. Hydro storage production is optimized within each month; however the monthly capacity factor is constrained based on the historical figures.

TABLE 13. Fuel cost assumptions used as inputs on EPM.

	Emissions factor (ton CO2 / mmBTU)	Fuel costs ($/mmBTU)
Fuel	**2049 and 2050**	
Uranium	0	0.4
Hard coal	0.097	2.7
Lignite	0.097	2.7
Biomass	0	5.3
Natural gas	0.054	8.4
Nat. Gas_H2 Mix	0.050	7.9
Hydrogen	0	0
SNG	0	0
SNG_H2 Mix	0	0

The choice of representative years is made based on statistical analysis and in collaboration with MENR. Average resource year for all three resources (hydro, solar and wind) happened to occur in 2020. Low resource year for hydro (both RoR and storage) is 2021, while for PV and wind it is the year 2018 (fig. 13 to 15).

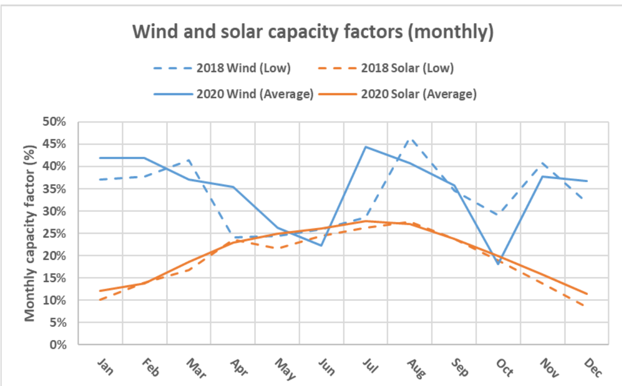

FIGURE 13. Monthly capacity factors of wind and PV inputs.

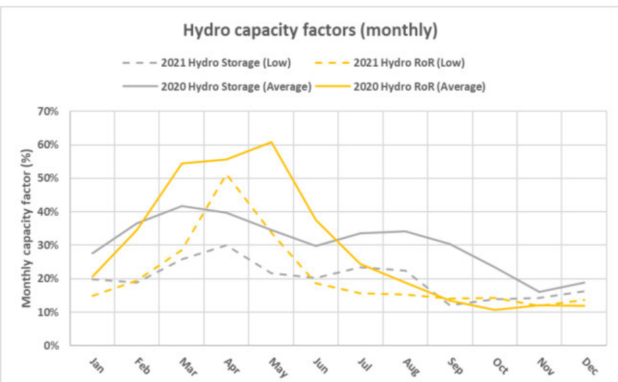

FIGURE 14. Monthly capacity factors for hydro storage and hydro RoR inputs.

7) SYSTEM NON-SYNCHRONOUS PENTRATION LIMIT

A power system's ability to absorb non-synchronous generation from solar and wind is limited due to system security issues. Very high instantaneous generation from VRE limits a system's ability to recover effectively from contingencies. There are measures to increase a system's ability to absorb very high shares of VRE albeit these issues are beyond the scope of this paper [79].

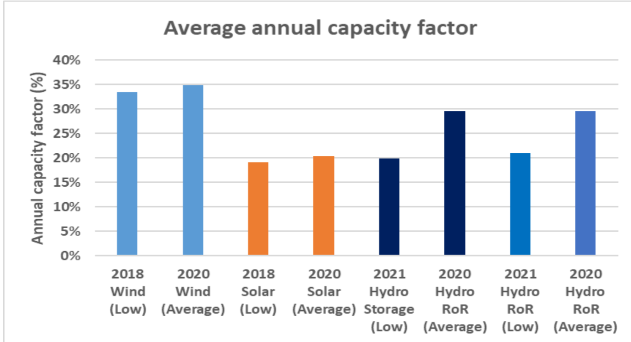

FIGURE 15. Annual capacity factors for wind, PV, hydro storage and hydro RoR.

The EPM Turkey model includes an instantaneous system non-synchronous penetration (SNSP) limit of 80% for years 2049 and 2050. The SNSP assumption was made in collaboration with MENR. The SNSP limit is defined as the sum of non-synchronous generation over total generation and is applied for each hour of operation [80].

8) POLICY GOALS

In scenarios 1 and 2 there is a constraint of 33% generation from PV and wind at minimum in 2049 and 2050. In decarbonization scenarios there is a system cap on CO_2 emissions for a maximum of 38 and 35 million tons of CO_2 in 2049 and 2050, respectively. The CO_2 cap is not a hard constraint in EPM. The model includes a penalty for breaching the CO_2 cap at $300 per ton. This reflects the cost the society would bear for utilizing some backstop technology to mitigate CO_2 impacts.

VI. RESULTS

The first part of analysis focuses on system reliability of the Baseline plan. In the Baseline, the system experiences loss of load at various instances throughout the year (fig. 16)

Loss of load varies across the months/seasons (fig. 17). Both occurence and magnitude of loss of load are higher over September to February, affected by lower capacity factors of hydro and solar generation (fig. 13 and fig. 14) and also in July, when peak demand of the year occurs. In addition, as expected, loss of load is higher in a year with low RE resource compared to average conditions. Simulations indicate that loss of load witin a low RE year fluctuates between around 0.5% and 6% of monthly generation while over an average year the range becomes 0% - 2% (fig. 18). These are clearly too high that breaches most reliability standards including that for Turkey.

Another metric to measure system reliability is the generation reserve margin expressed in terms of available

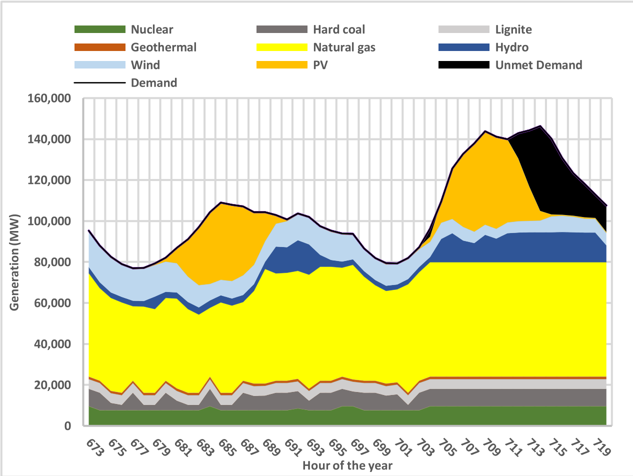

FIGURE 16. Example of optimized dispatch over the 29th and 30th of January 2050 (Scenario 1).

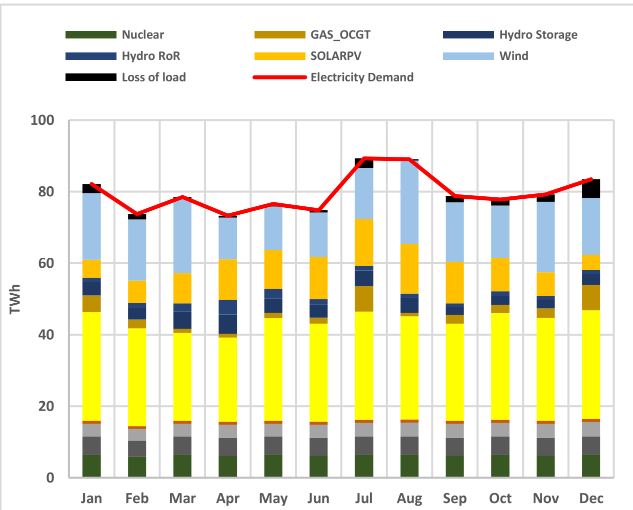

FIGURE 17. Optimized monthly generation and loss of load for year 2050 (Scenario 1).

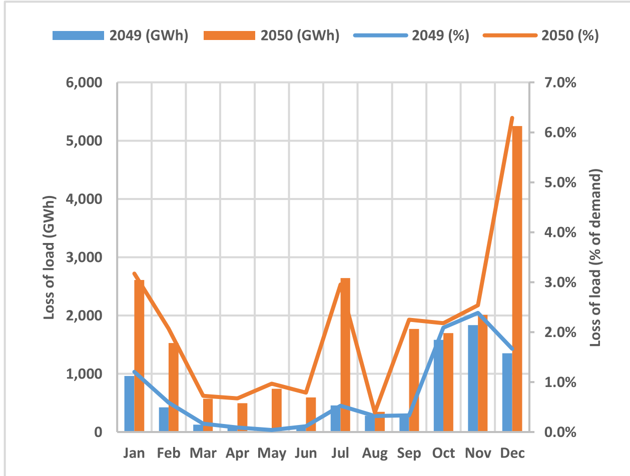

FIGURE 18. Comparison of loss of load for years 2049 (average RE) and 2050 (low RE) based on simulated system operation (Scenario 1).

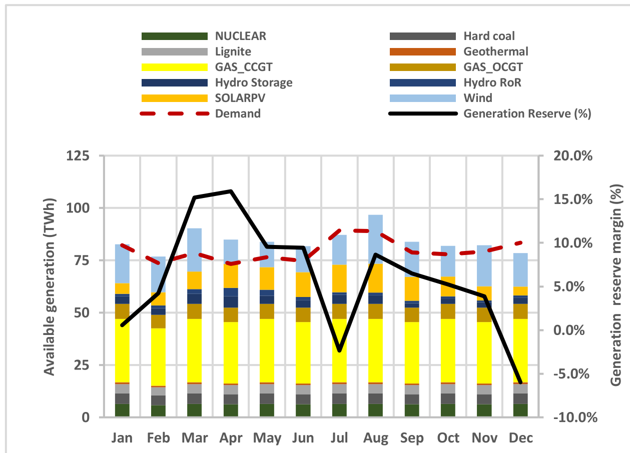

FIGURE 19. Generation availability and generation reserve margin per month in year 2050 (Scenario 1).

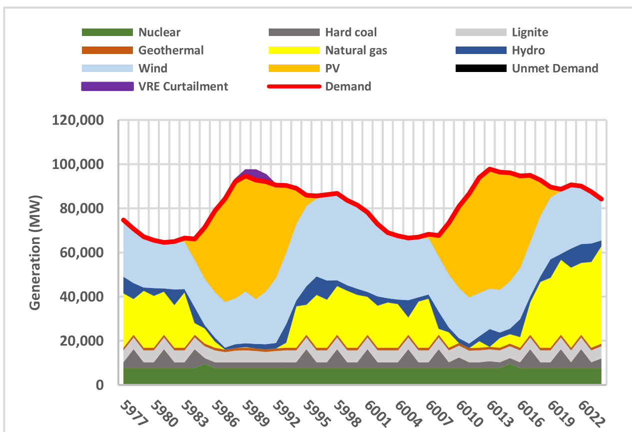

FIGURE 20. Two days dispatch indicative of increased cycling of coal and VRE curtailment (Scenario 1).

generation (considering capacity factors and historical availability) minus demand divided by demand. As an example a system where available generation is 110TWh and demand is 100TWh will have generation reserve margin of 10%. Fig. 19 shows generation availability and reserve margin over a year with low RE resource. It can be observed that generation availability falls short of demand only in July and December while the system experiences loss of load over a larger period as discussed earlier. The reason the system can not absorb all available energy is due to system flexibility limitations caused by ramping and the SNSP constraints. Fig. 20 shows an example of two days dispatch where variation of RE creates extensive cycling of coal generation and at the same time SNSP causes curtailment of VRE.

The above observations indicate that a system with positive generation reserve margin could still experience loss of load if it lacks flexibility. A system, however, with negative generation reseve margin will always experience loss of load. Simulations indicate that the system experiences a range of months (July to February) with low generation reserve margin (below 10%) in both high and low RE resource years. The system experiences negative generation reserve margin in July and December in low RE years and in October over an average year (fig. 21).

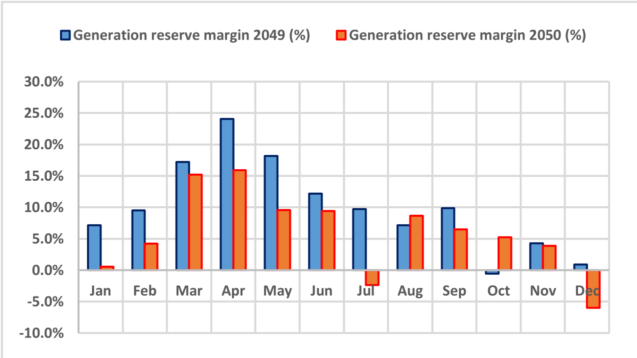

FIGURE 21. Comparison of generation reserve margin for years 2049 and 2050.

A third system reliability metric is capacity reserve margin. The capacity reserve margin is the firm capacity of the system on top of peak demand divided by peak demand. In this study, thermal generators are assumed to have firm capacity of 100%, electricity storage (BESS and PHP) 75% and hydro storage 100%. The firm capacity of VRE is estimated by EPM using a simplified approach which compares the capacity factor of VRE during the peak demand hour with the average capacity factor over a full year.[8]

Seasonal analysis of demand and VRE time-series indicate that over both low and average RE year, system capacity reserve margin is negative over all months (fig. 22). In addition seasonal correlation of VRE and capacity reserve margin is weak (fig. 23 and fig. 24). The firm capacity of both technologies is below 10% of rated capacity over July when system experiences the largest capacity shortfall. Over an average RE year, both wind and PV offer low firm capacity in November and December when again, system experiences shortage of firm capacity.

The analysis above suggests a possible need for year round back-up firm capacity (for example OCGT), which seem to be confirmed by the results of the LCP to be discussed later on. More detailed analysis of system reliability involving estimation of VRE effective load carrying capability (ELCC) is beyond the scope of this work but could provide valuable insights.

System inability to supply demand at all times has potential impacts on the wider economy. To account for this, the Turkey model includes a penalty of $2,000 per MWh of unserved

[8]Fig. 22 shows system firm capacity on monthly basis. It should be noted that the firm capacity constraint on EPM is based on a single annual value of firm capacity for each technology. Firm capacity of wind and PV on uncorrdinated charging scenarios has been estimated as 7.5% and 6% respectively for year 2049 and 7.4% and 4.5% for year 2050. In scenarios with coordinated charging the capacity factors for wind and PV has been estimated as 4.8 % and 16.1% respectively for year 2049 and 3.6% and 13.4% for year 2050.

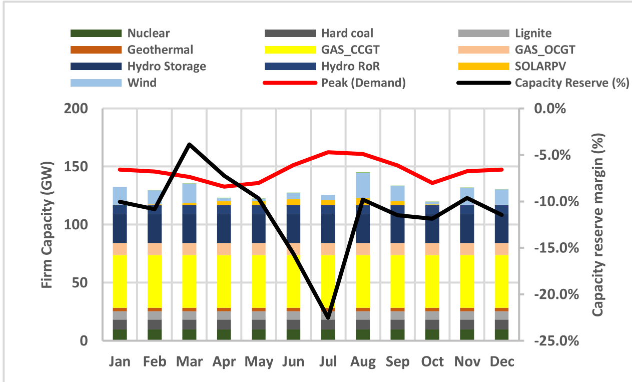

FIGURE 22. Firm capacity and capacity reserve margin over year 2050.

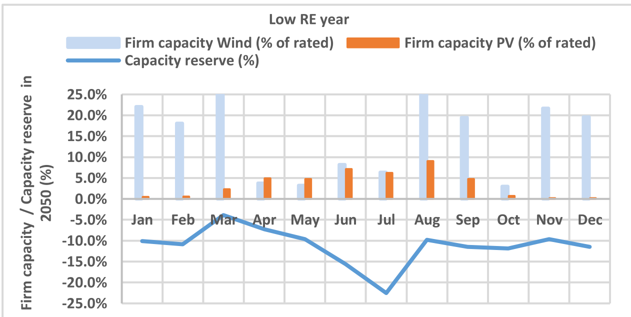

FIGURE 23. Comparison of system capacity reserve margin and firm capacity of VRE over a low RE year.

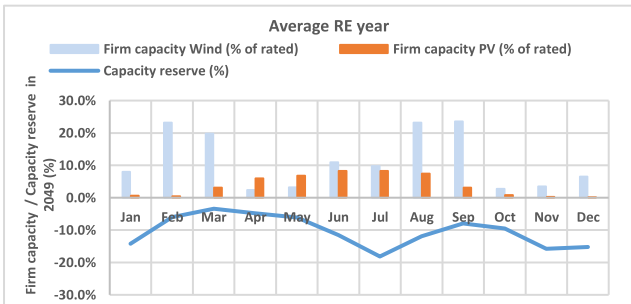

FIGURE 24. Comparison of system capacity reserve margin and firm capacity of VRE over an average RE year.

electricity demand. This is accounted for in the objective function of EPM and reported as part of system cost. Fig. 25 shows the seasonal operational costs of the system over an average RE year (2049). It can be seen that there are months where system costs due to loss of load exceed all other costs combined including fuel; this indicates that system operation in the incumbent plan is uneconomical from a societal prespective.

The next step in analysis involved the combined dispatch with LCP optimization to bridge the identified gaps in system adequacy. A comparison of total installed capacity between the Baseline plan and the enhanced plan (Scenario 2) is shown in fig. 26. Nearly 95GW of additional capacity is needed

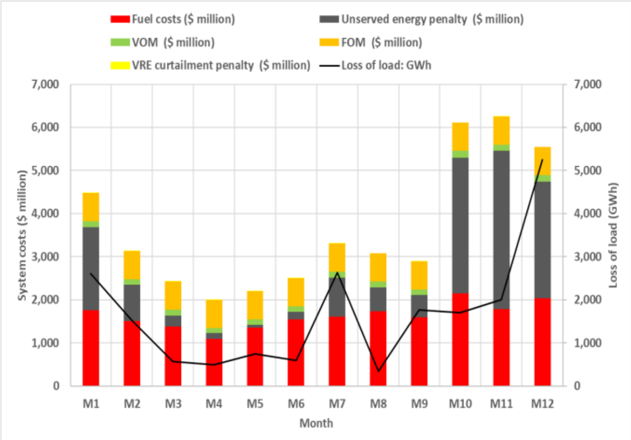

FIGURE 25. Breakdown of system operational costs over an average RE resource year.

to restore system generation reserve margin. The breakdown of additional capacity per technology is shown in table 14. The Baseline capacity mix needs to be supplemented by a total of 22GW of CCGT, 25GW of OCGT and 46GW of PV. This significant amount of capacity satisfies the system requirement of 8% capacity margin[9] and eliminates the loss of load enabling the system to supply demand at all times including years of low RE resource (see table 15).

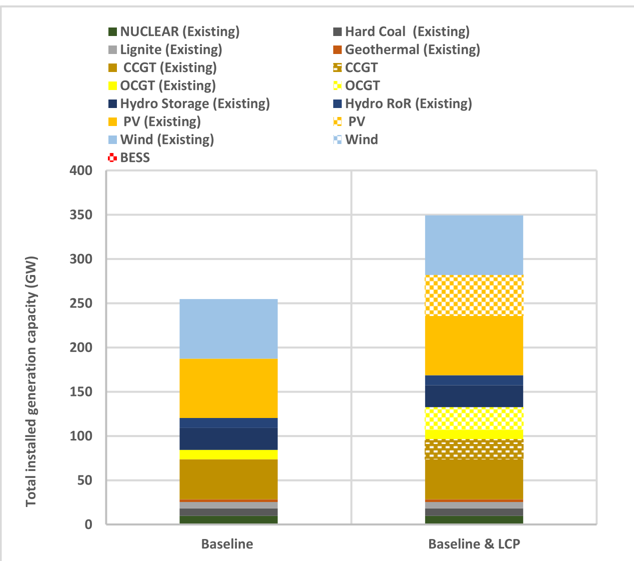

FIGURE 26. Comparison of capacity plans (Baseline vs Baseline & LCP). In the enhanced plan capacity is broken down as existing and new additions.

Table 15 shows a comparison of system operation between the Baseline and the updated plan. The net present value of costs of the updated plan is nearly one third compared to the Baseline even though the updated plan is heavy on new

[9]The capacity margin constraint is defined as an input on EPM. Assumption for system capacity margin of 8% was made after consultation with MENR.

TABLE 14. Capacity additions (MW) over baseline in Scenario 2.

	2049	2050	Total
BESS	0	0	0
PHP	0	0	0
CCGT	16,513	6,243	22,756
OCGT	25,614	0	25,614
Wind	0	0	0
PV	36,505	9,892	46,397

investments. This is because the economic impact of failing to meet demand (in Scenario 1) dominates system costs being nearly an order of magnitude larger than CAPEX costs in Scenario 2. CO_2 emissions in the draft plan are around 236 million tonnes in 2050. This translates into emissions intensity for the system at around 252gr of CO_2 per kWh.

After additions of around 46GW of PV capacity total installed capacity of wind and PV reaches 67.4GW and 113.5GW respectively by 2050. Increased PV generation increases VRE curtailment. Around 1.9% of PV and Wind generation (or around 7.4TWh) is curtailed in an average RE year. New PV combined with additional 48.3GW of gas fired capacity (CCGT/OCGT) greatly improves reliability metrics. More specifically, loss of load is eliminated, while generation reserve margin always stays above 40% (fig. 27). The optimal capacity plan (using EPM) is designed for a capacity reserve margin of 8%. As shown in fig. 28, the capacity reserve margin of the system is always above 8% reaching its minimum level (of 8%) in July and exceeding 14% all other times. Significant contribution on firm capacity is provided by OCGTs that are added in the optimal plan as peaking capacity operating at a capacity factor of 2% and providing backup capacity. New CCGTs, on the other hand, run at a capacity factor of 80%.

The second part of analysis focuses on estimation of the least-cost capacity mix to achieve decarbonization of the power sector. Total installed generation capacity in the Decarbonization scenario reaches 573GW of capacity i.e., nearly twice the capacity in the enhanced Baseline (refer to fig. 29). It should be noted that the two capacity plans are not directly comparable because total electricity demand in the Decarbonization scenario is also higher by 321TWh (nearly one third of demand) to meet the exogenous demand for green hydrogen. Comparing capacity needs, though, provides an indication of the additional power capacity required for cross sectoral decarbonization.

The capacity plan in the Decarbonization scenario (Scenario 3) is dominated by renewables accounting for 79% of generation capacity in 2050. More specifically, solar and wind account for 72% of total installed capacity and hydro around 6.5% with the remaining 0.5% being biofuels and geothermal. If nuclear and CCS are added, total non (or -low) emitting technologies account for 94.3% of total installed generation capacity.

TABLE 15. Comparison of system simulation results between scenarios 1 and 2.

		1) Government plan			2) Government plan & LCP		
		2049	2050	Total	2049	2050	Total
Supply and demand	Electricity demand (conventional and transport) (TWh)	930	956	1,886	930	956	1,886
	Total peak demand (GW)	157.6	162.3	N/A	157.6	162.3	N/A
	Generation (Including storage losses) (TWh)	922	936	1,859	930	956	1,886
	Unmet demand (TWh)	7.5	20.2	27.7	0.0	0.0	0.0
	Unmet demand (% of total demand)	0.8%	2.2%	N/A	0.0%	0.0%	N/A
	CO2 emissions (million tonnes)	213.1	236.6	449.8	187.3	206.2	393.5
System costs	NPV (for 2049 - 2050) ($million)	186,558			61,872		
	Total CAPEX ($million)	0	0	0	39,463	9,123	48,586
	Annualized CAPEX ($million)	0	0	0	2,968	3,637	6,605
	FOM ($ million)	7,851	7,851	15,703	9,155	9,409	18,564
	VOM ($ million)	1,627	1,725	3,352	1,523	1,624	3,147
	Fuel costs ($ million)	19,552	22,872	42,425	16,025	18,578	34,603
	Unserved energy penalty ($ million)	14,905	40,477	55,382	0	0	0
	VRE curtailment penalty ($ million)	40	9	49	447	410	857

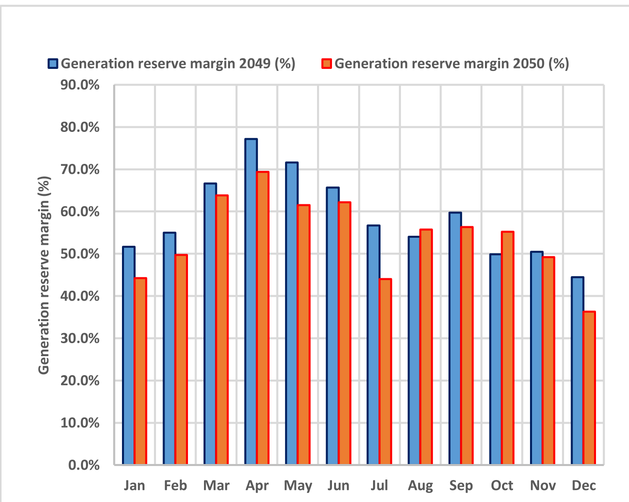

FIGURE 27. Updated generation reserve margin after capacity additions on the Baseline (Scenario 2).

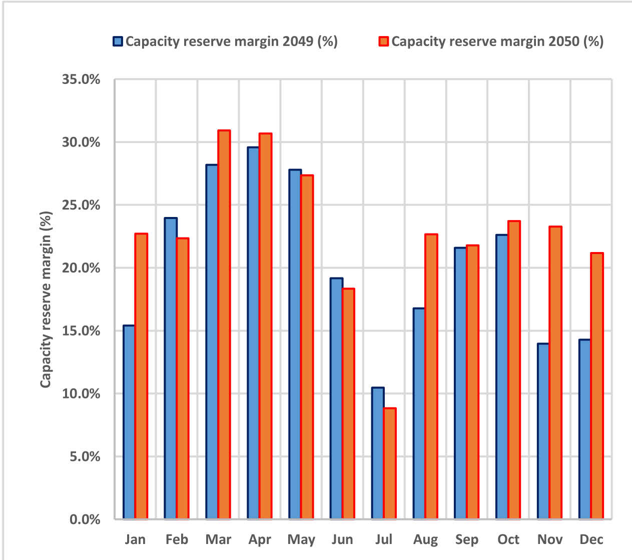

FIGURE 28. Updated capacity reserve margin after capacity additions on the Baseline (Scenario 2).

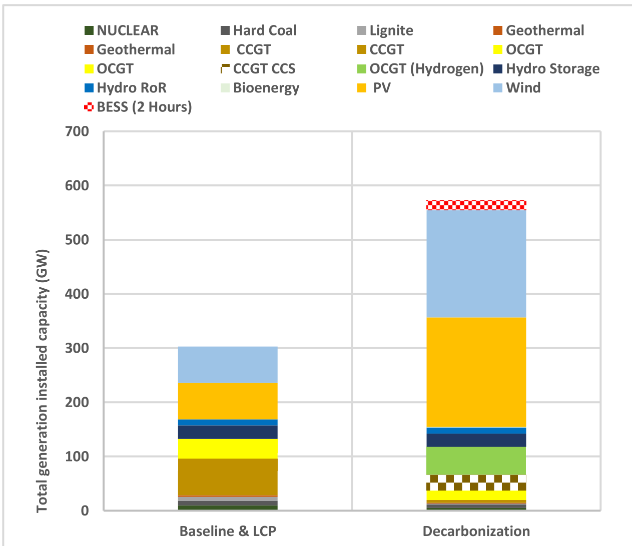

FIGURE 29. Comparison of capacity plans. (Enhanced baseline vs decarbonization.)

In the Decarbonization, scenario a significant amount of electrolyzer capacity and P2G plants is required for production of green hydrogen. Around 79GW of electrolyzers and 58GW of P2G plants are required to produce around 143TWh of SNG and 68TWh of pure hydrogen. From the above it can be concluded that P2G plants are operated at higher capacity factors (fig. 32). All 143TWh of SNG and 20TWh of green hydrogen are used in other sectors (mandatory production) while 48TWh of hydrogen are recirculated in the power sector for electricity production (optimized hydrogen production). Recirculation of SNG for power production is not economic based on results. It should be noted that while the external demands for green hydrogen and SNG are inputs on EPM, the electrolyzer capacity is optimized and thus it is an output of the model.

Demand response at $80/MWh is utilized by the system bringing a net economic benefit mostly related to CAPEX savings. As seen in fig. 30 and table 16, demand response

TABLE 16. Capacity additions (GW) and capacity savings (GW) among decarbonization scenarios.

	Scenario 3	Scenario 4	Scenario 4 (Capacity savings compared to scenario 3)	Scenario 5	Scenario 5 (Capacity savings compared to scenario 3)
BESS (2 Hours)	18	36	18	16	-2
OCGT	18	8	-10	4	-14
CCGT with CCS	29	30	1	31	3
Hydrogen OCGT	51	39	-12	40	-11
Wind	199	197	-1	183	-16
PV	202	194	-8	212	10
Total generation capacity	**516**	**504**	**-12**	**486**	**-30**
AE electrolyzer	89	79	-9	79	-9
P2G	58	60	2	63	5
Total electrolyzer capacity	**146**	**139**	**-7**	**143**	**-4**

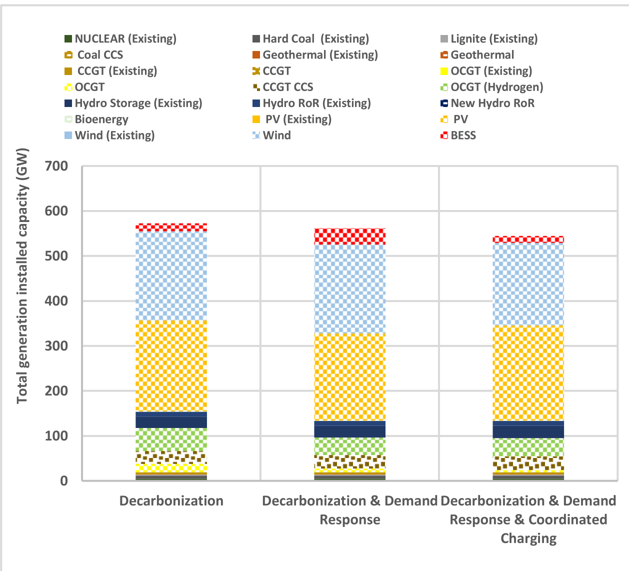

FIGURE 30. Comparison of capacity plans among decarbonization scenarios (Scenarios 3 to 5). Capacity is broken down per technology and per status (existing versus new). Existing capacity represents capacity which is currently online or is planned for commissioning in the medium term and expected to still be online by 2050. New capacity represents optimized additions to supply 2050 demand.

reduces system needs for generation capacity by around 12GW and electrolyzers/P2G by 7GW. Coordinated charging further reduces capacity needs by an additional 18GW of generation capacity. The combined capacity benefits of demand response and coordinated charging on the system is 30GW of generation capacity and 4 GW of electrolyzers/P2G. This is a significant impact on capacity needs, showcasing the important benefits of these actions to the system.

In the Decarbonization scenario, VRE energy production accounts for 70% of total generation (fig. 31). Total non - emitting generation together with low emitting CCGT with CCS generation account for more than 95% of total generation in the power sector. Fig. 32 shows an example of hourly dispatch for two days for scenario 4. Electrolyzers charge mostly during the daytime to take advantage of solar generation. During hours when combined non-synchronous generation (PV and wind) is very high, production of synchronous generators increases to strengthen system stability. Demand response is economic when demand is high and VRE production is low. In such a future state of the system dispatchable units will need to cycle frequently to match supply and demand. Even though around 18GW of BESS (2hrs of storage) are part of the decarbonization scenario its main role is supportive in the system providing operational and capacity reserve.

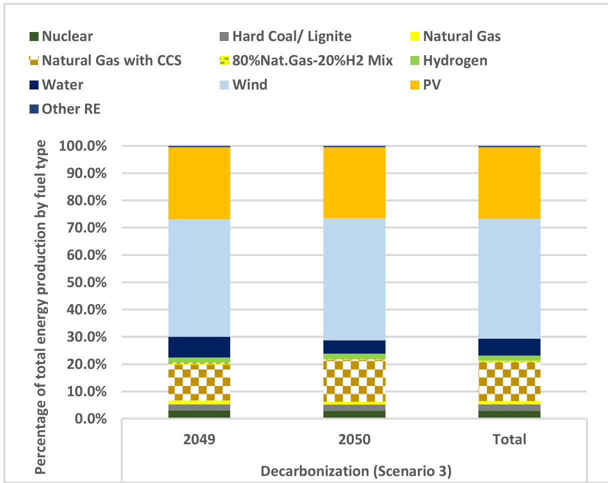

FIGURE 31. Energy mix by fuel for Decarbonization scenario per year.

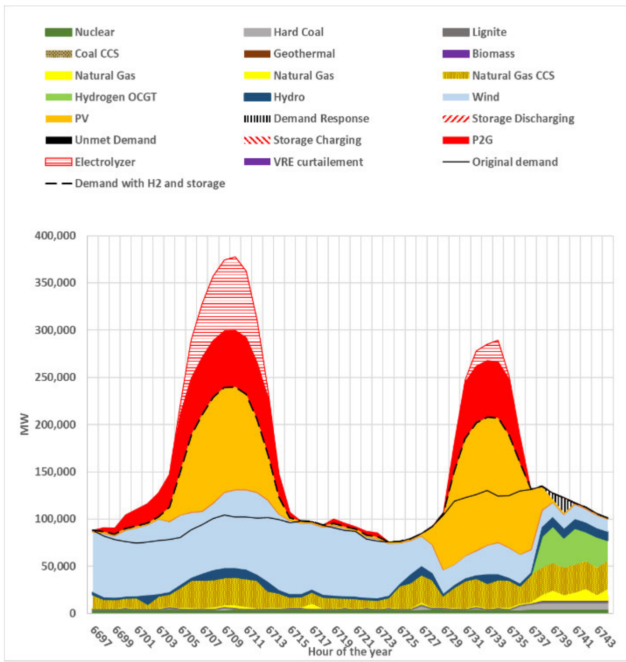

FIGURE 32. Example of two-day dispatch (Scenario 4: decarbonization & demand response.

Electrolyzers absorb most of VRE and there is little need for intra-day, time-shift of VRE. However, there is some need for long-term energy storage in the system which is provided through production of green hydrogen which in turn is converted back to electricity during the winter months. Most of the green hydrogen is used directly in hydrogen turbines but a small portion is mixed with natural gas to be used in conventional gas technologies. Electricity from green hydrogen accounts for around 2% of total electricity generation.

Production of green hydrogen does greatly increase peak demand. Based on results of this analysis, peak demand is expected to nearly double due to electrolyzer operation (see table 17). Apart from major ramifications of such a sharp increase in peak demand on the capacity plan itself, sharp peaks will also pose stress on the transmission and distribution (T&D) networks. T&D investments analysis was not part of this study.

TABLE 17. Demand and supply balances and CO2 emissions comparison across decarbonization scenarios.

	Decarbonization		Decarbonization and Demand Response		Decarbonization & Demand Response & Coordinated Charging	
	2049	2050	2049	2050	2049	2050
Electricity demand (TWh)	930	956	930	956	929	955
Additional demand for green hydrogen production (including SNG) (TWh)	321	331	302	314	306	310
Total electricity demand (TWh)	1,251	1,288	1,232	1,270	1,235	1,265
Peak demand (GW)	157.6	162.3	154.7	162.3	157.6	159.4
Peak demand accounting for electrolyzer operation (GW)	290.7	304.3	282.3	297.1	291.7	301.7
Total generation (TWh)	1,251	1,288	1,232	1,270	1,235	1,265
% of total generation for hydrogen production	34%	34%	26%	32%	33%	33%
Unmet demand (TWh)	0.0	0.0	0.0	0.0	0.0	0.0
CO2 emissions (million tonnes)	38.0	36.3	38.0	35.9	38.0	35.6
CO2 emissions reduction compared to Baseline scenario (million tonnes)	149	169.7	149	170.1	149	170.4

CO_2 emissions in the Decarbonation scenarios are only 21% of emissions of the Baseline scenario. More specifically, the CO_2 emissions cap of 38 million tonnes is achieved in 2049 but the constraint of 35 million tonnes of CO_2 is violated by 1.3 million tonnes in 2050, which is a year with low RE resource. This is because the system is reaching its limits on absorbing VRE. Further marginal decarbonization will come at high marginal system costs. Thus, it is cheaper for the system to bear some penalty (provided as input at \$300/ton) rather than incurring substantially higher cost to meet the CO_2 target.

Table 18 shows a breakdown of nominal system costs for the decarbonization scenarios. The nominal value of total annual system cost is the sum of annualized CAPEX, OPEX costs and all type of system penalties. In the Decarbonization scenario, annualized CAPEX accounts for 52% of total system costs in 2050 and is the largest of all cost elements, followed by FOM (22.5%) and fuel costs (17.2%). While demand response reduces generation capacity needs by around 12GW, any economic benefits from capacity deferrals are largely counterbalanced by the cost of DR and increased fuel costs so that the net economic benefit is small, only around 200 million USD per annum. However, when combined with coordinated charging the net economic benefit on the system is much larger (around 1.5 billion USD per year)

TABLE 18. Comparison of system costs across decarbonization scenarios.

	Decarbonization		Decarbonization and Demand Response		Decarbonization & Demand Response & Coordinated Charging	
	2049	2050	2049	2050	2049	2050
Present value of costs (for 2049 and 2050) (\$million)	137,307		137,069		134,181	
Total CAPEX (\$million)	448,840	37,217	444,764	38,083	429,291	40,174
Annualized CAPEX (\$million)	35,307	38,265	35,081	38,087	33,705	36,839
FOM (\$ million)	15,316	16,337	15,242	16,272	14,665	15,753
VOM (\$ million)	5,022	5,186	4,797	4,975	4,859	4,948
Fuel costs (\$ million)	11,666	12,969	11,891	13,271	12,186	13,765
Unserved energy penalty (\$ million)	39	42	18	13	0	0
VRE curtailment penalty (\$ million)	485	574	501	574	536	573
Cost of CO2 leak (\$ million)	0	383	0	256	0	187
Cost of Demand Response (\$ million)	0	0	126	130	124	127
Total annual costs (\$ million)	67,835	73,756	67,656	73,578	66,075	72,192

Additional analysis to fully understand the Decarbonization included running two sensitivities around it. The first sensitivity included optimistic electrolyzer CAPEX (Scenario 3a). The second sensitivity assumed no existing coal by 2050 (Scenario 3b).

Adoption of optimistic cost for hydrogen production has a small effect on electrolyzer capacity (see table 19) and recirculation of green hydrogen in the power system.

In the ''no coal'' sensitivity, there seem to be significant differences on capacity additions. The existing coal capacity of nearly 9GW is replaced by 9GW of CCGT. Total OCGT additions amount 56GW, which is comparable to OCGT additions in the Decarbonization scenario. However, it is interesting to note that hydrogen recirculation in the power system is no longer cost effective as natural gas is more competitive in this scenario.

VII. CONCLUDING REMARKS

The present modeling exercise explores some of the emerging challenges that many countries are facing today including Turkey, around their decarbonization goals. As a starting point for the analysis, we used a capacity plan prepared by the Ministry of Energy and Natural Resources of Turkey which

TABLE 19. Comparison of new capacity additions across decarbonization and sensitivities.

	Decarbonization	Decarbonization & Optimistic costs for electrolyzers	Decarbonization & No coal
BESS (2 Hours)	18	18	29
CCGT	0	0	9
OCGT	0	9	56
CCGT with CCS	29	30	27
Hydrogen OCGT	51	50	0
Wind	199	193	201
PV	202	208	158
Other RE	1	1	1
AE electrolyzer	89	92	23
P2G plant	58	59	73

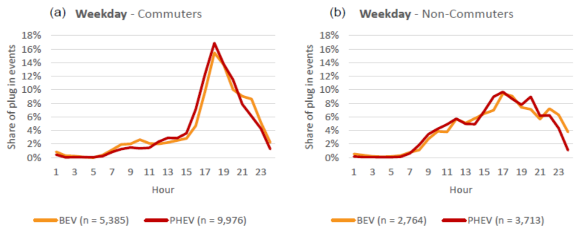

FIGURE 33. Average plug-in start time profiles at home for weekday charge events for (a) commuters and (b) non-commuters, from the interim Electric Nation dataset of the United Kingdom. BEV stands for battery electric vehicles, PHEV for plug-in electric vehicles. 'n' is the number of charge events in the sample (Source: [42]).

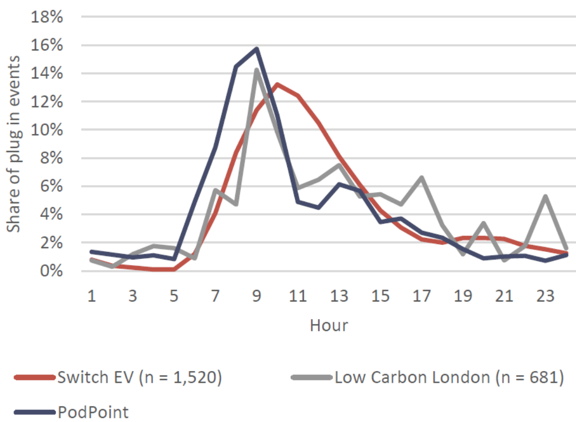

FIGURE 34. Average plug-in start time profiles at workplace charge points, from various data sources in the United Kingdom 'n' is the number of charge events in the sample (Source: [42]).

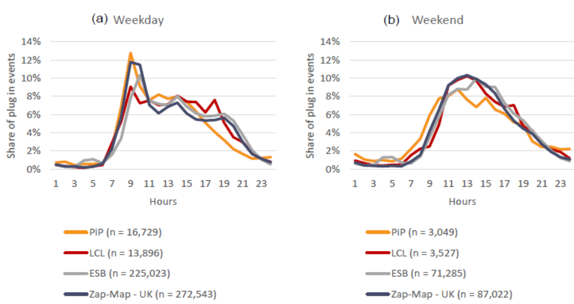

FIGURE 35. Average (a) weekday and (b) weekday plug-in start time profiles from various data sources in the United Kingdom. 'n' is the number of charge events in the sample. PiP stands for Plugged-in Places, LCL for Low Carbon London and ESB for ESB e-cars(Source: [42]).

has a large share of solar and wind to meet 33% of its baseline electricity requirement in 2050. Our analysis using the World

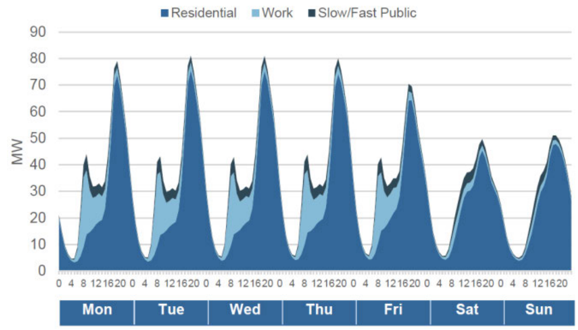

FIGURE 36. Weekly average demand profile, averaged over full year for a stock of 180,00EVs in Great Britain based on data from 2018 (Source: [43]).

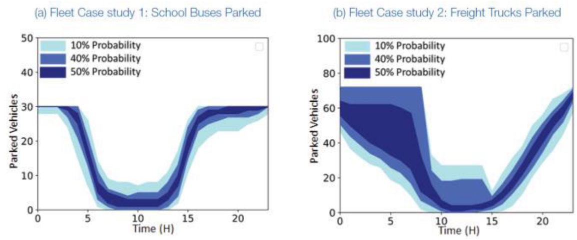

FIGURE 37. Number of vehicles likely to be parked at the fleet depot throughout the day for two types of fleet vehicles: school buses and freight trucks. Freight vehicles tend to start later than school buses and return over a longer period of time as they complete their trips (Source: [52]).

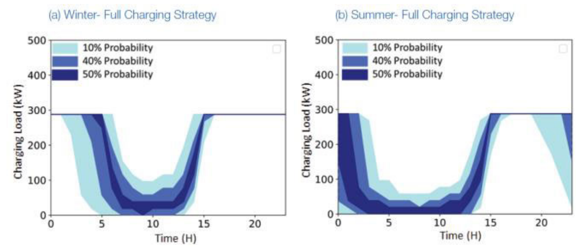

FIGURE 38. (a) 1,000 charging scenarios for a fleet of 30 school buses in the winter. The charging requirement for the fleet is facilitated by 15 chargers rated at 19.2kW each. School buses in most scenarios start trips between 5:00-7:00am, and return to the depot between 3:00-6:00pm, with an average dwell time between 13-16 hours. (b) During summer charging time is reduced to 5-6 hours from 8-9 hours in winter (Source: [52]).

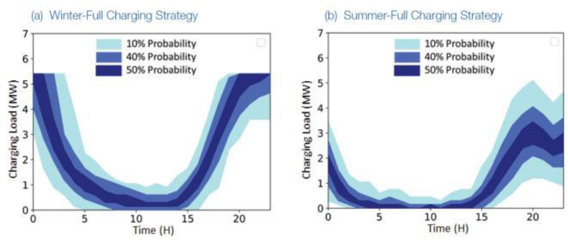

FIGURE 39. Freight fleet's aggregate charging load during winter and summer for a fleet of 72 freight trucks. The fleet depot is assumed to have 36 chargers rated at 150kW each. Charging efficiency is similarly lower during winter months. Freight trucks return at the depot from 4pm to midnight (Source: [52]).

Bank Electricity Planning Model (EPM) revealed the need for great attention needs to be paid to assess the performance of such a plan taking into consideration significant seasonal and interannual variability of solar and wind. Indeed, our findings included a high probability of loss of load during several months of the year arising from such variability. As the next step, we developed a mitigation strategy including re-optimization of the capacity mix that can restore system adequacy at nominal cost. The second set of challenges for Turkey is its aspiration to electrify its transport and also produce green hydrogen to decarbonize other sectors. As most of the existing planning tools cannot fully address some of the modeling requirements like endogenous treatment of green hydrogen or coordinated charging of EVs – we extended EPM to model these aspects. The additional load arising from EV and green hydrogen may place a great burden in terms of additional investments needed that further emphasizes the need to optimize investment and production decisions. These include the significant relief that may be elicited from the coordinated charging of EVs, using part of the green hydrogen as a fuel to meet peaking requirements when the VRE level is low, and introducing large-scale demand response programs. There is a viable pathway for Turkey to decarbonize its economy. However, it requires great care in analyzing the options at hand not to expose the system to a risk of running out of power or an exorbitant level of investment in a backup capacity.

APPENDIX

See Figs. 33–39.

ACKNOWLEDGMENT

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