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Analyzing Electric Vehicle Load Impact on Power Systems: Modeling Analysis and a Case Study for Maldives

ADAM SUSKI, TOM REMY, DEBABRATA CHATTOPADHYAY, CHONG SUK SONG, IVAN JAQUES, TAREK KESKES, AND YANCHAO LI
The World Bank, Washington, DC 20433, USA

Corresponding author: Adam Suski (asuski@worldbank.org)

ABSTRACT Electric vehicles (EVs) can have massive benefits in energy sector especially for a small island country like the Maldives that imports oil with high transportation costs while power could have been generated from abundantly available local renewable resources. However, EV charging may also impose significant investment requirement for the power system that needs to be analyzed carefully including the capacity of the existing distribution network system, investments needed in solar PV together with battery storage and additional diesel capacity to meet the incremental demand from EVs. We explore an EV adoption scenario for Maldives for 2030 with 30% of all vehicles including two-wheelers that dominate the transport on the island under two different charging regimes: uncoordinated and optimized coordinated mode. The latter is achieved through a system wide optimization using a modified version of the World Bank Electricity Planning Model (EPM) that optimizes charging load subject to a range of constraints on allowable timing for different categories of vehicles. If charging from the fleet is uncoordinated, a relatively small increase in energy requirement of 3.1% due to EV may lead to a 26.1% increase in generation capacity requirement and hence 15.7% additional investment. While the optimized charging regime helps to drastically cut down on generation capacity requirements to just 1.8% increase and also considerably eases feeder loading, it may also lead to *higher* emissions as more EV load during off-peak hours lead to an increase in diesel-based generation. We have therefore explored an additional scenario wherein the annual emissions from the power sector are constrained to the baseline (''No EV'') scenario. The analysis shows the importance of focused modeling analysis to understand the ramifications of EV load impact on the power system including significant increase in generation capacity and potential increase in power sector emissions in a fossil-fuel dominated system.

INDEX TERMS Electric vehicles, power system optimization, least-cost planning, distribution network.

I. INTRODUCTION

A. CONTEXT

Electric vehicles (EVs) together with cleaner forms of power generation technologies present a formidable option to decarbonize the transport sector. Countries, institutions, companies and international development communities have been stepping up, introducing electric mobility (e-mobility) targets, strategies and funds, fostering innovation and deployment [1], [2]. In many advanced economies, e-mobility markets are already well-established and EVs started to constitute a substantial share of annual vehicles sales [3]. Nevertheless, transport decarbonization still remains a particularly significant issue in many developing countries with fossil fuel dominated power systems, crowded and polluted cities with heavy traffic, where unsustainable transport poses a threat for urban communities [4].

Small Island Developing States (SIDS) like the Maldives, which generates almost all its electricity from expensive imported diesel fuels, presents a good example of potential challenges and the need for aligning transportation with power system targets. Nearly half of the population lives in the crowded capital of Malé, covering an area of less than 10 km^2. Maldives, located in the equatorial Indian

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Ocean, has an abundance of available solar energy to generate power that can charge a good share of more than 80,000 currently unelectrified two-wheelers [5]. Nevertheless, economic and land constraints are slowing down the uptake of residential and utility-scale renewable energy installations [6], consequently leaving the country nearly entirely dependent on imported fossil fuels.

There are a few studies that examined the nature and magnitude of the impacts of EV deployment on power systems. For example, De Quevedo [7], Shortt and O'Malley [8], Mousavi Agah and Abbasi [9] and Pieltain Fernández [10] review and model impacts of EV charging on distribution, transmission and generation in the operational and planning context. However, the literature on quantifying the current or projected impacts in the existing EV markets is still relatively limited. The investment requirement to upgrade the grid, additional generation capacity requirements, increase in operational costs and changes in emissions profile, are important metrics to understand the full array of impacts. Some of these assessments are available mostly for developed countries where EVs have been introduced. EV impact assessment is limited for the developing world though even for cases like India that has announced its intent to do rapid electrification of its transport sector. Although the estimates for the developed countries cannot directly be applied for the developing counterparts given the substantially different nature of the physical systems, they still constitute a set of useful indicators of the nature and orders of increase in cost, capacity and emissions.. This information can be of value to decision makers, utilities and regulators in the emerging EV markets, especially in developing countries with typically more resource constrained power systems.

Furthermore, the modelling literature on power system planning for developing countries to assess EV impact is practically non-existent. This gives an incomplete overview of the technical, economic and environmental impacts of EV integration in power systems characterized by low flexibility, excessive level of backouts and failures, poor power quality or high share of fossil fuel generation. Additionally, the charging behavior of the EV owners in developing countries and the resultant aggregated load can vary significantly from the one observed in developed EV markets due to different demographics [11], climate [12], the share of the transportation modes [13] or availability of charging infrastructure [14]. Consequently, rapid EV deployment in developing countries, similar to the one observed in China [2], might result in impacts considerably different from those reported for developed countries. There may, for instance, be a significantly higher need to boost peaking capacity in the developing world with sharper peak demand growth compounded by demand from EV that may coincide with system peak.

These considerations provided the motivation for detailed long-term planning analysis. This forms part of a wider EV Flagship study undertaken by the World Bank. We have used a capacity expansion and dispatch model to explore the technical and economic viability of converting 30% of all vehicle modes to EVs by 2030. A sharp increase in peak demand and hence peaking generation and network investments are some of the fundamental power system challenges that are addressed as part of our technical analysis. This work underlines the importance of long-term modelling in achieving decarbonization targets. The rest of this paper is organized as follows:

- First, it provides background information on the Maldives power sector. Subsequently, it presents a comprehensive review of the international experience regarding EV impacts on the power system, including relevant case studies and modelling approaches. The review focuses on the quantification of reinforcement costs and capacity additions in the country-specific case studies.
- Second, it proposes a methodology to incorporate EV fleet charging load in the long-term electricity planning framework based on already existing and well-established planning models. It includes a detailed description of mathematical formulations, together with a comprehensive explanation of EV load assumptions and projections. We have also enhanced a standard planning model to consider optimization of EV load and further simulated a carbon-neutral EV load addition scenario.
- Third, it presents a comprehensive techno-economic case study to assess the impacts of EV fleet introduction on the power system of Maldives, with a detailed representation of the distribution system and two distinct charging strategies. Results of this study might be extrapolated to other SIDS countries as well as urban/peri-urban distribution areas with fossil fuel dominated power systems and limited land availability.

B. BACKGROUND INFORMATION ON MALDIVES

The Republic of Maldives is among the smallest countries in the world. The total population of nearly 550,000 people lives on 194 islands stretched out along 800 km in the central part of the Indian Ocean including around 250,000 in the capital of Malé. Tourism has become the main contributor to the country's annual gross domestic product (GDP) and allowed its graduation from a low-income country to upper-middle-income country status in 2011 [15]. However, Maldives is exposed to a high dependency on fossil fuel imports. The total fuel import in monetary terms amounted to 465 million USD in 2019, which was corresponding to 20% of the whole import and 8.7 % of the country's GDP.

The power system in the Maldives is composed of independent isolated island-based grid systems, with each island having its own powerhouse and distribution facility. Due to this, the power systems are reliant on imported diesel generation to meet almost all their power needs. In 2018, the total installed capacity was 335.5MW, where diesel generators accounted for 319 MW, while renewable energy units in the form of solar PV for only 16.5 MW. In total, 775 GWh was generated in 2018, with a 97% share from diesel generation.

There has been significant emphasis on cleaner forms of generation in future, especially solar PV, as noted in the Energy Policy and Strategy 2016 [16] and the Strategic Action Plan (SAP) 2019–2023 [17]. The most significant goals from the perspective of the power sector include a 4% share of renewable energy in the energy mix, reducing diesel consumption in the electricity generation sector by 40 million litres and scaling up energy storage capacities to 30 MWh. The Government of Maldives (GoM) aims at scaling up the initial targets and considers having a daytime peak met by solar PV with a 70% share by 2030 [18]. The commitment towards GoM's clean energy has recently been reinforced with the President of Maldives committing to net zero emissions as early as 2030 with international aid.

Apart from the power sector, transportation is another contributor to fossil-fuels dependency and greenhouse gas emissions. If the Maldives is able to transition towards a combination of sustainable power and transport systems that are based on cleaner forms of electricity generation, it would not only reduce the country's reliance on fuel imports but significantly reduce air pollution in the capital Malé, and boost the tourism industry by building a more positive image of the country [19]. EVs are expected to be the core solution towards the widespread transport decarbonization in SIDS. With the need for flexibility in the power system to deploy more renewables sources of electricity and high fuels costs, implementation of electrified passenger and public transportation systems may bring significant economic and environmental benefits for these nations by providing the required storage and grid service solutions when an appropriate EV deployment strategy is being considered [20].

II. LITERATURE REVIEW

A. EV IMPACTS AND INTERNATIONAL EXPERIENCE

Sustainable e-mobility is globally considered the most promising option to decarbonize the transportation sector and an important step towards achieving climate targets. However, quickly rising shares of EVs in sales and total stocks may pose significant technological and operational challenges for the generation, transmission, and distribution segments of the power systems. The aspects of potential techno-economic impacts of charging load have been widely studied over recent years.

The distribution part of the power system is the most prone to experience the stresses and negative impacts of EV deployment. At the local low-voltage level, a clustering effect might occur, causing spatial concentration of vehicles and consequently congregating the plug-in events [21]. Without smart charging strategies in place, allowing to shift the load towards a more favorable time, residential home charging is likely to happen right after returning from work, causing already existing evening consumption peak to amplify. In turn, distribution transformers and feeders might become overloaded, causing losses, failures, and shortening asset life [22]. Furthermore, uncontrolled EV charging can lead to power quality issues, including voltage deviations or harmonic distortions [23]. In order to accommodate the growing charging load and avoid serious reliability issues, electric utilities might be forced to make significant upgrades to the distribution system infrastructure. Boston Consulting Group (BCG) analysis [24] estimated that with uncoordinated charging and 15% penetration rate, required distribution investments through 2030 may reach up to 5,380 USD per EV in the US market.

In the remainder of this section, we present a summary of the literature that covers distribution system impacts (Table 1), followed by impact on demand/generation/emission (Table 2) and the modeling techniques used to capture EV impacts (Table 3).

Table 1 reviews relevant studies presenting international assessments of distribution system impacts and the consequent reinforcement costs. The review indicates that with uncoordinated charging, EV deployment will result in substantial reinforcement costs driven by the required replacements of transformers and cables.

Changes in the daily load due to the increasing number of EVs would also impact upstream transmission and should be considered as part of grid operation and expansion planning. While at the distribution level, the clustering effects within the same section of the grid pose a substantial challenge to the system operator, the impact on the high-voltage transmission grid is generally less severe. The BCG analysis assessed required transmission infrastructure reinforcements through 2030 to reach 420 USD per EV, which is just below 8% of the distribution sector cost impact. Nevertheless, at deeper EV penetration levels, or in systems with already congested transmission lines, uncoordinated charging can lead to high loading levels [25], more severe congestions and consequently increase wholesale electricity prices [26]. Furthermore, incorporating the EV load in the transmission expansion planning can result in additional investments or upgrade requirements to assure reliability and prevent load shedding or system failures in the future [27].

Charging of the EV fleet will have a direct impact on the dispatch of the generation units, power system emissions, operation costs and, in the long term, capacity expansion decisions. As the preceding discussions alluded to, without appropriate load shifting incentives, residential charging load is likely to be allocated to evening hours with high demand levels, subsequently being met with peak power plants. In most systems, peaking capacities comprise gas turbines or gas engines fueled with natural gas or liquid fuels such as heavy fuel oil, characterized by high variable costs. A sharper peak, especially in a small system, therefore not only calls for adding disproportionately more capacity but also increases operational expenses and emissions in the power sector. Since the charging load in the Maldives may occur during the evening peak that may be typically highly uncertain and variable, it may also call for a new capacity that is highly flexible to ensure security and adequacy of the grid. Table 2 presents the relevant studies evaluating the short and long-term impact of EV charging load on the

TABLE 1. **EV impact on distribution system: Summary of international studies.**

Country/region	Assumptions and findings
United States [24]	15% EV penetration in 2030. 5,800 USD of distribution investments per EV in the nonoptimized charging scenario
France [33]	Without smart charging total, low-voltage distribution grid reinforcement per million EV was estimated as 200 million EUR for charging in single houses, 650 million EUR for multiple charging in multi-dwelling or business buildings and 240 million EUR for public charging spots in the streets
United Kingdom [34]	Electric cars and vans achieving a 60% share of new vehicles by 2040, translated into a total of 22 million EVs by 2035, increase distribution network reinforcement costs by 40.7 billion GBP
Norway [35]	2.4 GW increase in load during peak hours due to EV charging would require 1.5 billion EUR to reinforce grid until 2040, with the third of that used to replace older elements.
Auckland, New Zealand [36]	Converting 15 bus depots to a fully electric fleet would require up to 32 million NZD investments in the local electricity grid
European Union [37]	150 TWh of incremental EV charging demand by 2030 increases overall reinforcements investments in distribution grid by nearly 180 billion EUR
Denmark [38]	100% penetration in the local distribution grid, corresponding to 127 EV, would require investments of 52,000 EUR for transformer and cables.
Sacramento, California [39]	240,000 electric cars by 2030 (together with other assumptions regarding solar PV, energy efficiency and demand response) could cause voltage violations in 26% of substations and the need for replacement of 17% of transformers at an approximate cost of 89 million USD.
New Zealand [40]	At a 10% penetration level with 2.4 kW home charging, the distribution grid would require 22 million USD of reinforcements, rising to 154 million USD with 40% penetration depth and the same charging scheme.
General [10]	For a scenario with 60% of total vehicles being PEV, DSO investment costs can increase up to 15% of the total actual distribution network
Ireland [41]	At 20% EV penetration, necessary grid upgrades are estimated at the level of 350 million EUR. Out of that, 150 million EUR account for urban areas, while 127 million EUR for rural areas. Smart meters for home chargers require an additional 68 million EUR.
Switzerland [42]	With over 130,000 EV charging points and 1,350 MW of chargers' capacity in 2035, grid reinforcement costs would amount to 129 million CHF. 44% of the transformers would require upgrades. Rural areas would require the highest specific reinforcement costs per kW of charging power.
Madrid, Spain [43]	Electrification of 500 vehicles among 25 postal hubs, assuming fast 22 kW peak time charging, would result in 121,624 EUR of distribution network reinforcements and 7,117 EUR of power losses costs.
Kartal region, Turkey [44]	To accommodate load with 9,636 EVs by 2030, the Kartal region would need to install three distribution transformers, increasing required grid investments by nearly 28,000 USD.
United Kingdom [45]	Two low-voltage feeders have been analyzed. The first one, serving 149 customers, would require reinforcement investments of 5,600 GBP at 50% EV penetration (reaching in 2034). The second one, serving 106 customers, would require 4,800 GBP of reinforcement investments at 70% EV penetration (in 2038).
New Zealand [46]	With 50% of heating and transport electrification by 2030 and 100% by 2050, distribution networks reinforcement costs amount to 1.9 billion USD in 2030 and 4.9 billion USD in 2050.

generation fleet. These studies reveal flexible peaker plants (gas turbines and engines) to be required in the capacity mix with the uncoordinated charging in place, subsequently increasing the system's emissions and total costs.

While reinforcing the grid and expanding the asset's capacity is one way to cope with growing charging demand, smart charging and battery swapping strategies may be potentially good alternatives to partially mitigate the negative impacts. Smart charging allows controlling a specific part of the EV charging load through technological and incentive programs introduced by electric utilities. The simplest and currently most popular smart charging approach is the introduction of time-of-use (TOU) tariffs, incentivizing EV owners to plug in their vehicles during times of lower electricity prices. TOU schemes have been proven to be an effective way of peak shaving and mitigating major EV-related capacity investments in distribution, transmission and generation segments [28], [29]. Battery swapping to provide significant flexibility around when depleted batteries can be recharged enhances the prospect of utilizing cheaper renewables and/or surplus capacity to avoid an addition to peaking capacity, albeit at additional expenses for spare battery capacity and infrastructure that is needed for swapping. Furthermore, vehicle-grid integration (VGI) allow EV owners and system operators to control, modulate and shift charging load. VGI schemes range from turning on and off the charging power through unidirectional charging load control (V1G) to bidirectional vehicle-to-everything (V2X) technologies. VGI technologies, apart from mitigating the most severe impacts of EVs to the power systems, may bring a series of additional benefits, including frequency control, auxiliary services, short-term storage services, and supporting the integration of variable renewable energy (VRE) [29]. As the full array of technologies around smart charging, battery

TABLE 2. EV impact on demand, generation and emissions: Summary of international studies.

Country/region	Assumptions	Power generation impacts
Chongqing, China [47]	2 million electric cars and unmanaged charging strategy	Evening peak increases by 6.7%, causing operating costs of the power system (including fuel, O&M, reserves, curtailment and trade) to increase by 6.5 billion USD (7.8%).
China [48]	174 million EVs on the roads in the moderate scenario and 349 million EV in the aggressive scenario by 2050 + 70% reduction in power sector emissions by 2050	10%, 13% and 6% increase in gas, storage and solar capacity respectively between moderate and aggressive scenarios. 55.5 billion USD (4.4%) increase in annual total power system costs by 2050. Even in the uncontrolled charging scenario, the average CO2 emissions of the power system in 2050 decrease from 90.16 kg/MWh in the moderate scenario to 87.37 kg/MWh
United Kingdom [49]	14.6 million EVs in 2040, translating to the demand of 34.1 TWh, increasing daily peak demand of 9.4 GW	Total capacity requirements in 2050 are 9.2 GW (5%) greater than in the base case without EV demand driven by flexible capacities of gas turbines, battery storages or transmission capacities.
Texas, Finland, Germany, Ireland and Sweden [8]	Evaluation of impacts generation portfolio impacts with penetration between 0-5%.	Net-costs of the power system supplying the EV charging load range between 200-400 EUR/year per vehicle for 0.5% penetration, but the costs vary significantly depending on RE penetration or CO2 costs. Without CO2 costs, the coal and gas turbines capacity increases with deeper levels of integration.
India [50]	367 million electric-two wheelers and 89 million electric passenger cars by 2030.	The total peak EV charging load exceeds 30GW, which is about 6% of the total peak load by 2030 (480 GW). The demand might be fully met with already planned capacity expansion
Barbados [51]	26,600 EVs on the road by 2030	In case of uncontrolled charging, 25% of extra production costs are added to the power system—over 30% increase in the yearly average marginal cost of electricity.
New York, US [52]	10% penetration of passenger cars, corresponding to 900,000 vehicles.	System costs increase by 0.15 billion USD per year (3.7%) with a capacity expansion scenario in comparison to a scenario without EVs. There is an increased investment in gas units.
Chile [27]	150,000 electric passenger cars, 28,000 taxis and 360 electric buses.	Compared to a scenario without EV deployment, generation investments increase by 18 million USD (2.8%), while operational costs by 18 million USD (1%).
Germany [53]	6 million EVs in 2030 with various CO2 prices scenarios	With the uncoordinated charging, the production from lignite, hard coal and natural gas plants are higher for all CO2 price scenarios in comparison to the case with no EVs. With a CO2 price of 20 EUR/t, system operating costs increase by 0.2 billion EUR (2%) and emissions increase by 5 Mt (3.5%)
Alberta, Canada [54]	5% EVs penetration in 2020 raising go 20% in 2031 corresponding to 2500 GWh of additional demand	The EV charging demand is met with natural gas and imports. With uncoordinated charging, the contribution of the electricity sector to power system emissions decreases from 32.6% to 30.6%. 350 MW of new generation capacity is needed in 2031.

swapping and VGI unfold, it may be possible to use the flexibility these entail to minimize the impact of EV load on the power system. Moreover, the introduction of an appropriate energy management system linked with distributed energy resources can further reduce charging costs and maximize benefits from the exchange with the grid [30]. These benefits can be fully unlocked only if the charging infrastructure and energy management systems are carefully designed and operated [31], [32]. The availability of these technologies in a developing country power system like Maldives would however take significant time, effort and investments. A full cost-benefit analysis of such flexibility also requires further exploration and methodology development – an issue that is not covered in the scope of the current paper.

B. OVERVIEW OF EV MODELING LITERATURE

Recent studies show that the impact of large-scale EVs deployment on absolute electricity demand might be limited to an increase reaching up to 10% of the total consumption [55], which is likely to be accommodated by the power system without causing undue stress. Over the years, numerous researchers incorporated EV load into the dispatch and capacity expansion models, determining impact on the operation costs, investments decisions, and environmental factors under various charging approaches. In 2007, Oak Ridge Competitive Electricity Dispatch model was used to evaluate the charging impact of Plug-in Hybrid Electric Vehicles (PHEVs) on the Virginia-Carolinas electricity grid, showing that peak charging leads to intensified use of combustion turbines and combined cycle plants [56]. In [57], the National energy modelling system (NEMS), used by US Energy Information Administration (EIA), was adjusted to investigate the impact of four different charging strategies on the power capacity expansions. A long-term capacity expansion model based on the mixed-integer linear programming (MILP) approach is used in [58] to evaluate the value of EVs flexibility. Two inflexible charging strategies were proposed, supported with vehicle-to-grid (V2G) services, assessed for the case study of the UK power system. MILP model was also deployed in [27] to analyze the impact of different EV charging strategies on the power system expansion in Chile, considering co-optimization of transmission and generation investments. In [59], the MILP-based optimization model was expanded to include day-ahead and real-time markets stages in the decision process, creating the multi-stage stochastic program used to analyze the impact

TABLE 3. Review of the EV modelling studies.

Ref.	Year	Model/methodology/solution method	Modelling horizon	Case study	Charging schemes
[55]	2019	Integration of EVs is evaluated with Electricity Systems Investment model (ELIN) and an Electricity System Dispatch model (EPOD)	Up to 2050	Sweden, Norway, Denmark and Germany	Optimization and optimization with V2G
[56]	2007	ORCED (Oak Ridge Competitive Electricity Dispatch)	Up to 2020	Southeast United States	Uncoordinated charging
[57]	2008	National Energy Model System (NEMS)	Up to 2030	United States energy markets	Uniform, charging; home-based charging; off-peak charging, V2G charging
[58]	2016	MILP economic dispatch and unit commitment model	Single year optimization	United Kingdom system	Inflexible EV operation and smart charging of part of the fleet
[27]	2020	MILP capacity expansion model	Up to 2030	Chilean power system	Uncoordinated and coordinated charging
[59]	2019	Three-stage stochastic program with Benders decomposition	Up to 2050	The power system of Lanzarote-Fuerteventura in Spain	Uncoordinated and coordinated charging
[52]	2014	MILP capacity expansion model with hourly unit commitment and dispatch	Single year, 20 representative days	NYISO system	Uncoordinated and coordinated charging with hourly and 15-min resolution
[60]	2015	Monte-Carlo-Based portfolio modeling tool coupled with economic dispatch model	Single year optimization	The Australian National Electricity Market (NEM)	Residential charging unmanaged, universal charging unmanaged and universal charging managed
[8]	2014	Integrated capacity expansion algorithm with unit commitment model	Single year optimization	Power systems of Texas, Sweden, Finland, Germany, and Ireland	Controlled and uncontrolled charging
[61]	2012	Brazilian MESSAGE model	Up to 2030	Brazil energy system	Uncontrolled charging
[62]	2020	Iterative short- and long-term capacity expansion algorithm	6-year horizon	Generic microgrid case	Optimized operation of electric vehicle charging station
[7]	2019	MILP with scenario generation by k-means methodology	15 years in 3-year stages	Generic case study	Uncoordinated charging
[63]	2020	Adaptive robust optimization problem, solved with column-and-constraint generation algorithm	Single year optimization	69-bus test distribution system	Optimized charging
[64]	2018	MILP model with the robust multistage joint expansion planning and uncertainties in load	15 years in 5-year stages	18-node test distribution system	Uncoordinated charging with uncertain EV load
[65]	2020	Particle swarm optimization and tabu search hybrid approach	24-hour period	PG&E 69-bus test system	Optimized charging
[66]	2020	Chance-constrained programming coupled with genetic algorithm	24-hour period	33-bus test distribution system	Uncoordinated charging with various charging scenarios

of EVs controllability on the investment decisions. Hourly MILP capacity expansion model with unit commitment and economic dispatch was also utilized in [52] to evaluate the benefit from PHEVs controlled charging strategy in the NYISO system's expansion planning. In [60], the sensitivity of the generation portfolio investments on the EV and PV deployment was evaluated using Monte-Carlo based scenario modelling with the case study of the Australian National Electricity Market. In [8], the power systems of Texas, Sweden, Finland, Germany, and Ireland were represented and analyzed with unit commitment and capacity expansion models under uncoordinated and coordinated charging schemes. Some of these studies focused on the cooperation of EV fleet with other generation technologies and their potential to support VRE integration in power systems. Borba *et al.* [61] assessed the suitability of a controllable electric vehicle fleet to integrate and balance the large-scale wind power capacity deployment in northeastern Brazil. Mehrjerdi [62] analyzed the microgrid multistage capacity expansion problem with integrated electric vehicle charging station, solar PV, and battery energy storage. Furthermore, some of the models also included a detailed representation of the distribution system's assets in the modelling framework. In [7] the MILP model of power system expansion planning was deployed to evaluate the impact of EVs on the distribution system with charging stations, storages, and distributed energy resources. An adaptive robust optimization model, formulated as MILP, was used in [63] to determine the least-cost investment planning of charging stations, solar units, and battery storage, considering long-term uncertainty and short-term meteorological variability. Banol Arias *et al.* [64] focused on the small scale local distribution system expansion planning, co-optimized with the least-cost allocation of the charging stations. The model was formulated as MILP and considered the uncertainties of conventional loads as well as EV demand. Distribution level expansion planning was also analyzed in [65]. A combination of particle swarm optimization and tabu search was deployed to evaluate the system's operational costs, losses, and emissions, while integrating renewable energy sources, storage facilities and EVs. In [66], planning of the PV capacities and charging stations is performed with stochastic chance-constrained programming coupled with genetic algorithm. A summary of the modeling studies is presented in Table 3.

A review of the modeling literature indicates that long term optimization models based on the MILP approach are the most popular tool to evaluate the impact of EV load on the power system. These models are characterized with easy to formulate (linear) form, a wide range of available solvers and guarantee to obtain global optimum. Considering a wide range of advantages similar approach has been applied in this study.

III. METHODOLOGY

Figure 1 illustrates the key methodological steps undertaken in this study. The analytical process started with obtaining annual forecasts of electricity demand for each EV mode over the investigated horizon. Subsequently, the typical charging profiles were assumed for each mode under various charging strategies. Afterwards, the annual charging demand and normalized profiles were combined to generate EV load curves for typical days that are incorporated in the planning model. Then, least-cost generation and expansion plans were developed considering detailed technological, economic and environmental parameters of the power system. Finally, the key incremental parameters were calculated using outcomes of the modelling process to evaluate the critical impacts of the EV deployment. Key steps of the methodological process are described in the subsequent sections.

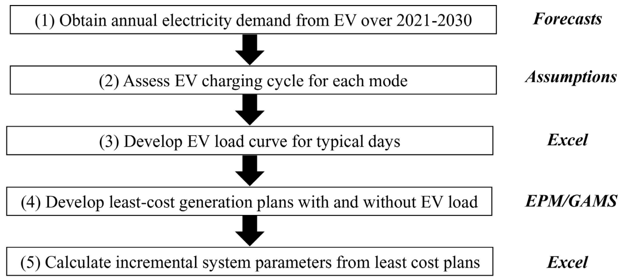

FIGURE 1. Key methodological steps.

A. EV LOAD AND CHARGING SCENARIOS

The first step in generating hourly EV load involves estimating annual electricity demand from each mode and type of vehicle. At this stage, two key inputs include a forecast number of EVs by mode and assumed battery capacity per vehicle type (in kWh). Annual electricity demand for EV charging depends on the structure of the market and dominant mode in the EV stock. Passenger light-duty vehicles, light commercial vehicles, buses, trucks as well as electric two- or three-wheelers will have not only distinct battery capacities and designated chargers, but also their daily charging schemes will change depending on the intended use, charging solution (wired, wireless or battery swapping) or charger availability.

To assess the impact of the additional demand on the daily peak and load profile, the annual demand needs to be converted into hourly load cycles based on a series of assumptions. First, charging cycles and levels must be defined for each mode. This includes defining the powers of the various types of chargers as well as the percentage of vehicles using specific chargers. Finally, the charging scenarios are constructed to develop final EV load cycles. In this study, two EV charging scenarios are considered: uncoordinated and optimized. In all EV charging scenarios, the total demand is derived from the baseline scenario without any transport electrification (henceforth referred to as the "No EV Load" scenario, plus the incremental addition from EV deployment.

In the uncoordinated scenario, most of the charging occurs during the evening hours, representing the typical time with the highest frequency of such events according to historical data. Specifically, we have assumed that:

- Most two-wheeler owners will plug in their EV after coming home from work. Therefore, the uncoordinated scenario considers 20% of electric two-wheeler fleet to perform level-1 charging at $\sim$ 1 kW peak power (for up to 3 hours) and 10% level-2 charging at $\sim$ 6kW peak power (up to 1 hour) every day starting at 6 pm
- 10% of electric cars will charge daily at level-2 ($\sim$7 kW peak power for up to 10 hours) and 10% at level-3 ($\sim$ 25 kW peak power up to 3 hours) starting at 6 pm
- The entire EV bus fleet is recharged every day through fast charging ($\sim$ 45 kW peak power for 8 hours), with half of them starting at 6 pm and the other half at 11 pm.

Figure 2 shows the baseline (before EVs load) and incremental EVs load for 30% of the vehicles for a typical working day in 2030, estimated as part of our work. While the additional volume of electricity consumption is relatively small ($\sim$3%), an increase in evening peak for an uncoordinated charging regime can be an order of magnitude higher.

As shown in Figure 2, the additional electricity demand from EVs can shift the daily peak from noon to the evening in the uncoordinated scenario.

In the optimized scenario, the model optimally distributes part of an EV load among hours to achieve the least-cost outcome. The optimization of the load is unidirectional, similar to the application of V1G technologies. The goal of the

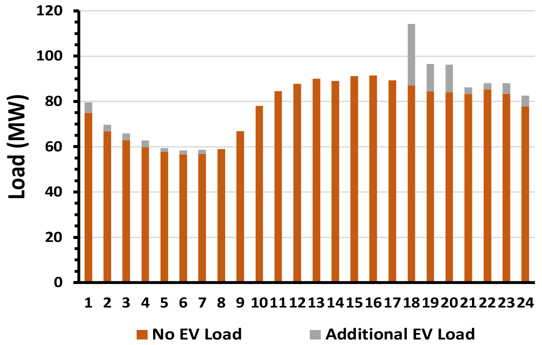

FIGURE 2. **Load in malé on a typical working day for 2030: baseline (no EV) and EV load.**

optimized scenario is to estimate the benefits of centralized charging by allowing the model to shift load not only across the hours but also balance it across the zones of the system. The EV charging optimization needs to observe the following three additional constraints in addition to observing restrictions on the timing of charging for different categories of different EV categories:

- The daily energy demand in the optimized EV scenario is equal to the daily energy demand in the uncoordinated EV charging scenario, i.e., the total charging load for the day remains the same as uncoordinated charging regime;
- The hourly electricity consumption from EV charging must be larger than 1% of the daily required electricity for EV charging which sets a minimum charging requirement; and
- The hourly electricity consumption from EV charging must be lower than 50% of the daily required electricity for EV charging, which sets a maximum charging load for any hour.

Finally, we also consider an optimized EV-CO_2 limits scenario, where the model optimizes the EV charging load but applies a CO_2 emissions limit for each year of the modelling period. The yearly CO_2 emissions in this optimized EV-CO_2 limit scenario cannot be higher than for the baseline (No EV Load). In other words, we explore a carbon-neutral case in which the additional EV load does not increase emissions to understand the system cost and investment implications.

B. OPTIMIZATION MODEL

In this study, the Electricity Planning Model (EPM) is deployed as a least-cost planning optimization framework for assessing the impact of additional EV load. EPM is formulated as a single mixed integer linear programming model for all years and implemented in GAMS [67] environment. It performs a systemwide multi-year planning optimization to determine:

- The optimal generation and transmission capacity addition for the system over the next 10-20 years.
- How generators should be dispatched including solar/wind subject to their availability profile and dispatchability.
- Flows among the nodes/zones, subjected to transmission limits.
- Optimal capacity of storage and how storage units should be operated to provide energy arbitrage and reserve services; and
- Allocation of spinning and capacity reserves to ensure adequacy and security of the system.

EPM is used to develop a baseline least-cost generation plan without further transport electrification and alternative generation plans with incremental EV load for the period from 2021 to 2030 for uncoordinated and optimized EV charging scenarios. Key outputs from the model include the net present value (NPV) of the system costs, annual CO_2 emissions, required capacity additions and associated investments, and fuel costs.

Equations 1-8 present the key formulations of the EPM model that are relevant for the present EV analysis. A complete formulation of the model is available in reference [68]. The objective function of the model constitutes NPV of all generation related costs discounted by the discount factor DF. First, the NPV covers $CAPEX$ costs applicable to newly build thermal, renewable and storage units. $CAPEX$ value is annualized with the capital recovery factor (CRF). Second, it comprises $OPEX$ costs, which include both operation and maintenance (O&M) expenses and fuel costs. Finally, NPV covers penalties θ^{USE} and $\theta^{Surplus}$ for unserved and surplus energy in each zone z.

$$
\begin{aligned}
NPV = & \sum_{g,y} \left(DF_y \cdot CRF_g \cdot CAPEX_g \cdot Cap_{g,y}\right) \\
& + \sum_{g,y,q,d,t} \left(DF_y \cdot OPEX_{g,y,q,d,t} \cdot Gen_{g,y,q,d,t}\right) \\
& + \sum_{z,y,q,d,t} \left(DF_y \cdot USE_{z,y,q,d,t} \cdot \theta^{USE}\right) \\
& + \sum_{z,y,q,d,t} \left(DF_y \cdot Surplus_{z,y,q,d,t} \cdot \theta^{Surplus}\right) \qquad (1)
\end{aligned}
$$

Equation 2 imposes the limit on the generation output $Gen_{g,y,q,d,t}$ of each unit g in every hour t, day d, season q and year y. Output is constrained by the product of installed capacity $Cap_{g,y}$ and capacity factor $CF_{g,y,q,d,t}$.

$$Gen_{g,y,q,d,t} \leq Cap_{g,y} \cdot CF_{g,y,q,d,t} \quad \forall g, y, q, d, t \qquad (2)$$

Equation 3 restricts the hourly transfer of power $Trans_{z,z',y,q,d,t}$ between two adjacent zones z and z' with parameter $TransLimit_{z,z',y,q}$ based on the technical limitations of lines in the system.

$$Trans_{z,z',y,q,d,t} \leq TransLimit_{z,z',y,q} \quad \forall z, z', y, q \qquad (3)$$

Demand supply balance in each zone and timestep is represented by Equation 4. It includes the generator's output (mapping between zones and generators is represented with a set ψ^z), surplus and unserved power, storage outputs and injections as well as transmission connectivity between the zones. Demand (total load) comprises two parts: base demand $Demand_{z,y,q,d,t}$ and additional EV charging load $EVLoad_{z,m,y,q,d,t}$.

$$\begin{aligned}\sum_{g\in\psi^z} & Gen_{g,y,q,d,t} - Surplus_{z,y,q,d,t} \\ & + \sum_{g\in\psi^z, g\in\psi^B} BStorOut_{g,y,q,d,t}\cdot\eta^B \\ & - \sum_{z'} Trans_{z,z',y,q,d,t} + \sum_{z'}\left(Trans_{z,z',y,q,d,t}\cdot\eta^T\right) \\ & - \sum_{g\in\Psi^z, g\in\Psi^B} BStorIn_{g,y,q,d,t} + USE_{z,y,q,d,t} \\ \leq & \; Demand_{z,y,q,d,t} + \sum_m EVLoad_{z,m,y,q,d,t} \quad \forall z,y,q,d,t\end{aligned} \tag{4}$$

$EVLoad_{z,m,y,q,d,t}$ is an input parameter for each transport mode m (two-wheelers, cars, and buses) in the uncoordinated scenario. We assume centralized charging of electric buses in all scenarios with further EV deployment. Therefore, the additional load required to charge electric buses remains an exogenously defined parameter in all scenarios with further EV roll-out. However, the additional charging load $EVLoad_{z,m,y,q,d,t}$ is a *variable* for electric two-wheelers and cars when considering optimized EV charging. Our study assumes charging of these two-wheelers and cars across the entire network that can be spread out (and thus optimized) to avoid overly concentrating the load from charging these vehicles around the peak hour. In other words, under optimized charging the model will determine the optimal balance between centralized charging and distributed charging of the two-wheeler and cars.

Equations 5-7 represent EV load specific constraints under optimized charging. Equation 5 ensures that the sum of optimized load across all zones is equal to the predefined value of daily EV demand in the system $EVLoad^{daily}_{m,y,q,d}$. Equation 6 imposes the lower bound on the hourly EV load in each zone z and hour h. Minimum optimized load is proportional to the base electricity demand $Demand_{z,y,q,d,t}$ using the scalar δ^{EVmin}, which for this study is defined as 0.01. Finally, Equation 7 imposes the upper limit on the amount of load allocated to one zone in each hour, proportional to the product of daily EV load $EVLoad^{daily}_{m,y,q,d}$ and factor δ^{EVmax} (set to 0.5 for this study).

$$\sum_{z,t} EVLoad_{z,m,y,q,d,t} = EVLoad^{daily}_{m,y,q,d} \quad \forall m,q,d,y \tag{5}$$

$$EVLoad_{z,m,y,q,d,t} \geq \frac{Demand_{z,y,q,d,t}}{\sum_z Demand_{z,y,q,d,t}}\cdot EVLoad^{daily}_{m,y,q,d}\cdot\delta^{EVmin} \quad \forall z,m,q,d,y,t \tag{6}$$

$$EVLoad_{z,m,y,q,d,t} \leq EVLoad^{daily}_{m,y,q,d}\cdot\delta^{EVmax} \quad \forall z,m,q,d,y,t \tag{7}$$

Equation 8 provides the capacity balance of each technology g in year y, excluding the first year of the planning horizon (represented as $FirstYear$). The capacity in the specific year is defined as a sum of capacity in the preceding year $Cap_{g,y-1}$ and newly constructed capacity $Build_{g,y}$.

$$Cap_{g,y} = Cap_{g,y-1} + Build_{g,y} \quad \forall g,\ y \neq FirstYear \tag{8}$$

Equation 9 constrains the amount of energy stored in each timestep $BStorage_{g,y,q,d,t}$ in-unit $g \in \Psi^B$ (where set Ψ^B includes the storage units). Equations 10 and 11 define the balance of the storage considering the output of storage unit $BStorOut_{g,y,q,d,t}$ and storage charging $BStorIn_{g,y,q,d,t}$. All storages are considered to be empty in the first hour of each day d mainly because the planning model works with non-adjacent representative days, and the storage optimization is restricted to each daily cycle independent of other days.

$$BStorage_{g,y,q,d,t} \leq Cap_{g,y}\ \forall g\in\Psi^B, y,q,d,t \tag{9}$$

$$\begin{aligned}BStorage_{g,y,q,d,t} = & BStorIn_{g,y,q,d,t} - BStorOut_{g,y,q,d,t} \\ & + BStorage_{g,y,q,d,t-1} \\ & \times\forall g\in\Psi^B, y,q,d,t\neq FirstHour\end{aligned} \tag{10}$$

$$\begin{aligned}BStorage_{g,y,q,d,t} = & BStorIn_{g,y,q,d,t} - BStorOut_{g,y,q,d,t} \\ & \times\forall g\in\Psi^B, y,q,d,t = FirstHour\end{aligned} \tag{11}$$

For network stability reasons, in Equation 12, the total installed capacity of rooftop solar PV is limited to 50% of the yearly peak load in any load zone $Demand^{max}_{z,y}$.

$$\sum_{g\in\Psi^z, g\in\Psi^{RoofPV}} Cap_{g,y} \leq 0.5\cdot Demand^{max}_{z,y} \quad \forall z,y \tag{12}$$

IV. CASE STUDY FOR MALDIVES (MALÉ)

A. KEY INPUTS

1) EV PENETRATION

The study focuses on the impact of EV fleet located in the system of Malé, the capital and most populous city in Maldives where 50% of each type of EV is located and charged. Table 4 summarizes the number of EVs by type and the associated electricity demand for both the whole Maldives and Malé up to 2030.

The projected number of two-wheelers in the Maldives split between fossil-fueled two-wheelers (non-EV) and electric two-wheelers (EV) up to 2030, as shown in Figure 3. The number of electric two-wheelers is expected to increase from 5,377 in 2021 to 49,977 in 2030. The study assumes an average 2.5 kWh battery capacity for the electric two-wheelers.

The number of electric cars in the Maldives is forecasted to grow from 546 in 2021 to 3,444 in 2030 (Figure 4). Electric cars are assumed to have batteries with an average storage capacity of 60 kWh.

We assume 15 new electric buses per year in Malé as of 2021, yielding a total electric bus fleet of 150 buses

TABLE 4. EV projections for the maldives and malé by vehicle type (number and total capacity in kWh).

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maldives										
Electric two-wheelers										
Number (-)	5,377	8,935	12,843	17,100	21,707	26,662	31,967	37,621	43,625	49,977
Capacity (kWh)	14,285	22,338	32,108	42,751	54,267	66,656	79,918	94,054	109,062	124,943
Cars										
Number (-)	328	546	784	1,043	1,324	1,625	1,947	2,290	2,654	3,038
Capacity (kWh)	19,680	32,735	47,044	62,607	79,423	97,492	116,816	137,393	159,223	182,307
Buses										
Number (-)	15	30	45	60	75	90	105	120	135	150
Capacity (kWh)	5,250	10,500	15,750	21,000	26,250	31,500	36,750	42,000	47,250	52,500
Malé										
Electric two-wheelers										
Number (-)	2,857	4,468	6,422	8,550	10,853	13,331	15,984	18,811	21,812	24,989
Capacity (kWh)	7,143	11,169	16,054	21,375	27,134	33,328	39,959	47,027	54,531	62,472
Cars										
Number (-)	273	392	522	662	812	973	1,145	1,327	1,519	1,722
Capacity (kWh)	16,368	23,522	31,303	39,711	48,746	58,408	68,696	79,611	91,153	103,322
Buses										
Number (-)	8	15	23	30	38	45	53	60	68	75
Capacity (kWh)	2,625	5,250	7,875	10,500	13,125	15,750	18,375	21,000	23,625	26,250

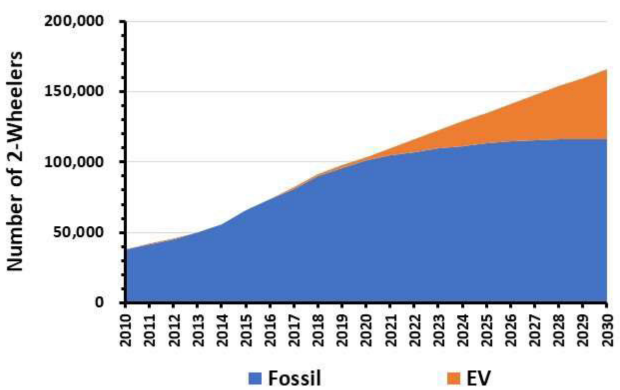

FIGURE 3. Historic (up to 2018) and forecast number of two-wheelers in the maldives.

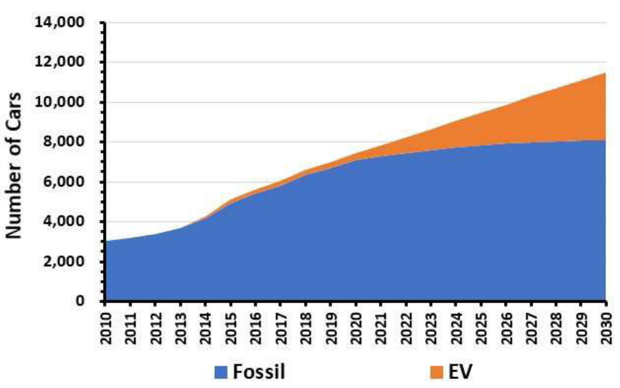

FIGURE 4. Historic (up to 2018) and forecast number of cars in the maldives. *Note:* Historic data is from maldives ministry of transport.

by 2030 since currently there are no electric buses in the Maldives. These buses are expected to have an average battery capacity of 350 kWh and are being recharged through fast charging (peak power of 45 kW) every evening or night.

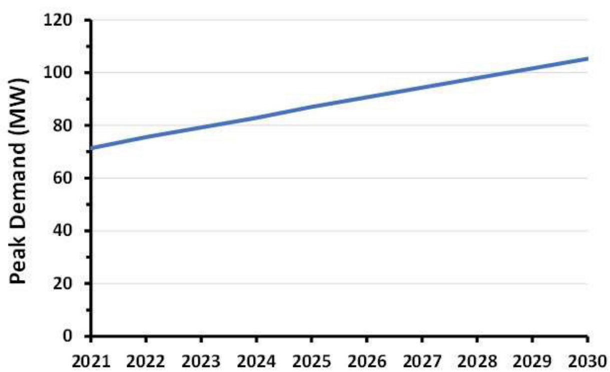

FIGURE 5. Baseline peak demand projection for malé.

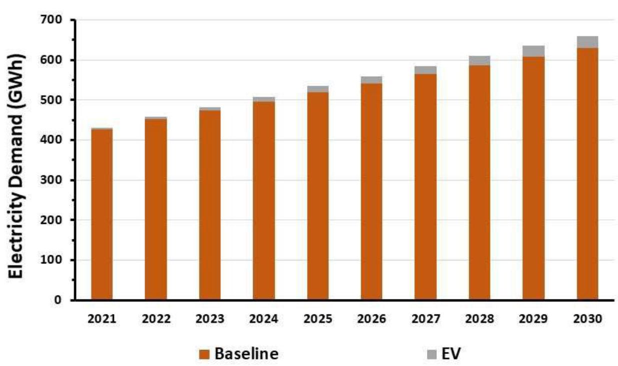

FIGURE 6. Energy requirement projection for malé – baseline and incremental EV demand.

2) PEAK POWER AND ELECTRICITY DEMAND IN MALÉ

Baseline peak demand for Malé in the absence of further transport electrification is expected to grow at 4.4% per year from 71 MW in 2021 to 105 MW in 2030 (Figure 5). The associated electricity demand grows from 427 GWh in 2021 to 630 GWh in 2030 (Figure 6).

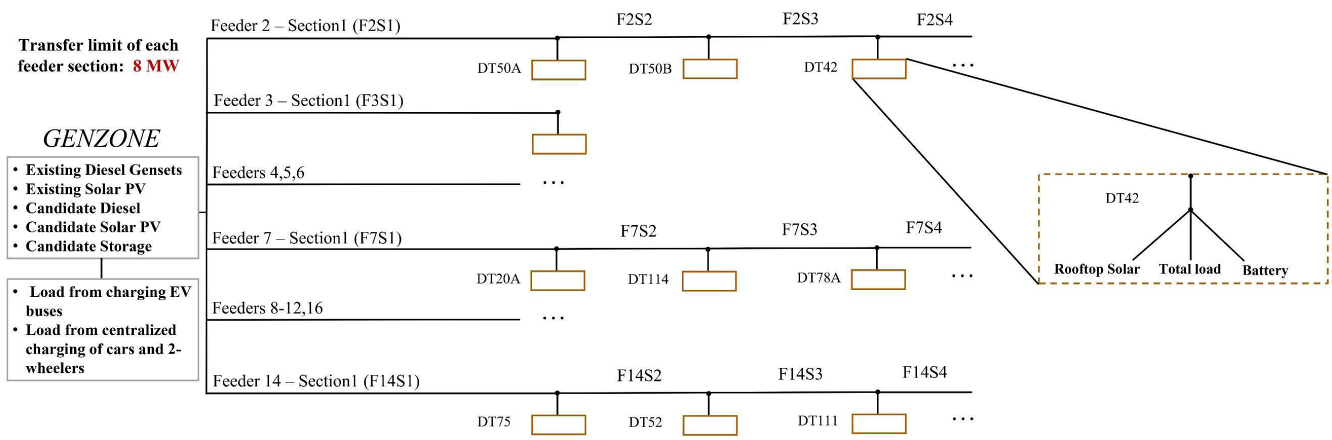

FIGURE 7. Schematic representation of the malé distribution network with candidate additions of rooftop solar PV and battery energy storage systems at customers sites. Feeders 2, 7, and 14 were split into their different subsections. The remaining 10 feeders are modelled as single nodes. The power transfer limit of each feeder section is 8 MW. Note: * Load from centralized charging of cars and two-wheelers in GENZONE is only considered in the optimized scenario.

Gradual electrification of vehicles up to 30% of the fleet or ∼ 26,800 EVs out of a total fleet of 89,000 vehicles in Malé by 2030 increases the incremental EV energy requirement from 4 GWh in 2021 to 31 GWh in 2030 (Figure 6, labelled as EV). Total electricity demand is therefore expected to grow from (427 + 4 =) 431 GWh in 2021 to (630 + 31 =) 661 GWh in 2030.

Annual electricity demand is modelled with 12 representative days with 3 days per quarter (1 peak day, 1 minimum day and 1 average day) in hourly resolution. The model assumes a constant load profile for each representative day of the next ten years (2021-2030) at each distribution node (substation). The load profile for each node for each of the three representative days in the second quarter (April to May) is based on the recorded hourly loads of April 2019. Load profiles in the other quarters (quarters 1, 2, and 4) were scaled based on the ratio of total generation in that quarter to the total generation in Malé for quarter 2. Peak demand at each distribution node has the same growth rate as the entire system. The study assumes that the additional EV load at each distribution node is split proportionally to each distribution node's contribution to the system peak demand in the absence of any further electrification.

3) NETWORK REPRESENTATION

The schematic representation of Malé's medium voltage distribution network is based on STELCO's Malé single line diagram from October 2019. Out of the 13 feeders, 3 feeders (feeders 2, 7, and 14) were split into subsections with the associated distribution transformers to investigate the possible overloading of transformers and feeder section capacity constraints. The assumed power transfer limit of each feeder subsection (labelled as F_xS_y in Figure 7) is 8 MW (Figure 7). STELCO also provided power transfer limits in MW for the distribution transformers (labelled as DTzz in Figure 7) along with these 3 feeders. The remaining 10 feeders were modelled as single nodes with a feeder power transfer limit of 8 MW (Figure 7). The model is allowed to deploy new rooftop solar PV and grid connected batteries at each distribution node. Existing diesel gensets and solar PV capacity are connected to all feeders. Connection to all feeders is schematically represented by placing existing diesel units and solar PV in the zone labelled as GENZONE (Figure 7). New candidate diesel or utility solar units are assumed to be deployed in the same GENZONE. We assume that network constraints are absent between the GENZONE and the first subsection of each feeder (F_xS_1). Incremental load from EV buses charging is connected to GENZONE to represent centralized charging of these vehicles. Total load, including base demand and the incremental EV load from two-wheelers and cars, is connected to each distribution node. This incremental load is a fixed parameter in the uncoordinated scenario and a variable in the optimized scenario. In the optimized charging scenario, the two-wheelers and cars can be charged through both decentralized charging in the distribution network and centralized charging. The centralized charging is represented as an additional load in GENZONE.

4) GENERATOR CHARACTERISTICS

Table 5 lists the cost and operational characteristics for both existing and candidate diesel gensets (DG) and utility-scale solar PV taken from the Energy Storage Roadmap for the Maldives [69]. Rooftop solar PV is assumed to have a capital cost of 3.0 million USD per MW in line with recent IRENA projections [70] and economic life of 20 years. CAPEX of the battery energy storage systems (BESS) is assumed to be 250 USD per kWh with an economic life of 15 years. For candidate generators, the column "Capacity" shows the maximum capacity limit by 2030. The maximum utility PV deployment of 5 MW by 2030 is based on a previous PV potential assessment [69]. Diesel prices are assumed to increase in line with the latest WB Commodity

TABLE 5. Generator operating and cost characteristics.

Plant	Status	Zone	COD	Capacity (MW)	Heat rate (MMBTU/MWh)	FOM (USD/MW/year)	VOM (USD/MWh)	CAPEX (mUSD/MW)
DG	Existing	GENZONE		82	9.37	38,000	7.0	-
SolarPV	Existing	GENZONE		0.67	-	10,000	-	-
Generic DG	Candidate	GENZONE	2021	100	9.0	76,000	7.0	1.20
Utility PV	Candidate	GENZONE	2023	5	-	5,000	-	1.20
Rooftop PV	Candidate	Each distribution node	2021	20	-	10,000	-	3.0
BESS (non-battery costs)*	Candidate	Each distribution node/ GENZONE	2021	10	-	14,000	-	0.3

Note: *Capex for battery pack is taken as 250 USD/kWh – the table shows only the non-battery costs component of the battery energy storage system in million USD per MW; efficiency of 85%. The World Bank report "Economic Analysis of Battery Energy Storage Systems" explains the difference between the battery pack and non-battery pack costs in detail [71]. COD = Commercial Operation Date; FOM = Fixed Operation and Maintenance Cost; VOM = Variable Operation and Maintenance Cost.

TABLE 6. Overview of scenarios (2021-2030).

Scenario	EV Load	EV Charging Constraints
Baseline	No further transport electrification: $EVLoad_{z,m,y,q,d,t} = 0$.	N/A (no further EV roll-out)
Uncoordinated EV charging	• Deterministic calculation of EV charging load across all transport modes • Centralized charging for buses • Decentralized charging for two-wheelers and cars	N/A (EV load is an input parameter for each transportation mode)
Optimized EV charging	• Centralized charging for buses (same load as for uncoordinated EV charging) • ***Optimized charging for two-wheelers and cars across the entire network (optimal mix of centralized and decentralized charging)***	For optimized charging of two-wheelers and cars: • Same daily energy demand as for uncoordinated EV charging scenario • Hourly consumption from charging must be larger than 1% of the daily energy demand for charging • Hourly consumption from charging must be smaller than 50% of the daily charging requirement
Optimized EV charging – CO_2 limits	• Same methodology as for optimized EV charging	Same assumptions as for optimized EV with the following additional constraint: • CO_2 emissions in each year of the forecast cannot be higher than the corresponding emissions for the baseline

Note: All scenarios are subject to the constraints in Equations (2) - (4), (8)-(12).

Market Outlook starting from the reported 2019 diesel price of 21.5 USD/GJ [70]. The solar availability profile in Malé for both utility-scale PV and rooftop PV is taken from the Global Solar Atlas (2020 data). The average solar capacity factor in the model is 18%. Table 6 summarizes four key scenarios in terms of EV load and associated constraints.

B. DISCUSSION OF RESULTS

The optimal generation plan in the baseline scenario without further EV deployment yields a total net present value of 867 million USD in system costs at a 10% discount rate over the 2021 to 2030 period (Table 7). Total power sector generation emissions stand at 3,173 kton CO_2. The combined existing and new capacity will be able to meet almost the entire demand by 2030 but for a relatively small part of it (<0.2% of total demand over the 2021-2030 period). The deployed capacity to meet increased demand by 2030 includes 54 MW of rooftop PV and 2.5 MW of BESS (14 MWh) in the distribution network together with 5 MW of utility-scale PV and 4 MW of new diesel units (Figure 8). Most of the new rooftop PV (47 MW out of 54 MW) is built in the first six years of the modelling period.

The expected contribution of renewables (rooftop and utility-scale PV) will increase over the next 10 years up to 14% of the generation mix by 2030 (Figure 9. The contribution from batteries to energy mix is marginal and is about 1% of the annual output by 2030.

Uncoordinated EV charging increases the total electricity demand by 3.1% (+166 GWh) relative to the baseline scenario over the 2021-2030 period. The increased electricity demand causes a 3.5% increase in system costs (+30 million USD).

The increase in system costs mainly stems from increased fuel costs due to increased diesel generation and, to a lesser extent, increased capital investment (Table 7). The additional

TABLE 7. Comparison of different EV charging scenarios for malé (2021 – 2030).

Result	Baseline	Uncoordinated EV Charging	Optimized EV Charging	Optimized EV Charging with CO_2 limits
Demand (GWh)	5,299	5,465 (+166)	5,465 (+166)	5,465 (+166)
NPV of System Costs* (million USD 2021)	867	897 (+30)	892 (+25)	919 (+52)
Investment CAPEX (million USD)**	229	265 (+36)	231 (+2)	255 (+26)
New Capacity (MW)	111	140 (+29)	113 (+2)	131 (+20)
Unserved Demand (GWh)***	10	11 (+1)	10 (-)	79 (+69)
Emissions (kton CO_2)	3,173	3,244 (+87)	3,287 (+114)	0 (-3,173)
Production	5,351	5,542 (+191)	5,518 (+166)	5,436 (+85)
Diesel	4,677	4,788 (+138)	4,846 (+169)	4,750(+73)
Rooftop PV	594	626 (+31)	591 (-3)	613 (+19)
Utility PV	73	73 (-)	73 (-)	73 (-)
BESS	7	28 (+13)	7(-)	0 (-7)

Note: *Discount rate is 10%.
** Total capex. Please note that the planning model considers capital costs in annualized terms for 2021-2030 which is below the total capex.
*** Unserved energy penalized at 1000 USD/MWh following [69]

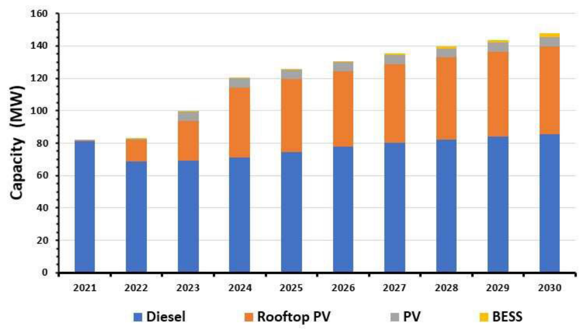

FIGURE 8. Optimized baseline generation capacity for malé (2021-2030).

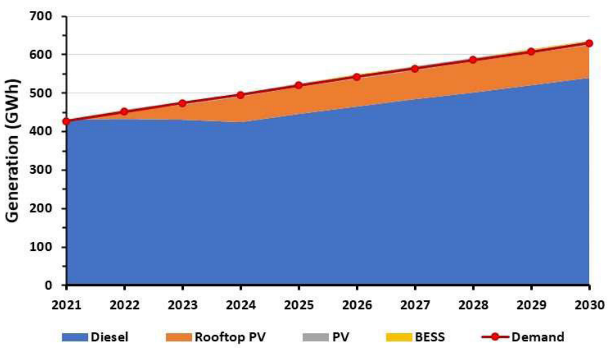

FIGURE 9. Baseline generation mix for malé (2021-2030).

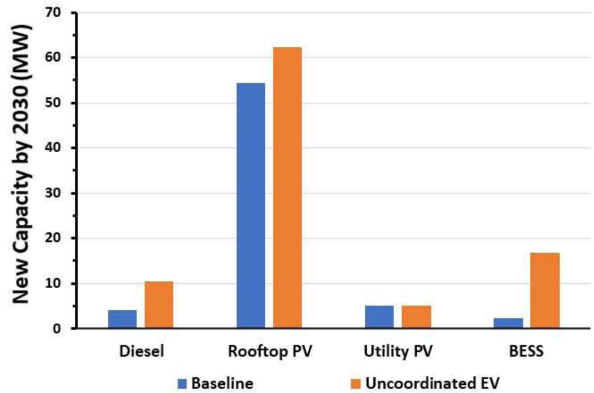

FIGURE 10. Comparison of the optimized capacity mix for malé: baseline vs. uncoordinated EV.

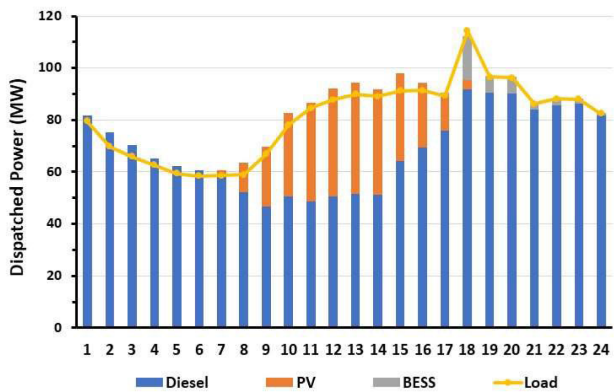

FIGURE 11. Hourly dispatch for malé in 2030 for an average day in the uncoordinated EV charging scenario.

demand is met through a combination of diesel, rooftop PV and BESS generation. The increased electricity generation from diesel units causes a 2.7% (+87 kton) increase in greenhouse gas emissions over the next 10 years. The higher capital expenditure results from the additional deployment of 8 MW rooftop PV, 15 MW BESS (34 MWh), and 6 MW diesel (Figure 10). Uncoordinated charging increases the evening peak by up to 12 MW in 2025 (+17%) and 27 MW (+31 %) in 2030. The higher peak demand is met through a combination of increased diesel and BESS output (Figure 11). BESS is charged through overproduction of rooftop PV during the day (7h – 16h) and diesel units during the night (Figure 11).

Optimized EV charging reduces the incremental cost of EV deployment relative to the baseline scenario for the power sector from 30 million USD in the uncoordinated EV charging scenario to 25 million USD, i.e., a 2.9% increase in system costs over the baseline NPV estimate. The optimized EV charging case incurs larger fuel costs than the uncoordinated scenario due to increased diesel generation (Table 7).

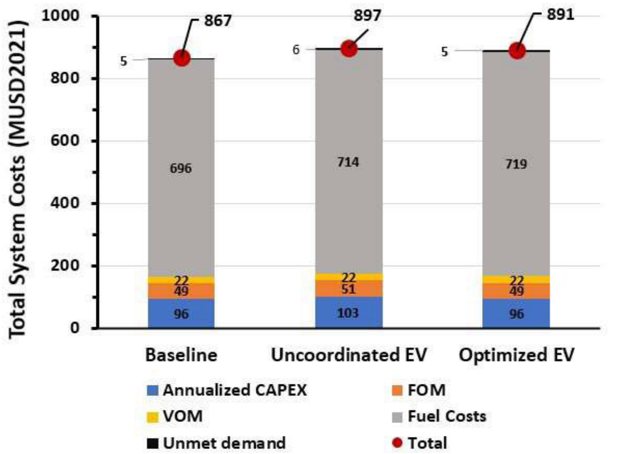

FIGURE 12. Comparison of total system costs (2021-2030) under different EV charging scenarios for malé.

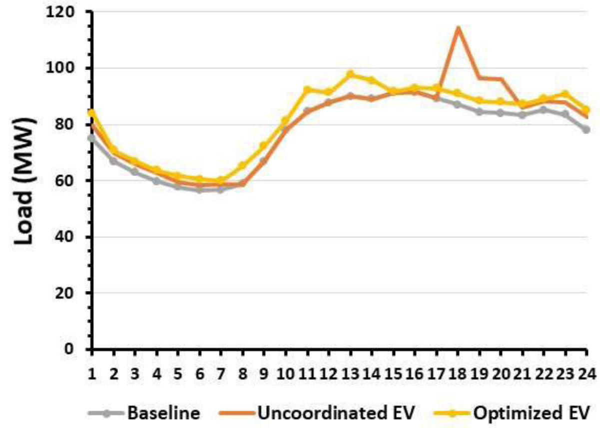

FIGURE 14. Hourly load for an average day in malé during quarter 2 in 2030 under different EV charging scenarios.

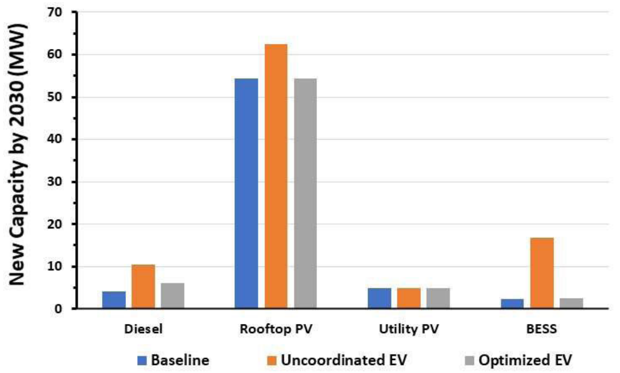

FIGURE 13. New capacity by 2030 under different EV charging scenarios for malé.

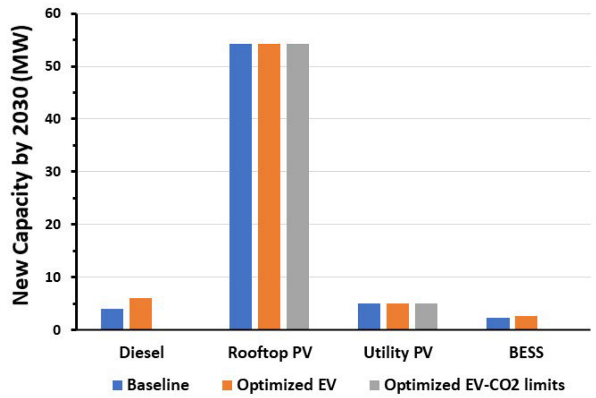

FIGURE 15. New capacity by 2030 under different EV charging scenarios for malé.

The increase in fuel costs (+5 million USD) in the coordinated charging scenario compared to the uncoordinated scenario is more than offset by a reduction in capital cost (−7 million USD) and operating costs (−2 million USD), leading to a net 5 million cost decrease relative to the uncoordinated case (Figure 12).

The optimized charging scenario has a similar capacity expansion plan as the baseline. The only difference is the 2 MW higher diesel deployment over the 2021-2030 period (Figure 13). Put differently, the optimized scenario flattens the EV load sufficiently to warrant very little increase in capacity relative to the baseline and uses more diesel generation to meet this load.

This is evident from Figure 14 that shows optimized EV charging removes the evening spike from concentrated EV charging in the uncoordinated scenario by distributing the EV charging load throughout the day. Optimized charging smoothens the load profile and reduces systems costs due to reduced CAPEX needs. On the flipside, the incremental EV load is mainly met by previously unused diesel capacity, especially during periods of high solar availability (11h – 15h) where even more idle diesel capacity is available to meet incremental EV load (Figure 14). The increased diesel capacity and generation in the optimized charging scenario further increase CO_2 emission up to 3,287 kton over the 2021-2030 or a 3.6 % increase vs. the baseline.

We, therefore, also explored a carbon-neutral scenario by constraining the optimized EV scenario CO_2 emissions limits to the baseline emissions. This proved to be an expensive constraint that doubles the incremental cost to 52 million USD over the baseline (Table 7). Limiting the CO_2 emissions in the optimized EV scenario not only results in increased solar PV deployment in the distribution network but also increases unmet demand during high load hours in the evening. The combination of both effects increases the total system cost by 6.0% over the 2021-2030 period. However, it is interesting to note that even with the carbon neutrality criterion imposed, optimized charging of EV leads to distributing the load more evenly and eliminates the need for BESS, albeit at the expense of increasing (economic) load shed (Figure 15). Although we do not explore the demand response options as part of this study, such options for cooling loads etc., may be a highly potent option to manage other loads.

V. CONCLUDING REMARKS

Electrification of transport is one of the critical planks of decarbonization and is a welcome addition in many other terms too for oil-importing countries with heavily polluted cities. It is, however, going to place an additional burden on power systems requiring more generation, storage, transmission and distribution capacity, more generation from expensive peaking plants and potentially more emissions from the power sector. There is a serious need for planning ahead so that these impacts can be minimized through measures like optimized/coordinated charging of EV loads and intensifying RE and storage programs.

In this paper, we present the methodology to incorporate the EV charging demand in the long-term capacity expansion model and evaluate the impact of the additional load on the power system operation, costs, emissions and investment decisions. We have firstly surveyed the academic and industry literature that mostly discuss the experience with EV in the developed world to provide an understanding of the nature and magnitude of EV impacts on generation, transmission and distribution. Some of the studies do point to a substantial need to upgrade the distribution network that may add in excess of 5000 USD per EV. Furthermore, capacity expansion studies indicate that investments in new flexible gas units are needed in the system after large scale EV introduction with uncoordinated charging. In the developing world, these impacts may be even more serious because of the dilapidated nature of the distribution system, rapidly growing electricity demand, a lack of sufficient peaking capacity and inadequate level of RE penetration to meet the added load without increasing emissions. Nevertheless, literature review confirms that smart charging strategies, including TOU tariffs, coordinated unidirectional charging and V2G technologies, are effective ways of mitigating the power system stresses, reducing required investments to provide reliable electricity supply and avoiding CO2 emissions from a new load. Especially in the systems with already high investments requirements, due to increasing demand and poor infrastructure, load management approaches can be substantially more cost-effective compared to typical capacity expansion and grid reinforcement.

We have undertaken a planning study for the city of Malé in Maldives to explore these issues and inform a strategy around distributed RE, EV and BESS to augment the existing generation system in a way that does not require a massive upgrade to the distribution network. We have used the Electricity Planning Model (EPM) developed at the World Bank with some enhancements made to it to optimize EV charging load. There are three key questions we have tried to answer for Maldives: (a) what are the additional capital and operating cost and emissions implications of adding EV to the system? (b) does it help to plan for an optimized charging regime to contain some or all of these impacts sufficiently? and (c) can the Maldives system be made carbon-neutral for the additional EV load, and at what cost?

We have considered a moderate EV scenario that assumes 30% of the vehicles (primarily two-wheelers) will switch to EV by 2030, adding a modest ~3% to energy requirement on average over 2021-2030. However, the addition to evening peak hour load can be an order of magnitude higher if a substantial part of these vehicles is to be charged during the evening in an "uncoordinated" regime. This regime is compared and contrasted with a coordinated/optimized regime wherein the model distributes the EV load across the hours while observing constraints on minimum and maximum charging that is feasible and on timing requirements for different modes of transport.

Uncoordinated EV charging will increase total power system costs by ~3% (+ 30 million USD 2021) over the 2021-2030 period resulting from increased CAPEX for generation units and diesel fuel costs. Total undiscounted generation CAPEX will increase by 36 million USD (or 16% relative to a baseline of No EV load) as the system will require an additional 29 MW capacity by 2030 (8 MW rooftop PV, 15 MW BESS, 6 MW and diesel). Given that the 36 million USD additional generation investment is needed to electrify approximately 50,000 two-wheelers, 3,400 cars and 150 buses, about 500-600 USD in new generation investment is needed for every new EV (primarily two-wheelers) on the road over the next ten years in the Maldives. This is in fact a significant cost for a small system and represents around 50% of the cost of a new EV two-wheeler in the country.

Optimized EV charging will reduce the incremental cost to 25 million USD in discounted terms over 2021-2030. The incremental cost from Optimized EV is mainly due to increased fuel (diesel) costs, but it will cause an additional 114 kton CO_2 emissions compared to the baseline case. Optimized EV charging also causes 27 kton more CO_2 emissions than the uncoordinated EV charging scenario. New and emerging technologies such as smart charging, battery swapping, and VGI can enable/support the Optimized EV scenario and potentially expand its scope and limit the negative emissions impacts. However, these issues would require significant enhancements to the methodology and that data that do not exist at present and hence have not been explored.

Uncoordinated EV charging causes increased rooftop PV and BESS deployment together with increased RE generation to manage a sharp increase in the evening peak, whereas optimized EV favors increased diesel generation and capacity (+2 MW vs. baseline). The increased evening load under uncoordinated EV charging improves the business case for BESS or PV+BESS as local rooftop PV, and BESS avoids overloading feeders. The distribution network is able to cope with the EV load without requiring an upgrade of the feeders that we have studied. A thorough load flow analysis will still be needed to confirm this finding for the full network.

In summary, the study provided us with a number of useful insights. While it provided some comfort that the additional

EV load can be accommodated within the limitation of the 11 kV feeders studies, it also revealed a severe increase in generation capital requirement to meet the peak load. Optimized charging can contain this impact but presents a challenge of increasing emissions too. Although these conclusions are somewhat idiosyncratic to the Malé generation and network systems, the underlying issues are symptomatic to many cities in the developing world. The planning model and the framework around which these issues are addressed may need to be applied for a carefully planned development of EV penetration, including a fuller exploration of new and emerging technologies that can minimize potential ill-effects of EV load on the power systems.

These conclusions and insights lead to a few key recommendations for the key stakeholders involved in policy making, regulations and system planning and operation, namely:

- Policy making on EV should explicitly consider integrated energy sector-wide studies including decarbonization target for the sector as a whole. As the Maldives case study clearly demonstrate, the impact of additional EV demand on the power system is significant that requires careful planning, investment and operational changes that will require a long lead time.
- Power system planning should be used to exploit any flexibility that may be available in optimizing the EV load to minimize system cost, investment and emissions impacts. Bringing the EV roll out plan and power system plan closer is essential to understand the benefits of a more flexible EV charging and devise necessary incentive mechanisms. Given the resource constraints that typically prevail in developing countries, it is important not to overburden an already stressed system or extenuate investment requirements that are usually quite challenging to meet organic load growth.
- The impact on distribution system can be particularly severe that may in the limit require a complete overhaul of the system, e.g., to upgrade a substantial part of the 11 kV system to 22 kV. If this transition is not managed well, it may lead to a substantial increase in outages. Long-term planning analyses should be complemented with detailed load flow studies to evaluate the suitability of distribution and transmission system assets and uncover potential risks of overloading or failures.
- Theoretical studies prove that smart charging strategies provide an attractive way of avoiding expensive grid reinforcements with the large-scale deployment of EVs. Piloting new technologies is a useful way to check if some of the costly upgrades can be avoided and the planning analysis also provides a means to test the cost-benefit of these technologies.

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ADAM SUSKI received the B.S. degree in power engineering from Cracow University of Technology, Poland, in 2019. He is currently pursuing the M.S. degree in sustainable energy with the Technical University of Denmark. He is also working as a Temporary Consultant with ESMAP, The World Bank. His research interests include power system planning, optimization, sustainable energy, and energy access.

TOM REMY received the master's degree in international economics from KU Leuven, Belgium, and the Ph.D. degree in chemical engineering from the Vrije Universiteit Brussel, Belgium. He is currently an Extended Term Consultant with East Africa Unit, The World Bank. His research interests include power system planning, electricity market design, utility financial analysis, and low-carbon energy policies.

DEBABRATA CHATTOPADHYAY received the Ph.D. degree in power system from IGIDR, India. He is currently a Senior Energy Specialist with ESMAP, The World Bank, where he leads the Power Systems Planning Group. His research interests include power system optimization and electricity market design.

CHONG SUK SONG received the Ph.D. degree in power systems from Korea University, South Korea. He is currently an Energy Specialist with ESMAP, The World Bank. His research interests include power system planning, energy storage, and electric mobility.

IVAN JAQUES is currently a Senior Energy Specialist with South Asia Unit, The World Bank. He is also an Industrial Engineer with the University of Chile. His research interests include sustainable transport systems, industrial decarbonization, and innovation.

TAREK KESKES received the M.Sc. degree in electrical engineering and information technology from the Technical University of Munich, Germany. He is currently an Energy Specialist with ESMAP, The World Bank. His research interests include electric mobility and sustainable energy systems.

YANCHAO LI received the Ph.D. degree from The University of Manchester, U.K. She is currently an Energy Specialist with The World Bank. Her research interests include energy innovation, including electric mobility and vehicle-grid integration (VGI), and broader topics related to demand-side management (DSM).