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Assessing the Role of Renewables in Reducing Emissions in the Saudi Power Sector Using Mixed-Integer Optimization

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Key Points

Renewable energy (RE) technologies are viewed as a critical means of reducing power sector-related emissions. Using mixed-integer optimization, we evaluate the extent to which renewable energy reduces carbon emissions in the Saudi power sector.

We created a capacity expansion model, which simultaneously considers generation and transmission builds and covers a planning horizon up to 2040.

The simulated scenarios, which entailed retiring liquid fuels from the Saudi power sector and accounted for different gas prices, consider the following candidate build technologies: nuclear, gas, solar photovoltaics, wind, concentrated solar power with storage, and battery storage.

Renewables could reduce carbon emissions by 25%-41% by 2040, depending on the gas price. Within Saudi Arabia, renewable deployment could defer national gas supply expansion plans but not investment in expanding domestic gas transport capacity.

Under certain conditions when deploying significant renewable capacity, better transmission interconnection between regions manages renewable intermittency more cost-effectively than storage deployment.

1. Introduction

For decades, Saudi Arabia, like many countries around the world, has relied on fossil fuels for its power generation needs. The Kingdom's abundant energy resources have enabled it to establish strong industrial sectors and a higher quality of life for its citizens. Going forward, Saudi Arabia intends to reduce or eliminate its use of liquid fuels in power generation by diversifying its energy mix. This is mainly driven by three factors: (1) the Kingdom's commitment to reducing internal carbon emissions to combat climate change (Bradshaw, Van de Graaf, and Connolly 2019), (2) the potential for using liquid fuels in higher value-added activities (Matallah 2020), and (3) the emergence of new, cost-competitive power generation technologies (Steffen et al. 2020).

First, Saudi Arabia has committed to greater environmental sustainability. The Kingdom supports the circular carbon economy (CCE) concept as a pragmatic pathway for achieving climate change goals (Gallo et al. 2020). The CCE comprises four main principles (known as the four Rs): *reduce* the amount of carbon emitted, *reuse* carbon by capturing it and converting it so that it could be used as feedstock, or, otherwise, *recycle* carbon by transforming it (for example, into fertilizers or synthetic fuels), and *remove* carbon by storing it geologically or chemically.

Second, alternative power generation options displace liquid fuels that can be used in activities more valuable to the wider macroeconomy, including export to international markets at prevailing prices. According to a study by Blazquez et al. (2020), policies that aim to curb domestic oil consumption in the Kingdom have positive welfare impacts ranging from 6 United States (U.S.) dollars (US$) to US$56 per barrel of oil saved, even after considering the potential decrease in oil prices internationally due to the increase in Saudi oil exports.

The third reason enabling Saudi Arabia, and the rest of the world, to rely less on fossil fuels is advancements in the costs and performances of renewable technologies. Solar photovoltaic (PV) and wind generation, particularly, have experienced significant cost reductions in the past 20 years (Das, Hittinger, and Williams 2020). Furthermore, Saudi Arabia has excellent solar and wind resources, which further supports the financial case for renewables.

Electricity demand in the Kingdom has been steadily increasing both in terms of peak load and consumption (Mikayilov et al. 2020), propelled by population and economic growth. This has stagnated in the past few years due in part to energy price reforms that raised retail electricity rates for most sectors. Nonetheless, it is expected that demand will increase over the coming two decades due to economic growth and 'giga' projects, including the city of Neom and new touristic cities on the Red Sea.

Given the relatively long lead times and capital-intensive nature of power generation projects, planning is paramount. In this context, long-term models are helpful but mainly aim to minimize costs, while other factors can weigh in favor of more expensive options (Mehrabadi, Moghaddam, and Sheikh-El-Eslami 2020). The value of such models is in their ability to understand trends and identify general directions, rather than the exact absolute numerical estimates they produce (Felder 2016).

In this paper, we conduct a long-term capacity expansion study to assess the impacts of retiring liquid fuels from the Saudi power sector and the associated emission implications. Our research stems from the government's recent announcements that the Kingdom will fully rely on gas and renewables in the future for its power needs (Saudi Gazette 2020). This study is the first to explicitly assess the related costs and environmental impacts of this policy shift. Four additional aspects distinguish this paper from previous ones focusing on Saudi Arabia: (1) we use more recent data for the base year (2018 rather than 2015), (2) we employ integer optimization rather than the classic linear program approach, (3) we create a more granular model with respect to the regions and transmission connectivity within the Kingdom (we use six regions rather than four), and (4) we extend the horizon of the study until the year 2040.

This paper is organized as follows. In section 2, we discuss capacity expansion planning (CEP) models and explain their value, briefly review CEP models for regions outside the Kingdom, and then focus on those created for Saudi Arabia specifically. Section 3 explains the scenarios considered in our analysis and provides a detailed description of the model's creation. Section 4 presents the results of the simulation, followed by a discussion and contextualization. Section 5 concludes the paper.

2. Review and Context

2.1. Brief overview of the Saudi power sector

Saudi Arabia relies on fossil fuels to meet virtually all its demand for electricity (ECRA 2020). In 2019, the country generated 57% of its electricity from natural gas, 20% each from heavy fuel oil (HFO) and crude oil, and 3% from diesel. Since 2010, the share of gas in the fuel mix has risen sharply from 34%, reducing average emissions and increasing the efficiency of the Kingdom's power sector.

The Saudi Electricity and Cogeneration Regulatory Authority (ECRA) divides the Kingdom into four operational regions — eastern, central, western, and southern — across which the fuel-mix varies widely. Gas satisfies 97% of the energy needs in the eastern region but only 10% in the western region, while the southern region relies solely on liquid fuels.

Prior to recent price reforms, the Kingdom's electricity demand and peak load had been on upward trajectories for many years. Electricity consumption (i.e., power sold) rose from 215 terawatthours (TWh) in 2010 to around 300 TWh from 2015 onward (289 TWh in 2019). Similarly, peak load increased from around 44 gigawatts (GW) in 2010 to 62 GW in 2015 and has since hovered around this level. Higher energy prices introduced in early 2016, including tiered rates for the residential sector, partly explain the plateauing demand. For instance, the tariff for the lowest household tier roughly tripled after the reforms came into effect, from US$0.013 per kilowatthour (US$/kWh) to 0.048 US$/kWh.

2.2. Capacity expansion planning: general overview

Capacity expansion planning (CEP), also referred to as energy mix modeling, aims to minimize the cost of electricity production while considering fuel access and other constraints within a relatively long time horizon of 10 to 30 years and beyond (Wierzbowski, Lyzwa, and Musial 2016).

Effective emissions reduction targets require a clear view of how the power sector, which is generally highly polluting, will evolve (Brouwer et al. 2016). Similarly, the environmental impact of transport sector electrification necessitates assumptions about the future energy mix. Electric vehicles may be carbon-free on the road, but if they derive energy from highly polluting technologies such as coal, they can increase net emissions (Elshurafa and Peerbocus 2020). Furthermore, countries that heavily rely on natural gas and expect energy demand to increase must plan and budget for additional gas exploration, storage, and/or imports (Matar and Shabaneh 2020). Such cases exemplify how CEP studies relate to the wider macroeconomy.

Globally, we find the literature rich with CEP studies attempting to answer various questions using different analytical tools and methods (Gacitua et al. 2018). For example, using the General Algebraic Modeling System (GAMS) programming language, Heuberger et al. (2017) created a model for the United Kingdom's power system from 2015 to 2050 that considered endogenous technology cost learning curves. In another study, Pean, Pirouti, and Qadrdan (2016) assessed the role of interconnectors in balancing supply and demand in the French and British systems, using the commercially available software package PLEXOS. They concluded that interconnection will reduce overall operational costs, emissions, and wear-and-tear on gas power plants used to compensate for the intermittency of solar and wind technologies. Emodi et al. (2017), on the other hand, used the LEAP model to evaluate the future of Nigeria's energy mix under a range of assumptions and scenarios. The 'MARKet ALlocation,' or MARKAL, model is another popular platform for CEP studies. Victor, Nichols, and Zelek (2018), for example, applied MARKAL to the US context, and found that it is possible to achieve an 80% reduction in emissions below 2005 levels by 2050 through deploying available technologies. Other research has adopted the Wien Automatic System Planning (WASP) or Open Source Energy Modeling System (OSeMOSYS) platforms, such as Zeljko et al. (2020) and Riva et al. (2019), respectively. All the above mentioned platforms are generally considered common for CEP studies.

Although in many CEP applications the aim is to minimize expense, planners must frequently consider plausible or desired scenarios that carry higher costs. Reasons for this include emissions targets, creating employment, and the high uncertainty of future fuel prices (Bohlmann et al. 2019). For this reason, fundamental energy system transformations can be considered both cost- and policy-driven (Brouwer et al. 2016).

CEP studies differ from optimal dispatch studies, which focus in greater detail on operational variables and grid stability. Dispatch models utilize time resolutions that can go down to seconds and account for multiple operational factors, including types of operating reserves, ramping costs and rates, start-up costs, and start-up times, among others. CEP studies do not typically include such granularity (Buchholz, Gamst, and Pisinger 2019). This poses a challenge in terms of model tractability, hardware requirements, and solution times for models typically spanning 20-30 years or more. As a result, CEP modelers generally use coarse time resolutions and are selective about which variables to include. However, the growing complexity of future power systems due to storage and renewables creates an increasing need for greater detail in CEP studies (Maloney et al. 2020; Diaz, Inzunza, and Moreno 2019). Modelers must therefore strike a balance between model accuracy and manageability. For more information about CEP models and planning, please refer to the literature, including Koltsaklis and Dagoumas (2018), Babatunde, Munda, and Hamam (2019), and Dagoumas and Koltsaklis (2019).

2.3. Capacity expansion studies: Saudi focus

Although many CEP studies cover European countries and the U.S., only a few focus on Saudi Arabia. Matar, Echeverri, and Pierru (2016) assessed the economic feasibility of using coal in the Saudi energy mix and concluded that it would not be competitive due to the low administered prices of oil and gas. In another study, Matar et al. (2017) analyzed the effect of reforming fuel prices for the Kingdom's industrial sector. They found that a more efficient energy system, in which nuclear and renewable technologies produce 70% of electricity in 2032, could be realized if fuel prices are deregulated.

Groissböck and Pickl (2018), on the other hand, examined the future energy mix in Saudi Arabia under different fuel-price scenarios and concluded that certain scenarios could result in renewables satisfying nearly a third of energy needs by 2030. Finally, Matar and Shabaneh (2020) examined the viability of importing and/or storing gas in the Kingdom and how this would affect future power generation builds. Table 1 summarizes the above-mentioned CEP studies.

2. Review and Context

Table 1. Summary of CEP studies conducted for Saudi Arabia.

Reference	Motivation for the CEP study	How CEP was solved	Base year	Horizon
Matar, Echeverri, and Pierru 2016	Assess use of coal in power generation	GAMS: Linear program	2015	2030
Matar et al. 2017	Assess impact of reforming fuel prices for industrial sector	GAMS: Linear program	2015	2032
Groissböck and Pickl 2018	Assess impact of various fuel prices	OSeMOSYS	2015	2030
Matar and Shabaneh 2020	Assess impact of importing and/or storing gas	GAMS: Linear program	2015	2030
This work	Assess impact of retiring liquid fuels on renewable builds, emissions, and gas infrastructure	PLEXOS: Integer	2018	2040

Our study differs from previous research focused on the Kingdom in two significant ways. First, the four earlier papers cover time periods from 2015 to 2030 or 2032. This study, on the other hand, starts from 2018 and extends to 2040. Furthermore, it adopts an integer approach for the solution, which is more accurate than linear programming, but requires more memory and time to solve (Miao et al. 2021).

3. Scenario and Model Description

3.1. Scenarios considered

We model the impact of retiring liquid fuels from Saudi Arabia's power generation sector on emissions and the accompanying role of renewables under the following three scenarios, which are also summarized in Table 2 below.

A. Scenario 1 – Base case (BC): To provide a benchmark for comparison purposes, we assume that Saudi Arabia's energy mix continues to rely on liquid fuels for power generation. However, we do not allow any new liquid-based power plants to be built and restrict new plants to the following technologies: gas, PV, wind, concentrated solar power (CSP), nuclear, and battery storage. We also assume that fuel prices continue to be administered according to the current values (see Appendix A for the fuel prices used).

B. Scenario 2 – Liquid fuel retirement at administered low gas price (LRAP): Here, we gradually retire all liquid fuels (HFO, crude, and diesel) by 2030. To achieve this, we restrict the share of liquid fuels to a maximum of 40% in 2022, and linearly decrease this to 0% by 2030. We set the gas price to US$1.25 per million British thermal units (US$/MMBtu) throughout the planning period and apply no gas transportation constraints. The candidate-build technologies are identical to those in the BC scenario. Until liquid fuels are phased out in 2030, the current administered prices continue to apply.

C. Scenario 3 – Liquid fuel retirement at deregulated gas price (LRDP): This scenario repeats the previous one except for the gas price, which we set at US$1.25/MMBtu through 2025, after which it increases to US$3/MMBtu through 2040, in line with the U.S. Energy Information Administration's forecast (EIA 2020a). As in Scenario 2, we apply no gas transportation constraints.

Table 2. Summary of scenarios simulated.

Parameter	Scenarios considered in this paper		
	Scenario 1 - BC	**Scenario 2 - LRAP**	**Scenario 3 - LRDP**
Liquid fuels usage	Used until 2040	Retired by 2030	Retired by 2030
Liquid fuels price	Administered throughout the planning horizon (see Appendix A)		
Gas price	1.25 $/MMBtu	1.25 $/MMBtu	1.25 $/MMBtu during 2018-2025 3.00 $/MMBtu during 2026-2040
Candidate builds	Gas, nuclear, PV, wind, CSP, battery		

3.2. Building the model

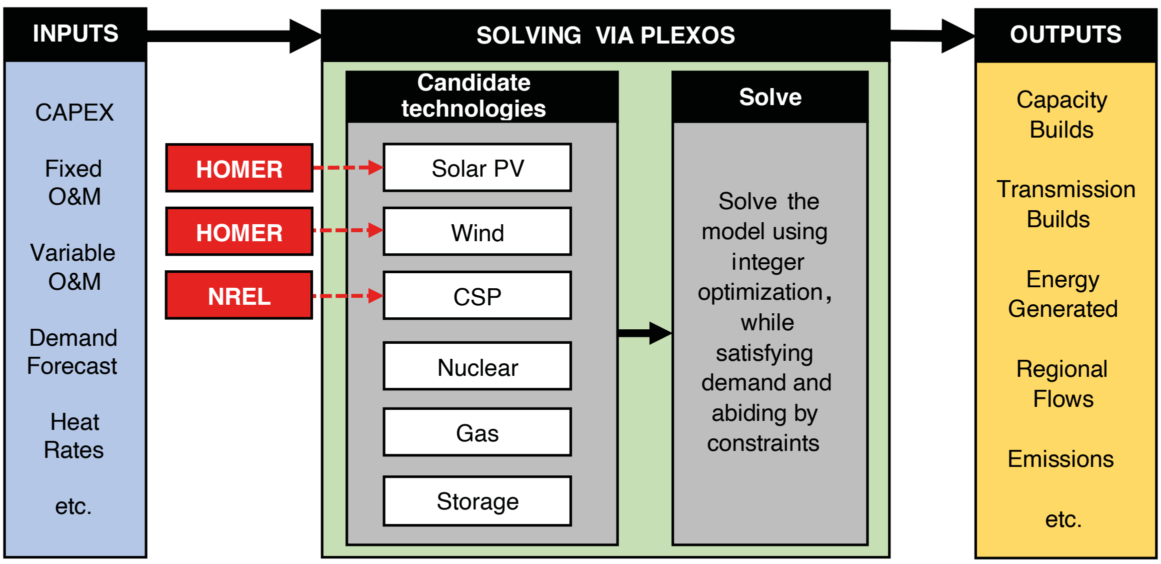
3.2.1. Overview of model

We constructed the model using PLEXOS and adopted integer optimization for solving. We set the base year as 2018 and extended the CEP analysis through 2040. We also segmented the Kingdom into six regions: eastern, central, western, southern, northeastern, and northwestern.

The model incorporates spinning reserves, capacity reserves, ramping rates, and ramping costs. Although these do not represent all available dispatch phenomena, they capture key operational parameters, especially given that renewables are expected to satisfy a considerable share of energy. They also strike a balance between the level of detail in describing the problem and the computational resources needed to run the model. We set spinning reserves to be at least 10% of load at any instant, and capacity reserves for each region to 15% of peak load in any given year (Reimers, Cole, and Frew 2019). The central region's peak load is currently higher than its available capacity reserves; accordingly, we assumed these will be met by 2025. No electricity flows between the Kingdom and other countries. We apply a discount rate of 5% throughout the model. Appendix A summarizes all capital costs, fixed operational and maintenance (O&M) costs, variable O&M costs, and other numerical parameters and assumptions.

Figure 1 illustrates the overall model structure by presenting key inputs and outputs. We soft-linked PLEXOS to two other software packages, HOMER and the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM). We utilized the commercially available software HOMER to obtain the generation profiles of solar PV and wind technologies. Similarly, we acquired the concentrated solar power (CSP) output profile from NREL SAM.

Figure 1. A conceptual schematic of the model.



Note: The model was built and solved in PLEXOS. The red dashed arrows represent soft-links between PLEXOS and two software packages, HOMER and NREL SAM.

3.2.2. Demand

In any CEP study, demand trajectories represent critical inputs. Saudi Arabia's electricity demand patterns witnessed structural changes in recent years as the government implemented efficiency measures and initiated two rounds of pricing reforms in 2016 and 2018. These developments curbed the country's fast-growing power demand, which has flattened since 2016.

We projected demand based on the work conducted by Soummane and Ghersi (2021), which formulates a dynamic computable general equilibrium (CGE) model for Saudi Arabia to project sectoral electricity demand. This CGE model, calibrated for 2013, captures the Kingdom's key economic features, such as administered electricity prices, and follows a dynamic calibration allowing it to replicate observed electricity demand between 2014 and 2018 into the future. Explicitly, this resulted in an average annual growth rate of around 1.6% through 2040, translating to total consumption and peak load of 520 TWh and 90 GW, respectively, in 2040. The latter represents a 20-year increase in peak capacity of 30 GW.

3.2.3. Solar PV

Solar PV generation assumed the use of fixed-tilt modules with 16% efficiency. The temperature loss coefficient was 0.5% per degrees Celsius (°C), and the nominal operating cell temperature was 47°C. We set overall PV system losses at 15%, and assumed no annual degradation of the modules. These assumptions and parameters, which appropriately describe the performance of physical PV systems (Elshurafa et al. 2019), were used in the software package HOMER Pro and the output profile, in turn, as an input for the PLEXOS model. In addition, we restrict the model to building no more than 4 GW of PV capacity per year.

Because PV is intermittent and does not provide energy at night, installed PV capacity cannot be considered firm (i.e., able to meet demand at any instant). However, it is reasonable to include a fraction of installed PV capacity as firm capacity during the daytime. We take the average power profile of PV for the hours from 8am to 3pm for the whole year and find that the average power capacity is 25% of the total capacity. This simplified calculation is based on work by Frew et al. (2017). We take a conservative stance and assume that PV contributes to firm capacity between 8 am to 3 pm, but only with 15% of its total installed capacity (Soria et al. 2016).

3.2.4. Wind

Wind generation assumed a hub height of 80 meters (m) (Ashrafi et al. 2018) and applies the power output profile obtained from HOMER for the corresponding region. As with PV, we restrict annual wind builds to 4 GW per year. The firm capacity for wind (Tuohy and O'Malley 2011), however, was not treated the same way as PV: wind contributes by 15% to firm capacity throughout the day (Brouwer et al. 2014).

3.2.5. CSP

To calculate the output of a CSP plant, which we assumed to be a parabolic trough system, we obtained publicly available direct normal irradiance (DNI) data from the NREL.[1] The hourly data was fed into the NREL SAM CSP module to create

[1] Available at: https://www.nrel.gov/grid/solar-resource/saudi-arabia.html

an electrical equivalent profile for the CSP plant. Specifically, the NREL SAM model converts the irradiance data to thermal energy and then to net electrical output, while accounting for the losses that occur through these processes. As will be shown, the model does not choose to build any CSP due to its high capital cost, even after testing for firm capacity values ranging from 50% to 100% (Soria et al. 2016).

The CSP plant comprises three components: the solar field (which generates the thermal energy), the storage component, and the power generation block. To represent this in PLEXOS, we adopt the same methodology previously reported by Denholm et al. (2013), which links a power generator to a storage unit. Every hour, the model can provide energy from irradiation, store energy, or dispense stored energy, subject to the capacity of the storage unit. We use a solar multiple of 1.7 in the calculations, set CSP plants to be built in 1 GW increments, and assume that a CSP plant can provide eight hours of storage.

3.2.6. Nuclear

The model can add nuclear power plants in integer multiples of 1 GW. We also restrict the model to build nuclear plants in the eastern province only, as the western region will be hosting several new touristic and entertainment cities. The model assumes a heat rate of 10,400 Btu/kWh. The capital expenditure for nuclear contains only a small reduction over the years due to the increased system complexity and increasingly stringent safety regulations (Grubler 2010, Heuberger et al. 2017). We set the fuel cost here to US$0.85/MMBtu (Lazard 2019).

3.2.7. Natural Gas

For power generation by natural gas, we considered two types of turbines: single cycle (SC) turbines and combined cycle (CC) turbines. For SC turbines, we set the heat rate to 9,000 Btu/kWh with a capacity of 200 megawatts (MW); for CC turbines, we assumed 6,000 Btu/kWh and 400 MW, respectively. We obtained (rounded) values for the heat rate and capacity from the specification sheets of new gas turbines for Siemens and GE. Note also that we consider the ramping rates and costs for each type of turbine. We assumed capital costs of US$1,000/kW for CC turbines and US$700/kW for SC turbines (EIA 2020b). Because of considerable renewable penetration, we built ramping rates and costs into the model. Based on the specification sheets, we applied ramping rates of 20% and 5% of capacity per minute for SC and CC turbines, respectively. We also set ramping costs to US$0.92/ΔMW for SC turbines and US$0.58/ΔMW for CC turbines (Van den Bergh and Delarue 2015).

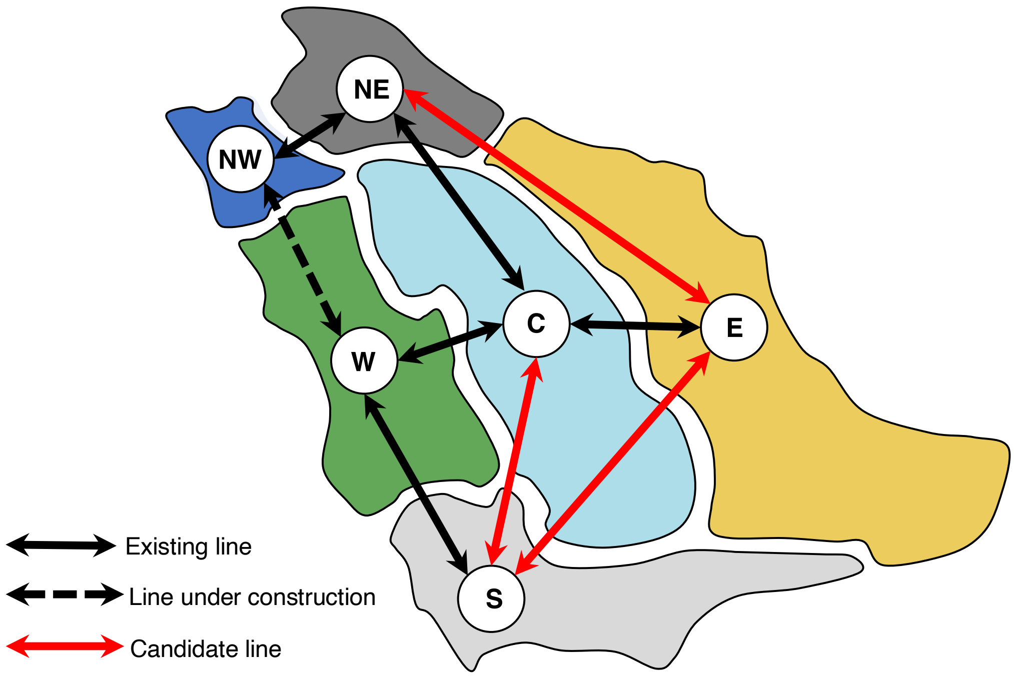
3.2.8. Battery storage

The model includes battery storage devices rated for 100 MW, with four hours (400 megawatthours [MWh]) worth of storage capacity, which fully contributes to firm capacity. We set both charging and discharging efficiencies at 95%, which brings the overall roundtrip efficiency to 90% (Cebulla, Naegler, and Pohl 2017). The batteries could reach a minimum state of charge of no less than 25%. Given the harsh temperatures of Saudi Arabia, we assumed a seven-year technical life for the batteries (Smith et al. 2017).

3.2.9. Transmission

Figure 2 shows a map of Saudi Arabia depicting the six regions considered in the model, each represented by a node. Solid black lines depict existing transmission lines, while the dashed black line represents the planned line connecting the western and northwestern regions, which is set to come online in a few years with a capacity of 3 GW, according to various recent news reports. The red lines show candidate lines that would be built in the model if deemed economic. We assume these to have a total capacity of 1.5 GW. We assume the lead time to build transmission lines to be four years (Lumbreras and Ramos 2016).

Figure 2. The six regions used in the model and transmission lines connecting them (not drawn to scale).



Note: C – Central; E – Eastern; NE – Northeastern; NW – Northwestern; S – Southern; W – Western.

4. Results and Discussion

As mentioned earlier, the model utilizes integer optimization, which is more accurate than linear programming but requires additional computational resources and time. The model being solved is relatively large, as it extends to 2040 and maintains the temporal characteristics of the problem. The latter is especially important with renewables penetrating the power system. As with all modeling exercises, one should strike a reasonable balance between accuracy and solution time. Using a fitted chronology and a relatively fine time resolution, we conducted many test runs on a virtual machine (possessing 64 gigabytes of RAM and 16 cores) to arrive at a reasonable model setting. Solution times ranged between 30 and 60 hours depending on the constraints, solver, and solution settings. Other simulations were terminated when a solution was not achieved after three days. Alternatively, a solution that used a sampled chronology with 10 sample days per year reduced the solution time to less than six hours while keeping the results comparable. To provide a numerical example, total emissions for the BC scenario solved using the fitted and sampled chronologies were within 2% of each other. Hence, all results shown below adopted a sampled chronology with 10 sample days per year, and the solver used was CPLEX.

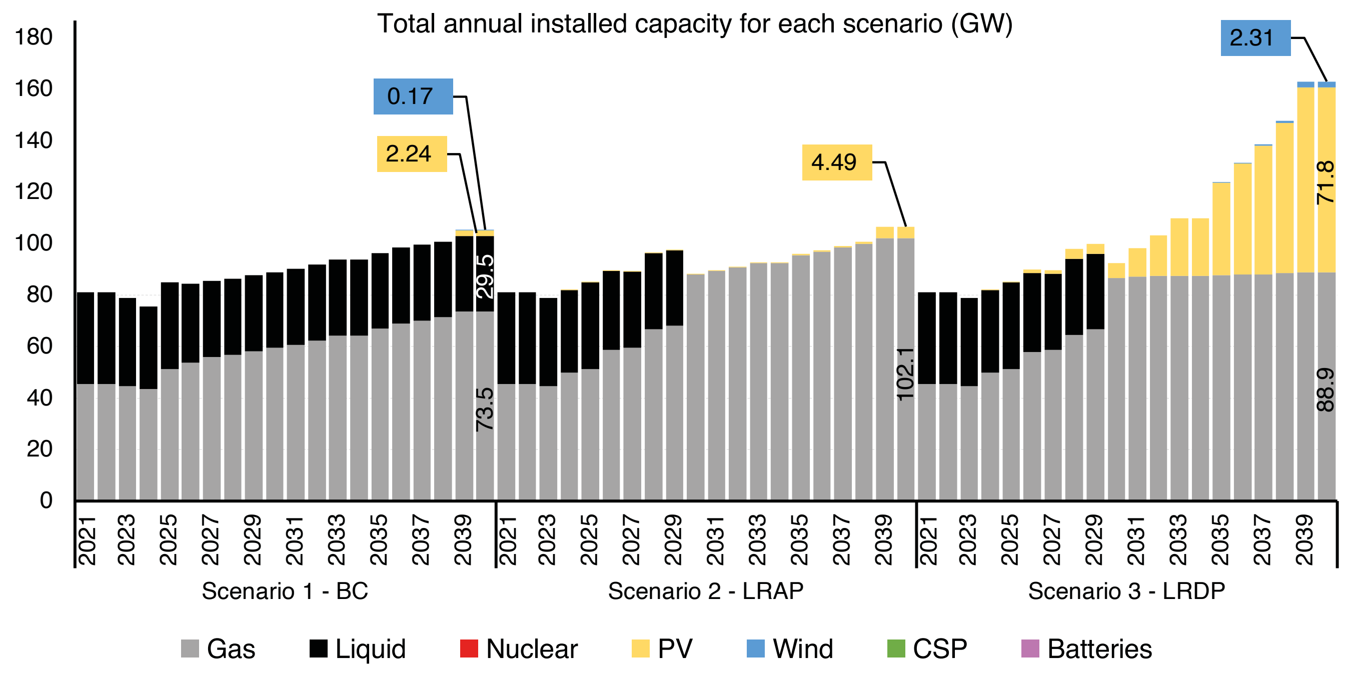
4.1. Generation builds and electricity shares

The elimination of liquid fuels from the power sector leaves only gas-fired generation as the primary source of firm capacity, along with a limited amount from renewables, as described earlier. As a result, we can expect that the gas generation capacity will be around 103 GW (including the 15% reserve margin), because the peak load would reach 90 GW in 2040. Figure 3 shows the installed capacities for all three scenarios. As expected, Scenario 3 (LRDP) includes significant renewable deployment given the high gas price, with a total PV capacity of over 71 GW by 2040. On the other hand, renewables feature much less prominently in scenarios 1 and 2. Further, the LRDP scenario model builds less gas-fired capacity than required for peak load, with PV (and a small amount of wind) proving the remainder. In 2040, PV accounts for 44% of total available capacity in the LRDP scenario, around 71 GW, distributed as follows: 16.2 GW in the eastern region, 25.9 GW in the central region, 22.7 GW in the western region, 2.2 GW in the southern region, 1.4 GW in the north eastern region, and 3.2 GW in the northwestern region.

We also note that in all three scenarios, the model does not build CSP or nuclear generation, and postulate two main reasons for this. First, both technologies have much higher capital costs than solar and wind. Second, because the model is run in integer mode, plants with less than 1 GW are not possible, increasing the upfront capital required. As a result, the model resorts to the other available candidate technologies.

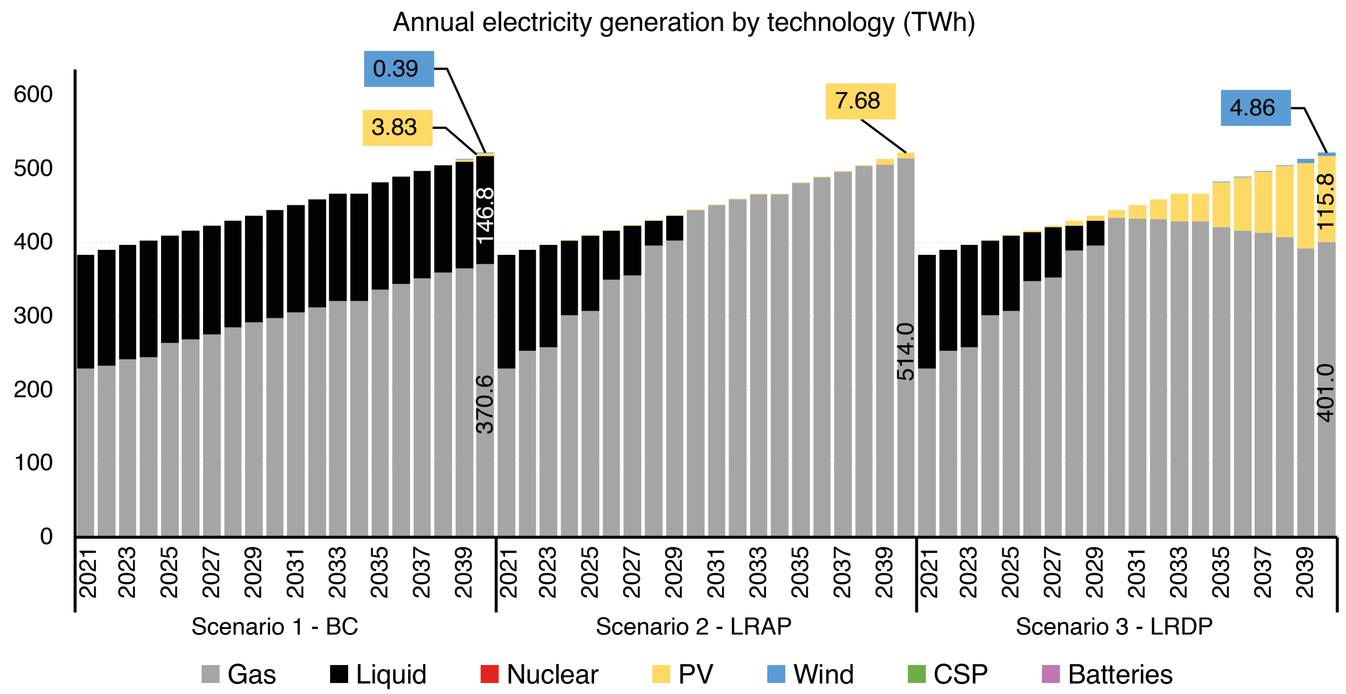
In Figure 3, in the BC scenario, liquid-based generation continues to exist throughout the planning horizon. However, the installed capacity of liquid-based generation in the LRAP and LRDP scenarios is zero from 2030 onwards. Note that, although the capacity of these liquid-based generators is relatively large until 2030, they are not fully utilized due to the fuel retirement constraints imposed (refer to Section 3.1 for details). Hence, Figure 4 reports the more indicative electricity shares of each fuel.

Figure 3. Total available generation capacity show until 2040.



Note: Results for Scenario 1 (BC) are shown on the left, results for Scenario 2 (LRAP) are shown in the middle, and results for Scenario 3 are shown on the right. The total installed capacity is explicitly indicated for the year 2040 only.

Figure 4. The electricity share based on fuel for all three scenarios.



Note: Both the LRAP and LRDP scenarios show that liquids gradually reduce their shares until they are fully retired in 2030.

Figure 4 shows how electricity demand met by liquid-based generators gradually decreases until their removal in 2030, despite a relatively constant generation capacity. PV provides negligible amounts of energy in the first two scenarios, but around 22% of total demand in 2040 in the LRDP scenario. The model does not consider retrofitting liquid-based generation for three main reasons: (1) we do not have data regarding which plants are retrofittable, (2) we do not have the retrofitting costs that would apply to each plant, (3) we do not know what the new heat rates would be after retrofitting. Although we could make reasonable assumptions, the uncertainty would be too high.

4.2. Transmission Builds

The model simultaneously considers both generation and transmission capacity builds in the optimization. Before discussing the results of any candidate transmission builds, we note that the line currently under construction and planned to come online in 2026 between the western and northwestern regions will have a significant impact on all scenarios.

The BC and LRAP scenarios see no transmission builds. However, the LRDP scenario builds a line connecting the eastern and southern regions that comes online in the year 2029. One reasonable explanation for this decision is the heavy reliance of the southern region on liquid fuels. Rather than building new generation in the southern region, the model sees more value in it being connected to the eastern region, which possesses significant gas capacity.

Moreover, none of the scenarios build any battery storage; the model prefers more interconnection within the Kingdom than battery deployment. This reflects an important insight that does not usually receive adequate attention. Although storage is considered a technology that complements the intermittency of renewables (He et al. 2020), other options are also available and may prove less costly.

From a practical perspective, the Kingdom is home to the Oroug-Bani-M’aradh Wildlife Sanctuary, situated between the southern and central regions. The eastern-southern transmission line mentioned above is financially viable according to the model, but obtaining the right of way permits through this sanctuary may prove to be problematic. Furthermore, we note that the terrain in the southern region is primarily mountainous. As a result, constructing transmission lines (and finding appropriate sites for PV deployment) can be challenging.

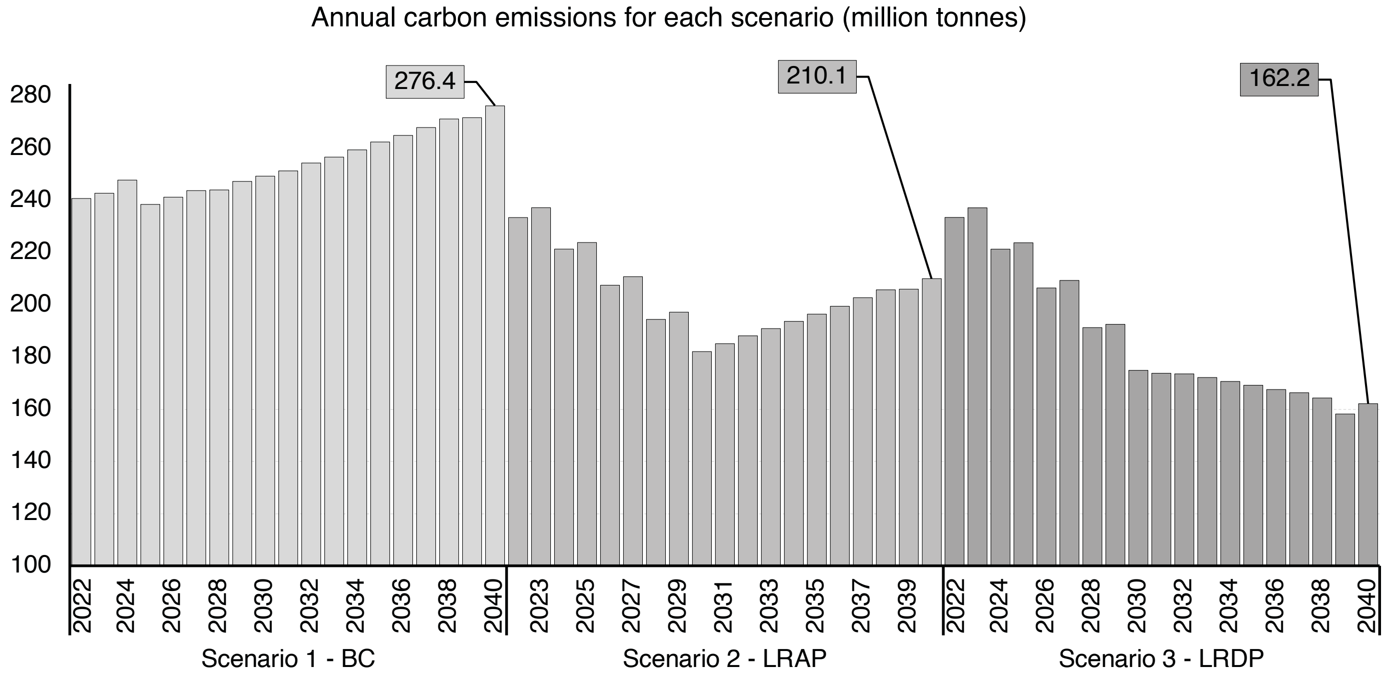
4.3. Emissions

Retiring liquid fuels will decrease the electricity sector’s carbon dioxide (CO_2) emissions. Not only are renewables carbon-free, but gas-based generation is less polluting than its liquid-fuel counterparts. In Figure 5, we show the annual emissions for all three scenarios.

In the BC scenario, emissions increase throughout but decelerate in later years due to new, high efficiency gas builds: in 2040, annual emissions would total around 276 million tonnes. In the LRAP scenario, emissions gradually decrease until 2030 as liquid fuels are phased out, and then increase again until they reach 209 million tonnes in 2040. In the LRDP scenario, in which the gas price (almost) follows the Henry Hub index starting in 2026, emissions drop to around 175 million tonnes in 2030, and then decrease at a slower rate to 2040, despite the increase in electricity demand. We attribute this mainly to the significant capacity of renewables deployed.

As of 2018, Saudi Arabia's emissions intensity (Pan et al. 2019) was about 0.8 kilograms (kg) of CO_2/kWh (Wogan, Carey, and Cooke 2019). However, the emissions intensity for the BC, LRAP, and LRDP scenarios would be 0.53 kg·CO_2/kWh, 0.4 kg·CO_2/kWh, and 0.31 kg·CO_2/kWh, respectively.

Figure 5. Annual carbon emissions for each scenario.



Note: As expected, the LRDP scenario reduces emissions the most. In all scenarios, however, the emission intensity is reduced.

4.4. Gas offtake and cost considerations

The model design takes into account several key factors impacting gas offtake and cost. First, gas consumption in Saudi Arabia varies significantly during the year, rising sharply in summer months due to intensified electricity demand from the increased use of air conditioning.

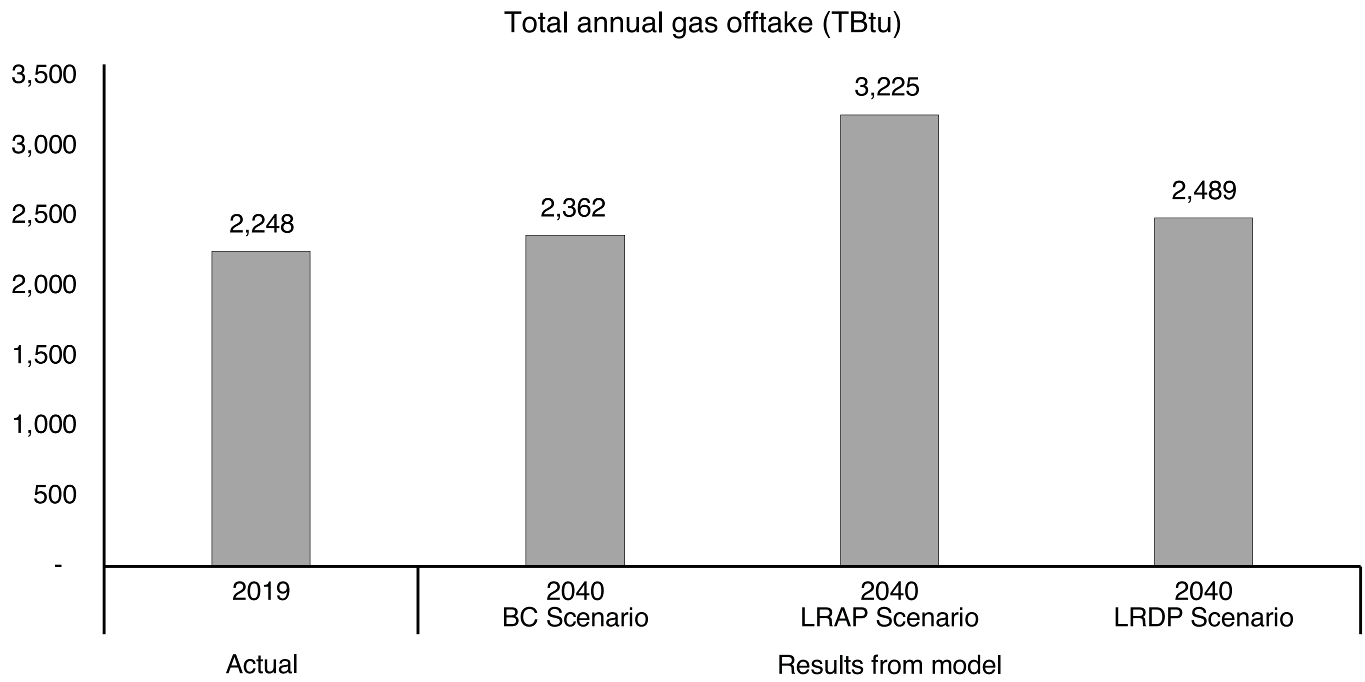
Second, the Kingdom's industrial sector, in particular its petrochemical industry, requires gas for operation and production. From the oil-and-gas-rich eastern region, the master gas system allows gas to be transported to the central, western, and southern regions. Currently, however, there are some transport capacity constraints for gas reaching the western region. Exact daily gas transport caps (whether in terms of pipeline constraints or gas availability/allocation) are confidential. Saudi Arabia did announce, however, that it intends to double its gas production by 2027 and to also expand the pipeline connecting the eastern and western regions (Matar and Shabaneh 2020).

4. Results and Discussion

Considering all of this, the model contains no gas constraints: whether overall supply constraints for the entire sector or gas transport constraints between the regions during different seasons. This unconstrained setup of the model lends insight into the additional magnitude of gas that would be required, if any, to fully gasify the Kingdom's power system.

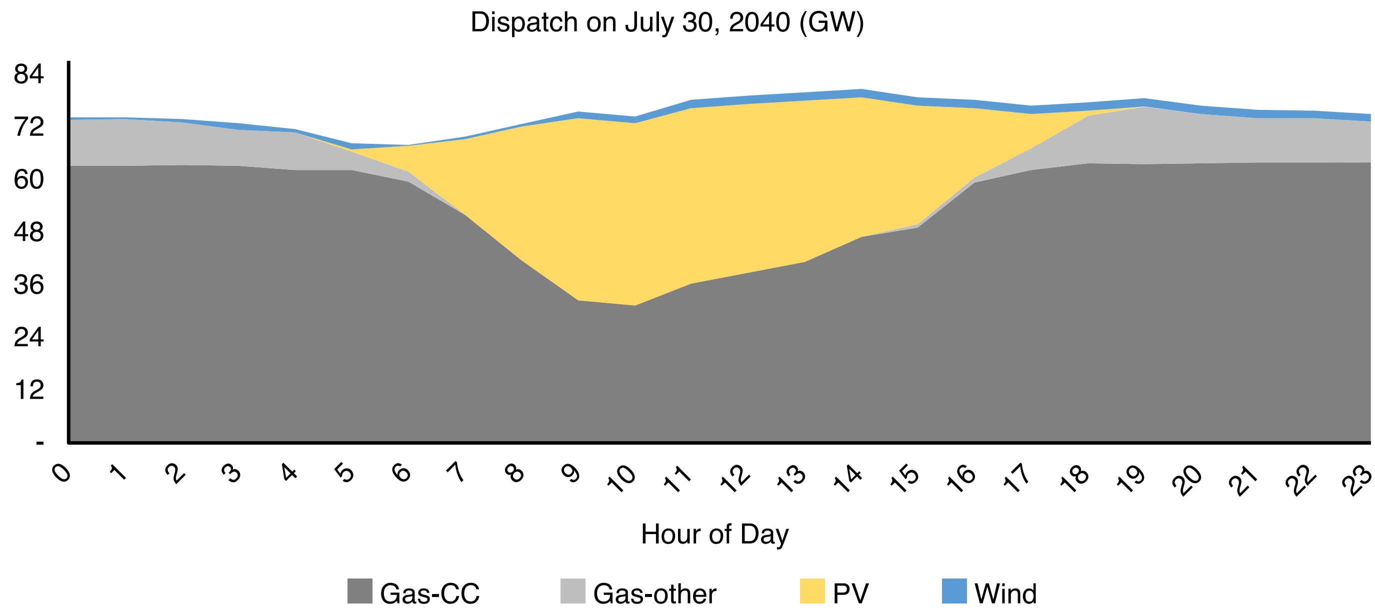
Figure 6 shows the annual gas offtake required in all three scenarios and compares it with the actual gas offtake in 2019. In the BC scenario, gas offtake increases by about 110 trillion Btu (TBtu), or 5% of 2019 levels. We attribute the comparatively small rise in gas demand, despite the considerable increase in electricity demand, mainly to the deployment of new, highly efficient gas turbines. In the LRAP scenario, in which gas prices remain fixed, we see that the gas offtake in 2040 increases significantly to reach 3,216 TBtu. Here, gas is satisfying nearly all demand and compensating for the retired liquid fuels. In the LRDP scenario, we see that total gas offtake remains near 2019 levels, which is due to the combination of new, highly efficient gas turbines and the deployment of nearly 72 GW of solar PV.

Figure 6. The total annual gas offtake for 2019 compared with model results for all three scenarios in 2040.



It is important to show a sample of daily gas offtake magnitudes in the LRDP scenario in particular because, as mentioned, there are (currently) daily cap limits on gas supply within the Kingdom. Figure 7 shows the dispatch for a summer day in 2040 totaling around 9 TBtu. As expected, we observe that PV contributes significantly to meeting demand during the daytime. We also note that as the PV contribution starts to decrease around midday, gas-fired generation ramps up to compensate, and we observe the well-known ‘duck curve’ (Wong et al. 2020). Furthermore, we note that while at the country level, the LRDP scenario shows that Saudi Arabia will require only about as much gas in 2040 as it did in 2019, gas requirements vary considerably at the regional level.

Figure 7. The dispatch of the system in the LRDP scenario on a summer’s day in 2040.



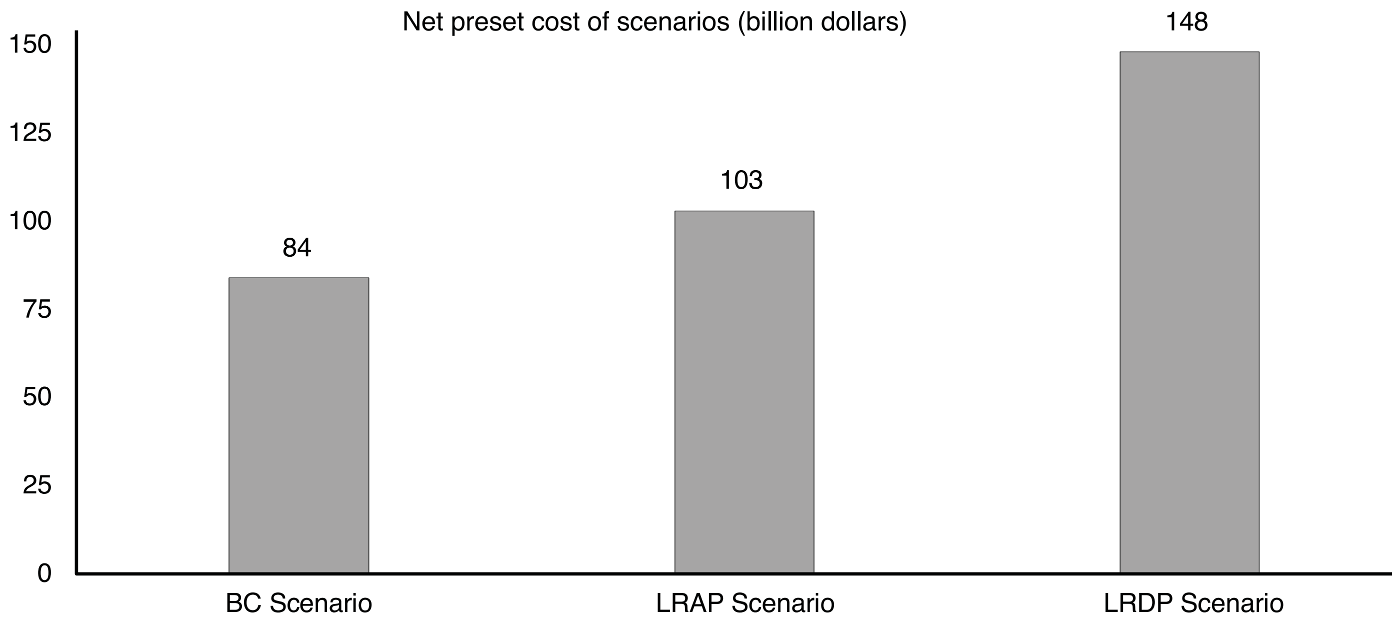
Note: The component ‘gas-other’ represents single-cycle and steam turbines.

We also compare the gas offtake in 2019 in the western region with the model results in 2040. As mentioned above, the western region currently relies heavily on liquid fuels, and there are plans to expand the eastern-western gas pipeline. In 2019, the western region consumed only 136 TBtu of gas, while the model finds it would require approximately 862 TBtu and 614 TBtu of gas in the LRAP and LRDP scenarios, respectively, to meet electricity demand in 2040, highlighting the scale of investment in gas infrastructure needed for the Kingdom to successfully retire liquid fuels. This could be done through expanding the master gas system, resorting to gas storage via aquifers or depleted oil/gas reservoirs, importing gas, or a combination thereof. Assessing which option is most efficient stands out as a valuable area for future study.

Undoubtedly, the three policy scenarios considered in this study would be realized at different costs. The reader is also reminded that policy alternatives or choices are not strictly driven by economics, as discussed in detail in Section 2. Figure 8 presents the net preset cost (over 20 years) of the three scenarios. The BC scenario, which uses liquid-based generators throughout the planning horizon, is the least costly option, while the LRDP scenario is the costliest option. Of course, the additional costs of the LRAP and LRDP scenarios result in considerable reductions in carbon emissions, as noted in Section 4.3, of 25% and 41%, respectively versus the BC scenario in 2040.

Figure 8 summarizes the costs immediately related to power generation (fuel, transmission builds, generation builds, ramping, etc.) but excludes gas exploration, gas pipelines expansion, and so forth. However, recall that the LRAP scenario requires significantly more gas offtake than the BC scenario. This would likely necessitate additional gas supply and an expansion of the gas network. The LRDP scenario, on the other hand, requires no additional gas supply but requires an expansion of the gas network only. With that in mind, the LRAP scenario may end up being the costliest option, including the necessary gas exploration and network expansion costs.

Figure 8. Net preset costs of the scenarios studied.



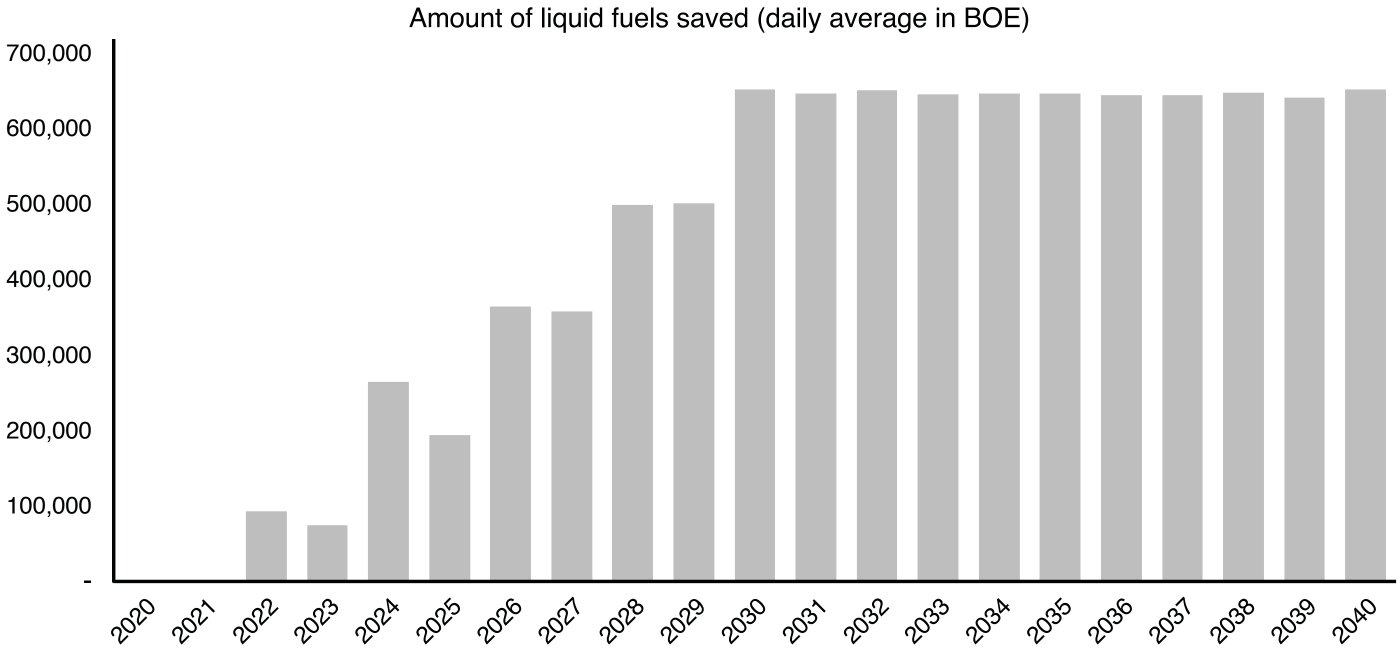
Note: These costs do not include the costs of gas exploration or gas infrastructure expansion. The discount rate used was 5%.

The additional costs of the LRAP and LRDP scenarios were not borne in vain. As detailed in section 4.3, the LRAP and LRDP scenarios both result in a considerable reduction in emissions compared with the BC scenario. By 2040, the LRAP and LRDP scenarios result in a 25% and 41% emission reduction compared with BC.

We can interpret the net present value costs in Figure 8 in several ways. One is to quantify what equivalent carbon price policy would result in the same amount of carbon emissions reduction and/or renewable deployment. Explicitly, an equivalent carbon tax (in 2021 US$) can be calculated by taking the ratio of the difference in net present costs to the difference in overall emissions; this results in approximately US$20 and US$50 per tonne for LRAP and LRDP, respectively. The same values can be seen as the cost of abatement that the government must bear to reduce emissions in both scenarios.

Figure 8 can also be contextualized based on the returns from oil that should be attained to justify, from a strictly financial viewpoint, retiring liquid fuel from the power sector. In other words, the planned investments should have a net present value greater than the difference between the BC and the other scenarios. Figure 9 provides an estimate of the oil saved (in barrels of oil equivalent, BOE) for the entire planning horizon.

Figure 9. The average daily oil savings, according to the model.



Note: The results above were calculated as the difference between the liquid fuel offtake in the BAU scenario and the liquid fuel offtake in the LRAP scenario. Note how the saved oil stabilizes at about 650,000 BOE per day from 2030 onwards.

Based on the model results, there would be, on an average daily basis, around 650,000 BOE avoided from 2030 onwards. This result appears realistic, falling roughly within the same range of current consumption levels of liquid fuels in the Kingdom.

From this, a hurdle rate can be deduced to ensure that the saved barrel of oil, which is to be exported to the international market, used as feedstock in appropriate industries, or otherwise, brings about the minimum required returns.

5. Conclusion and Summary of Scenarios

Using a power model, we simulated future scenarios to provide insight on financial, emissions, capacity, and other implications that would stem from eliminating liquid fuels from Saudi Arabia's electricity sector. This study distinguishes itself from previous Saudi-focused ones by extending the analysis horizon until 2040, using an integer approach for the optimization, and dividing the Kingdom into six regions rather than four regions. Table 3 summarizes several key results from the modeling conducted in this paper.

Table 3. Key results from the model for all three scenarios.

Metric	**Scenario 1: BC**	**Scenario 2: LRAP**	**Scenario 3: LRDP**
Total gas offtake in 2040 (TBtu)	2,362	3,225	2,489
Total gas offtake in the western region in 2040* (TBtu)	195	862	614
Annual emissions in 2040 (million tonnes)	276	210	162
Emissions intensity in 2040 (kg·CO_2/kWh)	0.53	0.40	0.31
Total installed capacity in 2040 (GW)	105.4	106.6	163
PV installed capacity in 2040 (GW)	2.2	4.5	71.8

Note: Base case (BC), liquid retirement with administered gas price (LRAP), and liquid retirement with deregulated gas price (LRDP). Consumption and peak load reach 520 TWH and 90 GW, respectively, in 2040.

** includes western and north western regions.*

At current administered fossil fuel prices, we find that it is difficult for alternative technologies to compete, despite their significant cost reductions and technological advancement. Moreover, solar PV is the only alternative technology that can be deployed effectively at scale in the context of this paper (i.e., liquids retirement). The high gas price scenario promotes PV deployment and results in emissions reduction but at a significant cost, which can be interpreted as an emissions abatement cost (Wang et al. 2020). It also serves as a guide to how saved barrels of oil could be invested.

We also find that raising, or deregulating gas prices would promote the redistribution of gas demand within the regions, as shown in Table 2. In 2040, the western region would require nearly three times more gas in the LRDP scenario than in the BC scenario. However, overall, both scenarios have comparable total gas demand. In other words, even for the LRDP scenario, investments in domestic gas transport between regions may be sufficient, avoiding the need to increase the power sector's gas supply. This distinction is an important observation that resulted from the numerical analysis conducted in this paper.

Storage technology can address the inherent intermittency of renewables, a recurring theme in the literature. However, as shown in this paper, better interconnection between network nodes may offer a more economic route to the same end. Our analysis found that storage would not be cost-effective in the scenarios examined, even in LRDP, which deploys a large amount of PV. This result should caution policymakers and investors against immediately assuming that the storage-PV symbiosis is the best or most natural route without considering the load profile, flexibility of available generation, and better interconnection potential in a given scenario.

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Appendix A

Table A1. The capital costs for the candidate technologies used in the model throughout the solution horizon. All costs included below are in United States dollars per kilowatt (US$/kW).

Year	Technology				
	PV	CSP	Wind	Nuclear	Storage
2021	773	3,669	1,159	6,553	1,100
2022	736	3,616	1,139	6,506	1,005
2023	703	3,563	1,120	6,451	918
2024	674	3,511	1,100	6,414	840
2025	646	3,460	1,080	6,396	760
2026	626	3,409	1,064	6,376	750
2027	607	3,360	1,046	6,353	708
2028	589	3,311	1,028	6,322	678
2029	572	3,263	1,010	6,280	650
2030	555	3,215	992	6,246	640
2031	538	3,168	974	6,213	620
2032	522	3,211	961	6,177	600
2033	508	3,077	942	6,143	586
2034	493	3,032	927	6,114	571
2035	479	2,988	912	6,077	560
2036	466	2,944	896	6,043	549
2037	454	2,901	881	6,008	538
2038	442	2,859	866	5,976	528
2039	431	2,817	850	5,940	520
2040	419	2,776	833	5,906	518

Sources: Data obtained from BNEF as average values for global installations; CSP capital expenditure data collected from Sullivan et al. (2015).

Note: PV=solar photovoltaic, CSP=concentrated solar power.

Appendix A

Table A2. Lead time and lifetime, in years, for candidate technologies.

Technology	Lead time	Lifetime
PV	2	25
CSP	3	30
Wind	2	25
Nuclear	10	50
Battery storage	3	7
Gas – combined cycle	2	35
Gas – single cycle	2	20

Sources: NRECA (2019), Smith et al. (2017), Matar and Anwer (2017), and Matar et al. (2017).

Table A3. Fixed and variable cost assumptions used in the model.

Technology	Fixed costs (US$/kW/year)	Non-fuel variable cost (US$/MWh)
PV	10	-
CSP	50	3.2
Wind	20	-
Nuclear	110	3.5
Storage	20	-
CC gas	12	3.5
SC gas	10	6

Notes: MWh=megawatthours.

Sources: Lazard (2019), IRENA (2019; 2020), Groissböck and Pickl (2018), Matar and Anwer (2017), Sullivan et al. (2015).

Table A4. Carbon emission factors of fuels and fuel prices used in the model.

Technology	Emission factors (lb/MMBtu)[1]	Fuel Price (US$/MMBtu)
Gas[2]	130.2	1.250
Crude oil	170.8	1.144
Heavy fuel oil	189.4	0.600
Diesel	172.4	2.410

Notes: lb=pound, MMBtu=million British thermal units.

[1] The emission factors vary in the literature by a few percent; [2] This gas price was used in Scenarios 1 and 2. However, in Scenario 3, the gas price increased to US$3.00/MMBtu as of 2026.

Endnotes

Endnotes

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Amro is a Research Fellow at KAPSARC with nearly 20 years of experience in the fields of energy and technology in three continents. His research interests lie in renewable energy policy, power systems modeling, and hybrid microgrid design and optimization. He has led and executed several national modeling initiatives both on distributed- and utility-scale projects. Credited with 40+ papers and several patents, Amro holds a Ph.D. in electrical engineering and an MBA in finance.

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About the Project

This project assesses the impacts of retiring liquid fuels from the Saudi power sector and the associated emission implications. Our research stems from the government’s recent announcements that the Kingdom will fully rely on gas and renewables in the future for its power needs.

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