Economic Impact of Integrating Distributed Renewable Energy Resources Through Virtual Power Plants

BY

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Dedicated to my

parents, bother and sisters for their never-ending prayers and encouragement,

my wife for her support and always being there for me to hone my determination, and

my friends and clleagues who inspired my perseverance and commitment

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Abstract

In light of ongoing efforts in the Kingdom of Saudi Arabia (KSA) to introduce renewable energy resources, this study aims to explore the economic feasibility of integrating such energy resources as distributed generations (DG), which is coupled with the demand centers. The DGs are being built by the electricity end-users pursuing the management of their energy cost, by bringing in-house generation. Those DGs and their associated demands are then aggregated to form virtual power plants (VPP) so that they have visibility to the grid and commercialize any excess energy they produce from their DGs. The study first considers a standard size of VPPs as a test bench to be deployed in different areas across KSA.

The VPPs simulation results from PLEXOS software are analyzed to measure their financial benefits and draw a conclusion of which of KSA's regions are represent the most fertile ground for VPPs of PV systems. For this purpose, a set of scenarios was considered to reflect different fuel pricing schemes and different load profiles (residential vs. industrial). The study was then extended to be applied to some of the small scale renewables energy projects announced by the Ministry of Energy (MoE) to be developed in some predefined locations of KSA.

ملخص الرسالة

في ضوء الجهود التي تبذلها المملكة العربية السعودية و الرامية إلى تبني مصادر الطاقة المتجددة كمُكوّن أساس لمزيج الطاقة بالمملكة، ضمن إطار رؤية المملكة 2030، تهدف هذه الرسالة إلى دراسة الجدوى الاقتصادية من بناء مراكز لمصادر الطاقة المتجددة موزعة بجانب مراكز الأحمال. إن بناء مراكز انتاج الطاقة المتجددة من قبل المستخدمين النهائيين للكهرباء يعتبر هنا كوسيلة لإدارة تكلفة الطاقة بواسطة توليد الكهرباء الذاتي. يتم جمع مراكز التوليد الذاتي والاستهلاك المرتبط بها لتشكيل ما يُعرف بمحطات طاقة افتراضية (Virtual Power Plant) ، مما يمنحهم القدرة على تسويق أي طاقة مُنتجة و فائضة عن حاجة مراكز الأحمال إلى الشبكة. في بداية الأمر، ستعتمد الدراسة حجم قياسي مُوحّد لمحطات طاقة افتراضية كمنصة اختبار يتم توزيعها في مناطق مختلفة من المملكة العربية السعودية.

في هذه الدراسة، يتم تحليل نتائج محاكاة تشغيل محطات الطاقة الافتراضية لقياس الفائدة الاقتصادية من إنشاء محطات توليد كهروضوئية، بناءً على تلك النتائج، يتم التوصل إلى استنتاجات حول أي من مناطق المملكة العربية السعودية هي الأكثر ملائمة من الجانب الاقتصادي لبناء أنظمة كهروضوئية ضمن محطات التوليد الافتراضية. تم في هذا البحث أخذ مجموعة من السيناريوهات التي تعكس تسعيرات مختلفة للوقود و خصائص الأحمال المختلفة (السكنية و الصناعية) بعين الاعتبار. ثم تم توسيع الدراسة لتطبيقها على بعض مشاريع الطاقة المتجددة الصغيرة التي أعلنت عنها وزارة الطاقة والتي سيتم تطويرها في بعض المواقع المحددة مسبقًا في المملكة العربية السعودية.

Chapter 1: Introduction

As part of Saudi Vision 2030, which aims for economic reform, the Kingdom of Saudi Arabia (KSA) has embarked on transformational plans and initiatives to enhance the performance of the electricity sector, being a pivotal enabler for the economy. Among the initiatives that pursue the improvement of the electricity sector are the privatization of the sector and the introduction of renewable energy resources. The former contributes to elevating the governance perspective and the cost efficiency by promoting competitiveness, while the latter has a potential value creation to KSA's economy from fuel perspective besides the environmental and strategic attributes. The energy generated from renewable energy resources will reduce the fossil fuel burning in the power plants, which avails an opportunity to export more fuel at prices higher than the domestic subsidized fuel prices.

To the extent of the introduction of renewable energy resources, KSA has set an ambitious target of installing 58.7 GW of renewables capacity by the year 2030. While KSA's economy is expected to yield promising benefits from this initiative, multiple key aspects need to be addressed to maximize the social welfare. For instance, it is imperative to study the economic impact of bringing these resources on the investors as well as the electricity end-users. For the investors to deploy capitals on building such projects, they look for market environments that allow them to make decent returns on their investment. Likewise, the end-users, be it households or industries, always fetch for ways and means by which they can manage their electricity bills. Accordingly, it is ideal to have an equilibrium between the attractive return made by the investor, which can be achieved via higher electricity tariff, and managing the electricity bill of the customer.

The current domestic fuel prices, which are heavily subsidized in KSA, and the cost of renewables technologies represent a challenge that confronts integrating the renewables to the KSA power system. Since the fuel prices are relatively low, the electricity tariffs incurred by the customers are also low. On another side, the cost of renewables technology is still high to the extent that investors in renewables projects cannot accommodate to offer tariffs that are competitive with those associated with the subsidized fuel prices.

From the customers' point of view, different approaches need to be explored to manage their cost of energy such as improving appliances efficiencies and building distributed generations (DG). The concept of small scale DG has emerged as an approach for the consumers to manage their cost of energy. A solar PV system is a suitable candidate for DG due to its simple structure and low cost as compared to the other renewable technologies. This could be further developed by aggregating DGs to form virtual power plants (VPP).

The objective of this research is to explore the economic feasibility of integrating solar PV systems as DGs to KSA's power system through VPPs. These VPPs are composed of demand centers as well as solar panels on the distribution side. For this study, a model of the KSA power system is created, which consists of the existing generation units, a simplified transmission system model and the regional demands. The model is built and simulated through PLEXOS software. The VPPs are modeled with demand profiles along with forecasts of the PV generation and incorporated to the different areas in KSA. Consequently, the VPPs will be operating at the premise of their respective area's characteristics in terms of system's price, which reflects the regional demand, types of fuel burned and generation technologies. By surfing the literature, it was observed that most of the efforts extended in the field of VPPs were focused on simulating a single VPP of a system, modeling the interaction between the VPP manager and DGs owners and providing ancillary services. However, this thesis attempts to model multiple VPPs located in different sites of the KSA power system to investigate the impact of the geographical location and system's features of each area on its respective VPP.

In the first case (Case 1), the model will be simulated with the objective of minimizing the overall system cost. Also, in this case, the distributed energy resources (DERs) of the VPPs are assumed to be operating individually, so that they have no access to the grid to export any excess generation they have. In Case 2 of the study, the simulation is run with the objective of maximizing the profit of each VPP, as they will have the leverage of generating revenue from exporting their excess generation to the grid. In a third case (Case 3), the whole system, inclusive of the VPPs who have access to the grid, will be simulated. The simulation results of all cases will be analyzed to determine the financial positions of the VPPs along with the benefits realized from installing the PV systems. It is noteworthy that the Levelized Cost of the PV system, which covers the investment and operational cost, is used as an operational cost input. Accordingly, the more contribution of PV generation to meet the demand in the simulation is an indication of higher feasibility to invest in PV systems, rather than a real operation, and the contrary applies.

As the fuel prices are key factors that characterize the market condition under which the PV systems will operate, multiple fuel pricing scenarios are considered in this study. The VPPs demand profiles considered represent households' demand in most of the cases, unless specified in some scenarios where industrial loads are addressed. Moreover, as energy storage systems (ESS) are usually coupled with the PV systems, the economic feasibility of installing ESS is also explored.

Following this Introduction, the thesis is organized as follows: Chapter 2 offers a comprehensive Literature Survey of the VPPs, PV systems and ESS, followed by the Methodology explained in Chapter 3. The subsequent chapter (Chapter 4) provides information about the KSA power system, which is the case used in this thesis. The results and discussion are addressed in Chapter 5, which is followed by the Conclusion and the suggested Future Work.

Chapter 2: Literature Survey and Research Objective

2.1 Virtual Power Plant (VPP)

According to the European energy efficiency directive, an Aggregator in power systems is defined as “a demand response service provider that combines multiple short-duration consumer loads for sale or auction in an organized energy market”. However, the term ‘Aggregator’ does not always refer to the management of demand, as the management of generation units available in the demand side is also considered amongst the function of an aggregator [1]. Accordingly, an aggregator is also defined as “a company that acts as an intermediary between electricity end-user and distributed energy resources (DER) owners, and the power system participants who wish to serve these end-users or exploit the services provided by these DER” [2]. Moreover, the aggregator can be referred to as a virtual power plant (VPP). A VPP is defined by the project named as Flexible Electricity Networks to Integrate the Expected Energy Evolution (Fenix) as: A VPP aggregates the capacity of many diverse DER, it creates a single operating profile from a composite of the parameters characterizing each DER and can incorporate the impact of the network on aggregate DERs output [3].

The VPPs have attracted a great deal of interest by researchers in the area of power systems operation and planning. This is because VPPs can open doors for the DERs to provide their services on a larger scale, as it allows DERs to participate in the wholesale market in the system through a variety of services such as energy, capacity, demand response and ancillary services. Individual DERs are not able to participate on their own in the wholesale market either due to technical limitations, such as availability of a network, or due to policy reasons. For instance, in Germany, the transmission code says that for a control power plant to sell a reserve service, it has to be of a capacity of 30 MW or more [3].

In attempts for exploring the feasibility of VPPs, many models have been proposed in different studies in the literature. The work presented in [4] utilizes Fenix's definition of a VPP, as it models a VPP as a system that consists of two distributed generators (DG) represented by synchronous machine, hydraulic turbine governor and an excitation system. Also, the VPP model includes dynamic loads. The VPP model along with the main grid model, which includes static loads, was developed using Matlab Simulink's library. The model was run to simulated different operation scenarios of the VPP by varying its generation and load. The study concluded with proving the possibility of a VPP to exchange power with the grid.

A model of a VPP with demand response and energy storage was proposed in [5] and the effect of that model on the load profile, balancing and loadability of the Australian National Electricity Market (NEM) for the year 2020 was discussed. The VPP's operation was modeled through an optimization formulation that aims to minimize the cost of electricity supplied from the grid. The optimization takes into consideration the constraints of the grid, the VPP storage system such as the min/max charging rate, min/max state of charge and generation-load balance. For this model, an hourly prediction of the electricity price was developed using core vector regression (CVR). The input of the price predictor was historical and simulated data from the system operator related to the system's inflexible demand, conventional generation (type, capacity, and area), renewable generation as well as the interstate line limits. According to the predicted prices, the flexible demands take demand response action. Considering the post-demand-response load, the total load (flexible and inflexible) is used along with the generation offers to run a market simulation using PLEXOS. For the sake of market simulation, the generators are assumed to be bidding based on their short-run marginal cost (SRMC), for which the generating units' fuel cost, O&M cost and thermal efficiency are the deterministic factors. The model was simulated in different scenarios with different levels of renewable integration and different levels of demand response. The results showed that increasing the renewables integration without demand response to the price, the system's loadability is reduced. However, with higher response to the price along with the renewables and storage integration, the loadability improves and the required back-up supply from the grid decreases. However, as demand response level keeps increasing to reach a certain level, the system's performance starts to deteriorate in terms of the loadability. This is attributed to the load synchronization, which results in a secondary peak in the system.

The study presented in [1] addresses the decisions made by a VPP manager in discharging its role in terms of the VPP's resources' scheduling, remunerating the resources' owners and the aggregation of resources. The study was performed for a network system of 21 buses, 20 consumers, 26 producers and 23 lines. The system consists of DERs that include wind and PV and also it is featured with demand response facilities. In terms of resource scheduling, it was performed via an optimization formulation that has the objective of minimizing the total cost of energy for the whole system, considering the amount and cost of energy produced by the DERs and supplied from the grid. The cost minimization formula also addresses the demand response actions in terms of load reduction, curtailment and shifting. Moreover, it considers the network constraints as well as the demand response capability constraints. The simulation was performed using Matlab and showed the possibility of utilizing demand response facilities in managing the system's load profile. However, as the software simulation time of this model was 55 minutes, it is difficult for the VPP manager to manage its resources scheduling on a real-time basis.

As far as resources aggregation is concerned, in one case, the resources were aggregated based on their type (wind, PV, ... etc.). In other cases, the K-means clustering algorithm was used based on the energy scheduled obtained in the optimization and the respective cost with different K numbers (4, 5 and 6). The aggregation using the K-means clustering method shows that resources similarity in terms of their classification does appear again in the other methods, the K-means resulted in groups of resources of the same type [1].

For the remuneration of the resources' owners, four approaches were proposed. The first approach was to remunerate each resource owner based on its cost obtained in the scheduling. The second approach is to remunerate individual resources based on the highest scheduling cost of the aggregated group, while the third approach is to remunerate the resources based on the average cost of the group. The last remuneration method is based on the type of the resource. The results show that remunerating based on the highest cost in the group results in the most expensive option, while the other three remunerating approaches lead to the same cost [1].

The work presented in [2] attempts to model the participation of DER in a wholesale market in two cases. In one case, the DER participates directly in the market, while in the other case, the participation is performed through an aggregator. Economic dispatch optimization was performed for the two cases and the interaction between the DER was modeled. The simulation of a single DER operation is to maximize its profit through a tradeoff between the amount of energy to be locally consumed and the amount of energy to be offered to the aggregator. Determination of the amount of energy offered to the aggregator is in response to the energy price offered by the aggregator. Similarly, the aggregator seeks to maximize its profit, where the price of energy it offers to the DERs is a key factor, along with the wholesale market energy price. Pursuing an equilibrium, where both the DERs and the aggregator achieve the objective of maximizing their profits, the interaction was modeled using the Stackelberg game theory. In such a game, the

Stackelberg lead (the aggregator) sets the price, and the other game players (DERs owners) follows the price and act accordingly.

Considering the Stackelberg equilibrium interactions, the comparison of the two cases under consideration has shown that there is a price of aggregation, which increases the price of energy, as compared with the case when the DERs offer their energy to the market directly. Accordingly, less amount of energy will be cleared in the market in the case of an aggregator.

In [6], a model of a VPP that consists of conventional and renewable generation units along with controllable demand centers is proposed. The capacity of the generation units is 6 MW for each of the conventional, wind and solar generation, which brings about a total generation of 18 MW. The demand side of the VPP encompasses 10 houses, 2 commercial loads and 3 industrial loads and the hourly load profile of these demand sectors are assumed for one day. To achieve an optimized operation of such a VPP for the day-ahead (DA) market, three optimization models were proposed: deterministic optimization, fuzzy optimization (FO) and probabilistic optimization. In the deterministic optimization, forecasts of wind output, solar output, DA market price were utilized to develop the objective function that maximizes the VPP profit. Moreover, demand response profiles (load curtailment/shifting) are assumed for each demand sector to serve the optimization function.

For the same objective, the FO algorithm was performed to take into consideration the uncertainties associated with the renewable power outputs. Moreover, multiple scenarios of the renewable power outputs were generated using the Gaussian random function to perform the probabilistic optimization. The optimization was deterministically performed for each scenario and the values of the decision variables of all scenarios are averaged to generate a consolidated scenario. Besides, a real-time/spot market was simulated using Monte Carlo simulation and the optimization was modeled deterministically. The objective function of the optimization model is to minimize the cost of the deviation from the schedule, which is the cost of the additional energy to be purchased or the cost associated with the additional demand response actions.

The results have shown that the energy delivered to the consumers, when the demand response actions are taken, is lower than that when no demand response. Additionally, demand reduction actions are taken when the market price is in the high range and the demand recovery occurs at the periods when the energy market prices are at low levels. Also, it was concluded that the FO model yields a higher profit for the VPP than the other two models (deterministic and probabilistic) and leads to a lower number of operational hours for the conventional generators. Moreover, sensitivity analyses for the level of renewable penetration were performed, which suggested that higher penetration of renewables in the real-time leads to lower profit, as a result of the higher uncertainties.

The work presented in [7] intends to design a heuristic transfer between VPP and the individual generators using mechanism design, which is defined as an economic theory that designs rules of a game to achieve a specific outcome. In the context of this paper, the pursued objective is reducing the overall cost of the system. The authors consider a model of a VPP that consists of thermal generators as well as renewable generators. In one case, the VPP plays an intermediary role between the privately-owned generators and the wholesale markets (Distributed VPP case). In another case, the VPP owns the generators and participate in the wholesale market. The VPP bids in a day-ahead (DA) market and has the chance to adjust its position in real-time in a two-price balancing market (BM). In the balancing market, the transmission system operator (TSO) announces the market conditions, whether it is in a balancing up scenario (additional supply required) or a balancing down scenario, and the associated energy prices. For each scenario, there is a different energy price in the BM. The objective function was to minimize the difference between the VPP's profit in the DA and that of the BM. The simulations results demonstrated that an optimal bid for both distributed and centralized cases is achieved at almost the same point, which is 1.7 MW and 1.8 MW, respectively. However, at the remaining operating points, the cost of the distributed system is slightly higher than the centralized VPP.

The integration of DER through VPPs was discussed in [8], where VPPs were classified as commercial VPP (CVPP) and technical VPP (TVPP). The CVPP aggregates DER to develop a single characterization of a power plant, who can participate in the wholesale energy market. Based on the operating parameters of that DER within a VPP's portfolio, the CVPP controls the resources' operation in a manner that optimizes the VPP's profit. The CVPP provides information about the resources operation and parameter to the TVPP who in turn can use these data to provide balancing services to the system management market. The DERs of a TVPP have to be located within the same geographic area to be able to provide services such as network congestion management and balancing services, which can be offered by aggregation of scattered DERs. In the case study presented in [8], the economic benefit of a VPP was addressed from a probabilistic point of view. It considers 10 generation units each of 6 MW with a 60% availability factor, which can be considered as a close approximation to distributed renewable units. In one case, the units are assumed to be individually participating in an energy market to make contracts based on their offers. It was also assumed that the market imposes penalties for not meeting the offered amount of energy. Therefore, considering the availability factor of the generation units, each of them has a 40% risk of not meeting the offer, which implies a high risk of paying the corresponding penalties and consequently reduces the profits. However, in the case when the 10 generation units are aggregated together through a CVPP who collectively participates in the energy market, the risk will be lower. In such a case, the probability of having all units off at the same time significantly decreases and hence the profit will be higher. Moreover, to manage the penalty payment for not meeting the contracted demand, a CVPP may tend to reduce the amount of energy offered. However, this erodes the CVPP's profit. For the case discussed in [8], the optimization between reducing energy offers for penalty payment management and the profit has shown that the maximum profit can be recognized when the CVPP offers 35 MW.

The design of bidding strategies in day-ahead markets is addressed in [9]. Bidding strategies can be designed in two different types of models: 1) Equilibrium models and 2) Non-equilibrium models. In equilibrium models, each market participant designs its bidding strategy while taking into account the bidding strategies of the other participants until the market reaches a point that is the most profitable for all of the market participants. An example of an equilibrium model is Cournot equilibrium, where market participants make decisions of the amount of their bids based on estimates of the others' bid amounts. Although equilibrium-based models are used for generating companies, they overlook some constraints such as units' ramping rates, minimum up/downtime, start-up and shut-down cost, which does not lead to practical results. Such a shortcoming of the equilibrium models is rectified in the non-equilibrium models, which are capable to address those unit's constraints. Price-based unit commitment (PBUC) model is an example of a non-equilibrium model that relies upon forecasts of the market prices in designing a bidding strategy. Therefore, the accuracy of the price forecast plays a vital role in this model and therefore should be carefully considered. This model can be applied for both generating companies as well as VPPs. The authors in [9] attempted to develop a PBUC optimization model for a VPP that participates in energy and reserve markets while taking into account the network's security constraints, which makes it a security-constrained price-based unit commitment (SCPBUC).

An optimal demand response bidding and pricing for a VPP was proposed by the work presented in [10]. The paper considers a VPP that consists of demand centers, renewable energy sources and a dispatchable generator, which exists as a backup for the renewable energy sources. The demands are fulfilled through bilateral contracts by which the VPP operator charges the demands a fixed rate for energy. In turn, when demand centers provide a demand response service (demand reduction) to the VPP, who will then be bidding such a service in the wholesale market, the VPP is obligated to pay compensation for such a service. The work of [10] aims to develop an optimal pricing scheme for the demand reduction, which would be paid by the VPP to the consumer. The fixed-rate charged by the VPP for the demand is considered as the lower band of the demand reduction price, while the forecasted wholesale market is assumed to be the upper band. Another major factor that is considered in designing a demand reduction pricing scheme is the elasticity factor of demand. The more elastic is the demand, the more demand reduction it is willing to provide. Consequently, the VPP tends to lower its compensation to the consumer pursuing profit maximization. For the case study presented in [10], the wholesale market hourly prices and the renewable sources' hourly output are forecasted in advance and used as input to the optimization model that has an objective of maximizing the VPP's profit. The optimization model also takes into account the unit constraints of the dispatchable generator such as the ramping rate and the startup cost. The model was run for the VPP operation in two scenarios: 1) with demand response 2) without demand response. The results have shown that the VPP recognizes higher profits in the scenario when demand response is enabled. Also, in this scenario, the dispatchable generator operates for a shorter duration. In addition, during the time when the wholesale market price is high, the VPP tends to bid more amount of energy and hence will have more appetite for demand reduction even if that costs the VPP higher prices than the other periods.

The operation of a VPP has been an area of focus for many researchers. To explore such an area, multiple models of a VPP have been investigated in the literature in terms of their optimal operation, where profit maximization is the objective. There are VPP models that include only renewable DERs along with other thermal DGs. Also, some other VPP models consists of demand response features in addition to the renewable DERs. In addition, the role of energy storage systems is being incorporated into the operation of the VPPs. The authors of [11] considers a model of a VPP that consists of a wind farm of a capacity of 50 MW and a flexible load that has the capability to provide a demand response service to the market. In terms of the wind farm's production, a probabilistic model is used to consider the uncertainties. For the demand response, the paper taps into the model adopted by the New York Independent System Operator (NYISO) in its Day-Ahead Demand Response Program (DADRP). In this program, the consumers can bid a demand response service, for which they are compensated if their bid is accepted upon clearing the market. In addition, in order to incentivize the consumers to provide such a service, the cost associated with the amount of energy that was previously cleared in the market but was not consumed is being remitted to the consumers. Accordingly, by bidding a demand response, the VPP can make savings and gain revenue, in addition to the revenue recognized by bidding the wind farm's energy output to the market. The study further considers the cost that a VPP would incur upon providing a demand response service. A function of such a cost has been proposed, which is dependent on the elasticity of the loads and the benefit gained by the VPP.

Considering the VPP's revenue, cost-saving, and the imbalance penalties associated with the wind farm's intermittence, a model was simulated to maximize the profit of the VPP using the General Algebraic Modeling System (GAMS) software. Initial load and market prices from the PJM electricity market were used as an input to the optimization problem. The results have shown that the VPP tends to participate in the market with higher demand response when the electricity price is high and also when imbalance penalties are higher. Also, the simulation proved that the amount of energy offered to the market by the VPP follows the trend of the electricity market price. The study further explored the impact of the load elasticity on the VPP's bidding strategy, and concluded that the more elastic the load is, the more energy offered to the market and hence, the VPP makes higher profits.

Another VPP operation optimization model is proposed in [12], which models managing a VPP that includes flexible and non-flexible loads, thermal generating units that supply the loads and use the grid as a backup. In this model, the VPP manager is responsible to supply the loads with energy, for which they are charged by the VPP manager different electricity prices according to their conditions (flexible or non-flexible). Also, the VPP has the option to request the flexible load to reduce its demand, whenever it is economically feasible, provided that a penalty must be paid for such an action according to the amount of the reduced demand. Also, the VPP can bid its excess energy to the market, by which more revenue is recognized. Accordingly, the VPP is expected to operate in a manner that maximizes its profit considering its cost of generation, cost of purchased power, penalties and the revenue associated with meeting the demand of its loads as well as the exported energy. A profit maximization objective function has been developed and simulated based on assumed values of the different energy prices over a one-day period using GAMS. The simulation was performed for scenarios with different electricity prices to the loads and different penalties in each scenario. It was concluded that the VPP's profit will be higher in the case when electricity prices are higher, even though the penalty for not meeting the demand is higher. Also, the output of the generation units, energy export, energy import and the non-served load were obtained.

The author of [13] proposes a model that is similar to the one of [12]. However, in this model, the VPP does not incur the cost of the demand response nor pays a penalty for demand reduction. Conversely, the VPP bids such demand response service to the market to make additional revenue and maximize the profits. Also, this model is more comprehensive, as it accounts for the thermal generator's startup cost as well as the ramping rates. The demand response action is modeled in a way that is dependent on the load elasticity and the market's demand response price, which is assumed to be bounded between the market energy price and the VPP energy price, that is used to charge the demand centers for their consumptions. The Romanian power system, which is inclusive of renewable DERs, was utilized and simulated as a Bulk VPP. The output of the wind DERs was forecasted considering some historical data. For the energy prices, the paper refers to real data from the Romanian Transmission and System Operator (Transelectrica). The study addresses the unbalance between the forecasted and real renewable output through a balancing market, where the VPP takes a balancing action associated with a balancing. The simulation results have validated the capability of the demand response actions to reduce the unbalance between the forecasted and the real renewables output.

While the research focus has been considerably directed toward optimizing the operation of a single VPP, the work of [14] discussed and simulated a central control of multiple VPPs who can exchange power with each other in an attempt to explore the economic benefit of such a control. The paper considers three VPPs, that include thermal generation units, combined heat and power (CHP) units as well as PV units. Also, each VPP has a different demand for heat and power that have to be met. In this study, it is assumed that the VPP owns the demand centers and hence, the financial transaction between the VPP manager and the loads does not appear in the simulation. Accordingly, the objective function of the carried-out simulation is to minimize the production and the emission cost of all generation units within the VPPs. The operational cost of the thermal generation units is obtained using the quadratic cost function. The cost of the CHP units is determined using a convex function that is proportionate to the amount of heat and power produced.

The model presented in [14] was simulated in two cases; the first case is when each VPP operates individually to meet its demand through its own resources and the second case is when the three VPP are centrally operated. The results have proved that the central dispatch of the VPPs' generation units brings about more benefits to the system. In such a case, the overall load can be met with a lower cost of fuel and a lower cost of emission, as compared to the case of the individual operation. The central dispatch of a VPP is also explored in [15] but using another approach. Unlike the method adopted in [14], where the grid operator performs the economic dispatch of all generation and CHP units of each VPP, the method followed in [15] assumes that the grid operator does not have access to the operational characteristics of each individual generation units of the VPP. However, it has information about the aggregate characteristics of a VPP. For the study, the aggregated characteristics are determined by adding those of the individual generation units. For instance, the cost function of a VPP is obtained by adding the cost functions of each generation unit within the VPP. Similarly, the minimum and maximum generation units of the VPP are calculated by adding those of each individual unit. Using these characteristics, the economic dispatch is carried out for the VPP as a phase 1 dispatch. In the 2nd phase, using the results of phase 1, the economic dispatch of the units within the VPP is performed.

This approach was implemented on a 3-bus system testbed that consists of wind and thermal generation units along with the local loads. Each bus is considered as a VPP. For the sake of comparison, the conventional approach of centrally dispatch all individual generation units was performed for the same system. The approach proposed in [15] have demonstrated validity and resulted in lower generation costs than the conventional approach.

Another optimization model of a VPP operation is proposed in [16] for a VPP that consists of renewable DER, thermal generation DG and battery energy storage system. The maximum capacities of renewable resources are 12 MW for the wind power and 2 MW for the PV. The capacity of the thermal DG is 4 MW and that of the battery energy storage system is 1 MW. The optimization function is to maximize the profit of the VPP by increasing its revenue generated through the energy exchange in the day-ahead market and reducing its consumption cost and cost of generation. The study considers a quadratic function to represent the benefit recognized by the load from the consumed energy. It is of the VPP's best interest to maximize this benefit, while considering the load to be flexible and responsive to the day-ahead price. This study also assumes no financial transaction between the VPP manager and the load centers and the only transaction takes place externally in the market. The cost of the VPP is represented by the thermal unit's production cost, start-up cost and shutdown cost. The paper ignores the operational cost of the battery energy storage system. The model was simulated using GAMS/Matlab for two different cases, where the market price is the varying factor between the two cases. In each case, four scenarios of the renewable DER's availability are considered. The results demonstrated that the model can obtain feasible solutions while satisfying the constraints. It was concluded that the VPP's profit is at maximum in the higher-marker-price scenario and when the renewable DER are at their highest availability. This is due to the higher revenue recognized by the exchanging energy in the market at a high price. Also, it is due to the lower cost incurred due to the less energy produced by the thermal unit, where the balance is compensated by the renewable units.

Short-term energy trading and optimal operation of a VPP is also explored in [17], which adopts a multi-scenario model to simulate the operation of the VPP under study. The multi-scenario approach is used to account for the uncertainty of the energy day-ahead market price and the output from the renewable DERs. A large number of scenarios is generated for the whole system's operation, which is based on the number of scenarios available for the day-ahead market price and that of each renewable generation unit. A certain probability is assigned for each of the systems' scenarios, where those probabilities add up to unity. The objective function of the proposed model is to maximize the VPP's profit through maximizing the energy bidding revenue. Also, the revenue can be maximized through VPP's internal energy supply to the demand centers at the internal electricity price. Profit maximization can also be achieved by reducing the operational cost of thermal generation units available within the VPP and reducing the imbalance penalty. The optimization is performed for the objective function for each of the systems scenarios, while being multiplied by the corresponding probabilities and added up to find a solution that takes into account all possible scenarios.

The model proposed in [17] was performed for a case study, which is a VPP that consists of two wind DERs, a thermal generation unit, a pump storage plant and a flexible load. The generated multiple system scenarios were used as input to the simulation model along with the forecasted VPP's internal load and internal electricity price. The simulation was performed using CPLEX, which obtained results for the different decision variables such as the VPP's bidding strategy, hourly profit and hourly operation of the internal components of the VPP. The results demonstrated that the bidding strategy follows the trend of the day-ahead electricity price, as the VPP will increase the bid value at higher prices to generate more revenue. In terms of the internal components' operation, it was observed from the results that the pump storage plant is absorbing energy during a low price period to discharge such energy in the peak hours, where the prices are high. Also, in cases where the market price is high, more demand response actions are taken in order to avail more energy for the VPP to bid in the market. The thermal generation unit of the VPP operates at its maximum in the scenario where the market price is high.

Two different VPP operation strategies were developed in [18] based on the Stackelberg game, which is an economic theory that studies the interaction between the different participants involved in economic transactions. The study considers multiple VPPs that consists of load centers, electric vehicles in addition to thermal generation units, which are operating within a market environment. The case study adopts the generation and demand data of the UK power supply, while adopting that proportionately to the IEEE 30-bus system, where every five buses are aggregated to form a single VPP. In one scenario, it is assumed that the market operator is the leader of the game, by whom the loads of each VPP are dictated. The VPPs' operators in turn follow the leader's instruction and operate accordingly with the objective to minimize the losses of the VPP. In the second scenario, the VPPs' operator becomes the game leader to set the demand response prices and the market operator uses those announced prices to optimize the two objective functions of minimizing the VPP's operating cost and minimizing the electricity bills of the consumers.

The simulation results in both scenarios proved the validity and feasibility of the VPP. In the first scenario, the losses were found to be lower than the business-as-usual case when the system operates without scheduling. Moreover, in the second scenario, the VPP profit was greater than the case when the system operates normally without a VPP, as a result of minimizing the VPPs' operating cost and consumers' electricity bill.

2.2 Solar PV System

2.2.1 Operation Principle

The operation of the solar PV system can be defined as the conversion of the energy received from the sun into electrical energy. This energy conversion is performed utilizing panels that are manufactured of semiconductors. The most effective materials used in manufacturing these panels are silicon and thin films. Thin-film panels are manufactured of micrometers silicon layers in addition to non-silicon layers. When these semiconductor-based panels absorb the energy radiated from the sun, the electrons of the atoms making the panels are excited to move and accordingly create a DC current. This DC current then takes its path through a circuit designed to facilitate utilizing this current for different applications. Solar PV system is dominant among other renewable energy technologies in terms of installed capacity. According to a report issued by the International Renewable Energy Agency [19], a total of 94 GW of Solar PV capacity has been installed only in 2018, which represents a 55% of the total renewable capacities added in that year.

2.2.2 Applications

The installation of the PV panels varies between being rooftop or ground-mounted according to space availability and the application. Solar systems are deployed over multiple applications. Solar PV systems are installed to supply power to various types of loads such as residential and industrial loads. Also, they are available in different configurations depending on the applications. In some cases, the solar PV systems are installed in an off-grid system where the load is not connected to the grid. In this case, energy storage is required to ensure continuous energy supply in the absence of the solar PV's source of energy (sun radiation). The sizing of the PV and the storage system for an off-grid system is an optimization problem that requires studying the load behavior and the radiation forecast of the site. In other designs, the system is connected to the grid, which supplies the demand center with energy in case the solar PV system is not operating or not generating enough energy.

2.2.3 Technical Factors

Several factors have an impact on the output of the solar PV system. The primary factor is the intensity of the solar radiation and the sun's cyclic behavior in the site in which the solar farms are located. Moreover, the solar radiation absorbed by the panels is impacted by the Earth's atmospheric condition as it is reduced due to reflection and scattering. Also, the cleanness of the panels has a significant impact on the systems energy yields. Therefore, Solar PV systems installed in areas with dusty weather are subject to higher degradation effect than those in areas with no dust if no cleaning mechanisms are in place. In other words, PV output is dependent on the weather conditions and hence it is site-specific, as different sites have different PV output.

Besides weather conditions, there other considerations that contribute to the solar PV system yields such as the efficiency of the material by which the cells are manufactured, panels installation tilt angles, panels orientation as well as the availability and the effectiveness of the maximum power point (MPPT) tracking system. Also, the size of the inverter that converts the panel's DC power into AC plays an important role in the AC power output from the solar PV systems. The inverters should be sized to withstand the DC power created on the panels. However, the selection of the inverter size should be optimized with the system cost.

2.2.4 Economics

The adoption of the solar PV system is motivated by environmental factors as it displaces the energy generated by thermal generation units that are based on burning fossil fuels. So, the solar PV systems contribute to the reduction of the carbon dioxide emission, which is considered among the issues contributing to global warming. While the solar PV systems are environmentally friendly, its cost was the main hurdle of high adoption. However, due to advancements in the technology of manufacturing panels and inverters, the solar PV system cost has been evolving to be more competitive. As reported by IRENA in [20], back in 2010, the Levelized Cost of Electricity (LCOE) of the solar PV system was 370 $/MWh. This number has dropped dramatically in 2018 to reach 85 $/MWh. In this regard, KSA has witnessed a world record-breaking bid for a utility-scale 300-MW solar PV project in Sakaka area with an LCOE if 23 $/MWh [21].

2.2.5 Modeling

For a power system study that investigates the operation of a system that includes a solar PV system, the hourly output of the PV systems is required to be incorporated into the model developed for the study. In order to determine the time series of the solar PV output of a particular location while reflecting their stochastic natures, there are two approaches adopted by the researchers. The first approach is the stochastic method, which is based on statistical analyses of the site's radiation data points and their associated mean, deviation and probabilities. Such analyses can be carried out with the help of statistical theories among which are the Monte Carlo and the Markov model. The work presented in [22] adopts the Markov model along with a clustering algorithm called Fuzzy-C-Mean clustering. On the other hand, a deterministic approach can be utilized to determine the time series of the solar PV output. This methodology is based on actual measurements of solar radiation using satellite or testing stations which can be converted into energy output using specified formulas.

2.3 Energy Storage System

2.3.1 Energy Storage Technologies

Energy storage systems are available in different forms, among which are pumped hydro storage, electro-mechanical storage as well as electrochemical storage. In the pumped hydro storage system, energy is charged during off-peak demand time by pumping water into a reservoir located at a high altitude. When required, energy is discharged by allowing the stored water to flow from its high reservoir where the flow becomes a prime mover for a generator. One of the electro-mechanical storage technologies is the compressed-air storage system, which operates in a similar principle as the system absorbs air and store in an air tank during the off-peak time (charging mode) and discharge its energy through discharging the air from the tank to provide mechanical energy to a generator, which converts it into electrical energy [23]. Another electro-mechanical storage technology is the flywheel storage system where the kinetic energy of an object rotating around a fixed axis is utilized. In the charging state, the rotating shaft receives power from the grid by which it operates as a motor. As the shaft is coupled with an electrical machine that can be reversed, in a discharged state, the rotation direction is reversed so the systems become in a generation state where it generates electricity to the grid [24]. One of the commonly used electrochemical storage systems is the lithium-ion storage system, which operates based on the chemical reaction. When a load is connected to a lithium ion-based battery, the electrons are released from the anode to travel through the load to the battery's cathode. This process continues until all electrons are released and battery becomes fully discharged. On the other hand, when the battery receives electric current from the grid, those electrons travel back from the cathode to the anode until the battery is fully charged.

2.3.2 Applications

Energy storage systems are capable of providing a wide spectrum of services that are utilized by the transmission system operators and the energy end-users be it in the residential, commercial or the industrial sectors. For instance, energy storage systems can be adapted for seasonal storage where energy is stored in the winter and discharged during the summer season during high demand periods. Also, they can be employed to provide black starting services, energy arbitrage, network congestion management. Also, given the emerging pace of the renewable energy systems cost decline along with the environmentally driven efforts to decarbonize the energy sector, renewable energy resources adoption is ramping at a fast pace. As this brings high renewables penetration levels, energy storage (ES) systems become of necessity to address the pressing issues associated with the stochastic nature of the renewables. In order to achieve this goal, the network is required to be equipped with elements that make it flexible enough to accommodate the renewables volatile output and maintain a real-time generation and demand balance. One of the measures to avail such flexibility lies within the energy storage systems as they are capable to support the operation of the transmission system in maintaining its technical parameters such as voltage level, frequency and reserves requirement [25]. The level of flexibility offered varies among the different energy storage technologies. The decision of the technology to be adopted is contingent on the application of the system as each technology can offer a different level of flexibility, which is different from one application to another according to its characteristics.

For instance, pumped hydro storage systems have an E2P ratio (Energy to Power ratio or discharge duration) of more than 10 hours. Accordingly, they are suitable for the application of seasonal storage. However, with these characteristics, pumped hydro storage systems are not suitable to be employed for frequency response or voltage support services. In turn, the electrochemical storage systems such as lithium-ion batteries are featured with the short E2P ratio characteristic as they are capable to discharge in less than an hour. This advantage, in addition to the technology improvement in parallel with the evolution of renewable energy technologies, makes lithium-ion batteries favorable over the other storage technologies for renewables applications.

According to [24], as of mid-2017, the pumped hydro storage system is by far the most adopted storage technology worldwide with a total installed capacity of 169 GW representing 96% of all installed energy storage technologies. With this in mind, it can be inferred that the majority of the storage systems available nowadays are utilized for seasonal storage rather than the network system support. This is driven by the high cost of the other technologies as compared to the low cost of pumped hydro storage system.

2.3.3 Economics

The cost of the energy storage systems relies heavily on the storage systems' technical parameters offered by different technologies. As such, among the factors that determine the cost of a certain technology are the response time, depth of discharge (DoD), discharge efficiency and the cycle life. The energy system cycle life and response time are conversely proportionate to the cost of the system. To illustrate, as the pumped hydro storage system has a cycle life (100,000 cycles) and slow response (10 hours), the pumped hydro installation cost of 100 $/kWh is more competitive than that of the other technologies such as the lithium-ion, where the installation cost is in the range of 250 – 1,000 $/kWh. The lithium-ion batteries are featured with a lower cycle life of 20,000 cycles and a faster response in a range of 1-4 hours. [24]

In fact, this explains the main challenge preventing the large-scale adoption of the lithium-ion batteries of network system operation enhancement as the flexibility features are costly to avail.

However, in the field of lithium-ion batteries manufacturing, there is a promising cost reduction potential due to technology improvement, larger scales production capacity and the accelerated learning curve. This has been witnessed in the cost reduction trend for lithium-ion batteries in Germany, where the installation cost has dropped from 2,515 $/kWh in 2014 to 1,017 $/kWh in 2017. [24]

2.3.4 Modeling

As energy storage systems are being considered in power systems to address network operational issues, it is fundamental that the simulation of the system unit commitment includes the energy storage systems to measure their impact. To do so, energy storage systems must be modeled in a manner that reflects their characteristics. In literature, multiple efforts are exerted to address energy storage systems in unit commitment studies for power systems with renewable energy sources penetration and multiple optimization techniques were explored for such purpose. When an energy storage system is available in a power system in the form of a battery-swapping station that charges electric vehicles, it is required to account for the time of charging the vehicles, the number of times the charging operation takes place and the residual capacity in the station upon charging the vehicles. With some statistical information, this can be achieved by utilizing a probabilistic approach such as the Monte Carlo method, as presented in [23].

Due to the intermittency of renewable resources, stochastic optimization techniques are adopted for modeling the storage systems in unit commitment to ensure a real-time power balance between the available generation and load. This is due to the fact that the operation of the storage system is actually a real-time response to the operation of renewables energy resources, which is intermittent. On the other hand, a deterministic approach can also be used to model energy storage in such power systems. This deterministic modeling can be achieved by assuming that the renewable production is perfectly forecasted over the simulation period on an hourly basis and accordingly the energy storage system operation profile is also determined [28].

2.4 Research Gap

It can be observed from the literature review that most of the research efforts related to the concept of VPP were focused on:

- Optimizing the operation of a single VPP within a system
- Modeling the interaction between a VPP manager and its DERs' owners.

However, our study will build on the previous efforts in this area and complement it by the following contribution means:

- Consideration of the different sites, where VPPs can be located, to account for zonal/nodal pricing of each location.
- Study the economic impact on VPPs associated with the availability of the renewable natural resources over the different areas, as each area has its own solar irradiation profile.

2.5 Research Objective

The objectives of this work are:

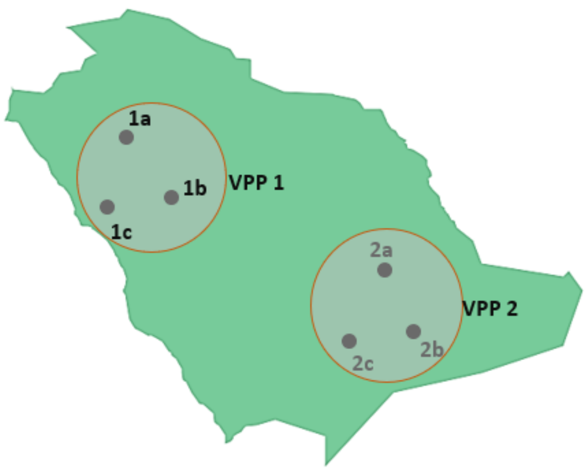
- Explore the economic feasibility for VPP owners to creating VPPs over different areas across the KSA of Saudi Arabia (KSA).
- Study the economic impact, from the system operator's perspective, of centrally operating those VPPs.

The scope of this work is to model virtual power plants by aggregating multiple DERs. The DERs constitute load centers, PV panels and ESS, which can collectively bid their excess energy to a wholesale market. Similar to any market participant, the VPPs will have an objective of maximizing their profit, which can be achieved by minimizing the production cost and the cost of energy consumed. It can also be achieved by maximizing the revenue generated by selling the excess energy to the market.

Chapter 3: Methodology

3.1 Scenarios

The above objectives can be achieved through investigating the DERs' economic parameters in different scenarios of the DERs' operation as presented in Figure 3.1:



Case	Scenario		Parameters
Case 1	Individual DERs	Load Load + PV Load + PV + BES	1. Cost over energy per node. 2. Overall system cost
Case 2	Individual VPP	Load + PV + BES	1. Cost of Energy per VPP 2. VPP Bidding Strategy 3. VPP Profit 4. Overall system cost
Case 3	Central VPP Operation	Load + PV + BES	1. Cost of Energy per VPP 2. VPP Bidding Strategy 3. VPP Profit 4. Overall system cost

Figure 3.1: Illustration of studies cases

- **Case 1:** We will explore the economic parameters of each DER (node), while working individually in different scenarios. It is assumed that the DERs in this case are passive, which means that their energy generated is for local consumption only and not used for participating in the wholesale market.
- **Case 2:** The economic factors will be calculated for an aggregation of DERs to form a VPP while optimizing the operation of each single VPP, which can participate in the wholesale market. In each operational area in KSA, we will form a VPP, which will allow us to compare the VPP's feasibilities in the different areas.
- **Case 3:** The study will be performed assuming a central operation of the VPP.

3.2 System Operation Optimization

The process of running the simulations associated with this study consists of four main steps. This process is depicted in Figure 3.2.

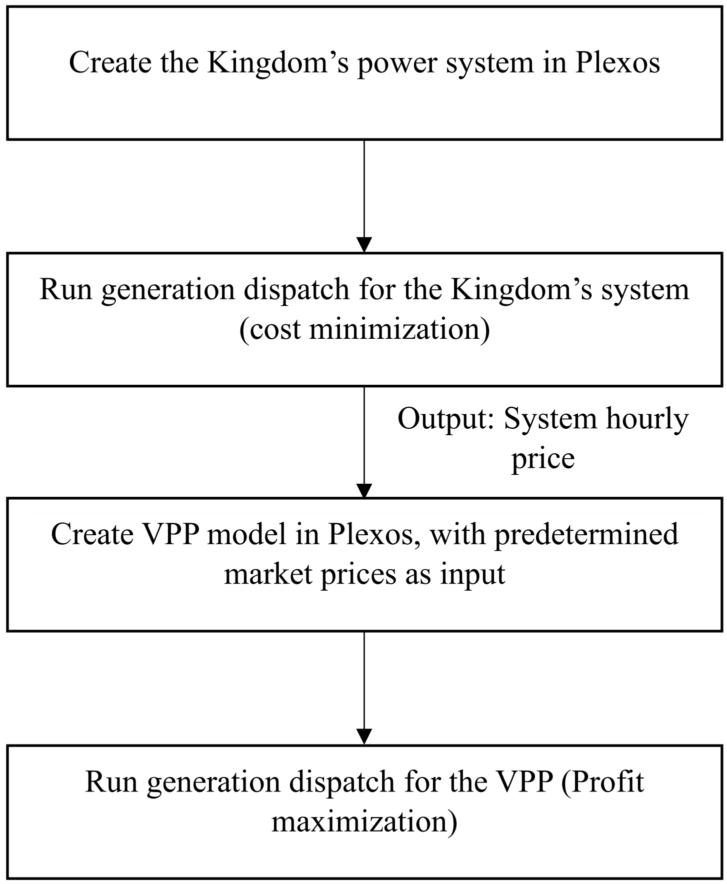


Figure 3.2: Methodology

Step 1:

PLEXOS software is used to create a model that exemplifies KSA's power system including its generation units, transmission system and demand centers. Within Plexos, each element of the power system is created where the user can input its specifications. The input data used for the power system model used in this study are explained as follows:

- Generation units:

All of KSA’s licensed generation units along with their capacities have been considered in this study based on data sourced from Electricity Cogeneration Regulatory Authority (ECRA) official website. For the sake of simplicity, generation units of similar technologies and capacities have been aggregated. The specifications of the generation units such as ramping rates, heat rates, minimum stable level, variable operating and maintenance (O&M) charge, minimum uptime and minimum downtime were also considered as inputs to the model. Typical data of such parameters for units of similar technologies were sourced from literature and adopted in the model.

- Transmission:

  Due to the absence of detailed information about the transmission system of KSA, a simplified model of 6 nodes is used in Plexos, where each node represents an operational area, which area:

  - Eastern operational area (EOA)
  - Western operational area (WOA)
  - Central operational area (COA)
  - Northwest operational area (NWOA)
  - Northeast operational area (NEOA)
  - Sothern operational area (SOA)

  The interconnection between these areas is as depicted in Figure 3.3.

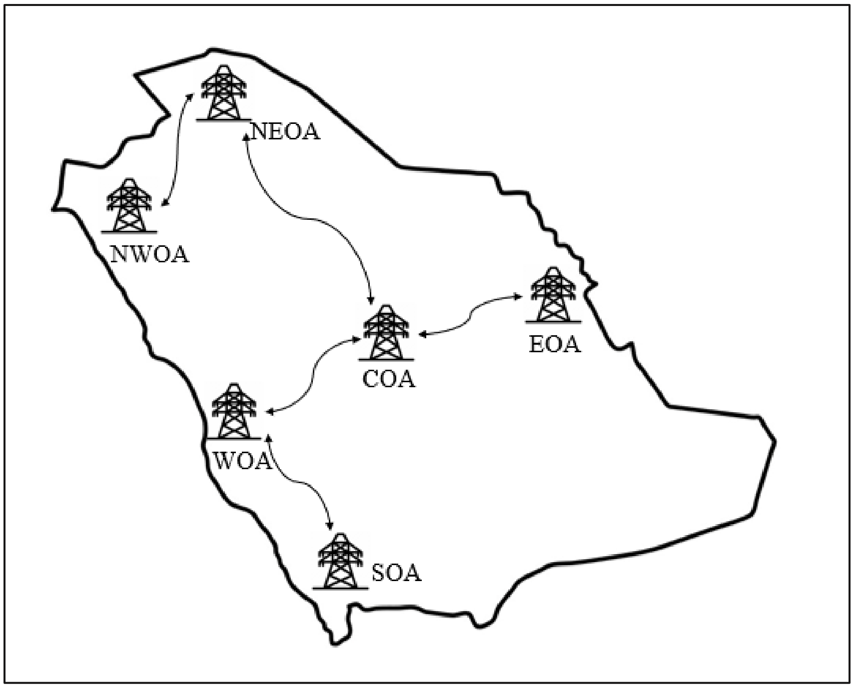


Figure 3.3: Saudi Arabia Interconnection System

- Demand side:

  As each node of the model represents an operational area, the demand data of those areas published by ECRA were utilized in the model. ECRA's 2018 Statistical Booklet entails information about the regional monthly peak demands and typical summer and winter daily load profiles. As shown in Figure 3.3, the nodes NWOA and NEOA are connected to COA, hence, they are assumed to be partial loads of COA representing together 10% of COA load. These data were utilized and extrapolated to create a time series of hourly demand for each area for the full year has and used as input to the model.

  With the consideration of the hourly demand data of each node/area, along with a typical residential and industrial load profiles, the hourly demands of the VPPs located in each area were developed.

Step 2:

Based on the model developed in step 1 and its input assumptions, a unit commitment was simulated with an hourly time granularity for a full year. The objective function of the unit commitment was to minimize the overall system cost. The formulation of the objective function along with constraints' equations are:

<u>Indices</u>

i	Thermal Generating Unit index
j	System node index
m	System node index, representing the receiving end of a transmission line.
h	Hourly period scheduling index

<u>Parameters</u>

FC_{ih}	Cost of fuel burned by thermal generating unit *i* at hour *h* [$/GJ]
VOM_i	Variable O&M cost of thermal generating unit *i* at hour *h* [$/MWh]
a_i	Second-order heat rate increment of generating unit *i* [GJ/MWh^2]
b_i	First-order heat rate increment of generating unit *i* [GJ/MWh]
c_i	Heat rate base of generating unit *i* [GJ]
RU_i	Ramp up constraints for thermal generating unit *i* [MW/h]
RD_i	Ramp down constraints for thermal generating unit *i* [MW/h]
$\underline{p}_i$	Minimum stable generation level of thermal generating unit *i* [MW]
$\overline{p}_i$	Maximum generation capacity of thermal generating unit *i* [MW]
MUT_i	Minimum uptime for generating unit *i* [hour]
MDT_i	Minimum downtime for generating unit *i* [hour]

Variables

p_{ih}	Scheduled power generation of thermal generating unit *i* at hour *h* [MW]
u_{ih}	Binary variable to represent on/off status of thermal generating unit *i* at hour *h*
$Start_{ih}$	Binary variable to indicate if the generation unit *i* at hour *h* is in a turn-on [Logic 1: turn-on]
$Stopt_{ih}$	Binary variable to indicate if the generation unit *i* at hour *h* is in a turn-off [Logic 1: turn-off]
G_{jh}	Total hourly generation from all generation units at node *j* at hour *h* [MW].
D_{jh}	Hourly demand of node *j* at hour *h* [MW].
L_{jm}	Hourly power flow from node *j* to node *m* [MW].

$$\underset{p_{ih}, u_{ih}}{minimize} \sum_{i,h} \left(FC_{ih}\, u_{ih}\, (a_i\, p_{jh}^2 + \; b_i\, p_{ih} + c_i) + VOM_i\, p_{ih} \right) \qquad \forall\, i, h \tag{3.1}$$

Subject to:

$$\underline{p}_i u_{ih} \leq p_{ih} \leq \overline{p}_i u_{ih} \qquad \forall\, i, h \tag{3.2}$$

$$G_{jh} - \; D_{jh} - \sum_{h} L_{jmh} = 0 \qquad \forall\, j, h, m \tag{3.3}$$

$$p_{i,h-1} - p_{ih} \leq RD_i u_{ih} \qquad \forall\, i, h \tag{3.4}$$

$$p_{ih} - p_{i,h-1} \leq RU_i u_{i,h-1} \qquad \forall\, i, h \tag{3.5}$$

$$u_{ih} \geq \sum_{i,k=h-MUT}^{h} Start_{ik} \qquad \forall\, i, h \tag{3.6}$$

$$u_{ih} \leq 1 - (\sum_{i,k=h-MDT}^{h} Stop_{ik} \quad) \qquad \forall\, i, h \tag{3.7}$$

In this scenario, the objective function of the system's unit commitment is defined in equation (3.1), which minimizes the overall cost of generation. Such cost is dependent on the generation units' heat rate function, cost of fuel and variable O&M cost. The generation limits constraints of the generation units are considered in equation (3.2). The constraint of equation (3.3) addresses the optimal power flow of the system's network, based on nodal power balance. The limits of the generation units' ramping down and ramping up are formulated in equation (3.4) and (3.5), respectively. Equations (3.6) and (3.7) sets the constraints that take into account the generation units' minimum uptime and minimum downtime, respectively.

Based on this unit commitment, the hourly price of each node is taken as an output to be used in the next step. The concept of setting the price at a certain node will be discussed in Section 3.3.

Step 3:

In this step, each of the VPPs considered in this study are created in a separate model. For each of EOA, WOA, SOA, and COA, we are considering a testbed VPP that is designed to have a residential or industrial demand profile that is developed in light of the corresponding region's load profile based on the actual data published by ECRA. Also, the VPP includes solar PV to serve its local demand and export the excess energy to the grid. In some cases, the VPP is augmented with energy storage in an attempt to have the VPP acting smartly where the PV's energy that is more than demand is exported to the grid during the time that makes the most economic benefit for the VPP. In order to simulate the operation of the VPP within its corresponding area which is set by the marginal cost of the existing generation units at each area, the hourly prices of each area determined in step 2 are used as input to the model that constitutes the VPP's elements. As the VPP's energy generated from its PV does not cover the VPPs' demand due to the intermittent nature of the PV, the VPPs require energy supply from the grid four certain hours of the day (e.g. night time). Instead of modeling the whole grid and its generation units for this purpose while avoiding their consideration in the optimization function, a proxy generator of a fixed output with zero cost is created. As the hourly prices that are reflective of the system's cost are forced to the VPP's model, having a generator with a zero cost does not affect the simulation. Similarly, in order to have a demand that receives the VPP's export, a proxy demand center is also created. So, the VPP's model in PLEXOS includes its demands center and generation assets, namely PV and storage, in addition to the proxy generator and demand that supply the VPP with the energy it requires in the absence of PV or storage and also receives the VPP's excess energy.

Step 4:

As the hourly prices of the areas are forced to the VPP's model in order to ensure simulating its operation in view of the system's existing asset's cost, the objective function of the optimization is no longer a cost minimization of the system. Instead, the objective function turns to be a profit maximization of the VPP's assets (PV and energy storage). Accordingly, another term is added to the optimization, by which the revenue from the VPP is maximized. In other words, the objective function aims to maximize the generation of the VPP's assets during time periods where the area's price is higher while meeting its demand at the lowest possible cost and satisfying the technical constraints of its assets such as the charging efficiency, minimum and maximum state of charge (SoC) as well as the maximum hourly charge/discharge capability. The formulation of the profit maximization objective function along with constraints' equations are stated below in equations (8) to (13).

Indices

i	PV Unit index
j,m	Nodes indices
k	Storage unit index
h	Hourly time period scheduling index

Parameters

$\bar{s}_{\boldsymbol{k}}^{s}$	Maximum hourly charging capacity of storage unit k [MW]
$\bar{s}_{\boldsymbol{k}}^{p}$	Maximum hourly discharging capacity of storage unit k [MW]
VOM_i	Variable O&M charge of PV unit i, which is represented by the LCOE [$/MWh]
$VOM_{\boldsymbol{k}}$	Variable O&M charge of storage unit k, which is represented by the LCOS [$/MWh]
$\underline{x}_{\boldsymbol{k}}$	Minimum state of charge (SoC) for storage unit k [MWh]
$\overline{x}_{\boldsymbol{k}}$	Maximum SoC for storage unit k [MWh]
$\eta_{\boldsymbol{k}}^{s}$	Charging efficiency of storage unit k
$\eta_{\boldsymbol{k}}^{p}$	Discharging efficiency of storage unit k
P_h	System hourly price [$/MWh]

Variables

$s_{\boldsymbol{k}h}^{s}$	Energy charged to storage unit k during at h [MWh]
$s_{\boldsymbol{k}h}^{p}$	Energy discharged from storage unit k at hour h [MWh]

PV_{ih} Energy produced from PV unit I at hour h [MWh]

x_{kh} SoC for storage unit k during hour h [MWh]

G_{jh} Total hourly generation from PV or storage units at node *j* at hour *h* [MW].

D_{jh} Hourly demand of node *j* at hour *h* [MW].

L_{jm} Hourly power flow from node *j* to node *m* [MW].

$$\underset{PV_{ih}, S_{jh}^{p}}{maximize} \sum_{i,k,h}\left(PV_{ih} + S_{kh}^{p}\right)P_h - PV_{ih}\,VOM_i - (\,S_{kh}^{p} + S_{kh}^{s})VOM_k \quad \forall\, i, k,\ h \tag{3.8}$$

Subject to:

$$G_{jh} - D_{jh} - \sum_{h} L_{jmh} = 0 \qquad \forall\, j,\ h, m \tag{3.9}$$

$$s_{kh}^{s} \leq \bar{s}_{k}^{s} \qquad \forall\, k,\ h \tag{3.10}$$

$$s_{kh}^{p} \leq \bar{s}_{k}^{p} \qquad \forall\, k,\ h \tag{3.11}$$

$$\underline{x}_k \leq x_{kh} \leq \overline{x}_k \qquad \forall\, k,\ h \tag{3.12}$$

$$x_{kh} = x_{k,\,h-1} + \eta_k^{s} s_{kh}^{s} - \frac{1}{\eta_k^{p}} s_{kh}^{p} \qquad \forall\, k,\ h \tag{3.13}$$

Equation (3.8) represents the objective of the VPP, which is maximizing profit via maximizing revenue from the VPP's generation from both PV and storage unit, while minimizing the cost associated with availing these resources. The typical unit commitment studies that address PV and storage consider the VO&M of these resources as zero due to the operational characteristics of these technologies as there is no fuel burning involved for generating any additional MWh. However, in this study, we are evaluating the economic feasibility of bringing these resources in place in view of the marginal cost associated with the existing system, which is manifested in the time series price found in step 2. In order to achieve this, we are treating the LCOE and LCOS of these resources as their VO&M charge in the unit commitment model. Equations (3.9) take care of the nodal energy balance between generation, demand and energy exported from the node. The storage units' hourly charging/discharging capabilities are expressed by the constraints in Equations (3.10) and (3.11). Also, the storage units' depth of discharge (DoD) and the maximum charging limit is addressed in Equation (3.12). Equation (3.13) expressed the constraints associated with the storage units charging and discharging efficiencies.

3.3 System Prices Setting

The objective function of the unit commitment simulation is to establish an operation strategy for all the system's available generation units in a manner by which the demand and transmission constraints are met at the lowest possible cost. The operation strategy refers to the decisions of what generation units to operate, at what level of output and when so that the system's operation cost is minimized. There are multiple cost elements associated with the generation units. Those elements can be of a fixed type or variable according to the unit's production. The fixed cost elements cover the plant's insurance cost, overhead cost and operation and maintenance (O&M) that are incurred by the plant owner regardless of the unit's production. On another angle, the variable cost elements are only incurred when the plant is generating, and such cost is in correlation with the unit's output. Hence, such cost has a unit of $ per MWh produced. In light of this, devising an operation strategy of a generation unit is not influenced by its fixed cost, as these expenses are burdened by the owner whether the units are operated or not. Therefore, only variable O&M costs are taken into consideration in the unit commitment simulation. The variable O&M cost is primarily driven by the fuel cost, which is proportionate to the amount of fuel required to be burned by the unit to generate power.

The fuel requirement varies according to the amount of heat that needs to be injected to the unit to be converted to power, which is predominantly dependent on technology. To illustrate, a simple cycle of GE 9H gas turbine requires a heat input of 7,910 MMBTU to generate a single MWh, while the combined cycle technology allows for a reduction of this heat demand to 5,378 MMBTU for each MWh [29]. Each additional MMBTU of heat required to generate a single MWh translates into fuel consumption and hence additional monetary cost for each MWh generated. Moreover, the fuel price, which varies from one fuel type to another has a significant impact on this cost. Accordingly, the cost function of a certain thermal generation unit can be expressed in terms of its cost per MWh ("incremental cost") as a function of its output. A basic and generic formulation of such cost function is stated in Equation (3.14) and Figure 3.4.

$$Cost\ (P_h) = A \times P_h + B \tag{3.14}$$

Where:

P_h	The generator output at hour h [MW]
A	Generator incremental cost [$/MWh]
B	Generator Cost when generating the minimum output [$]
Pmin	Generator minimum output [MWh]
Pmax	Generator maximum output [MWh]

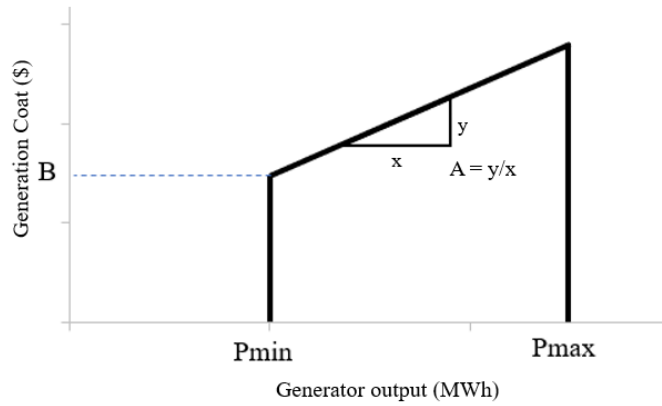


Figure 3.4: Linearized generation unit cost function

Typically, and for a higher level of accuracy, cost functions are represented using second-order equations, which in turn have a parabolic shape. However, a linear function has been used here to explain the underlying concept in a simple manner. Consequently, as the incremental cost varies from one generation technology to another, each generation technology has a different slope. Accordingly, in order to formulate a unit commitment problem for a group of generation units, information about the different curve's slopes are required. For a certain MW demand to be met, the units with the cheapest incremental cost will be operated gradually until it reaches a point where it hits its maximum capacity level or meets the demand. In case the unit reached its maximum capacity prior to meeting the demand, the system operator will be in a need to operate a more expensive unit aiming to meet the demand. The operator continues to carry out this process until the demand is satisfied. At this point, the incremental cost of the generation unit that was operated lastly (most expensive) will represent the price used to charge the end-user. Also, any additional MWh demand will be served by this unit. In other words, this last operated generation unit is considered as the marginal unit and it sets the price of the system within the same vicinity assuming no transmission constraints. In the same manner, the generators are dispatched on an hourly basis to satisfy the demand of the respective hour.

Figure 3.5 exhibits an example of unit commitment optimization applied to three thermal generation units that have different incremental costs. The cheapest unit has an incremental cost of 30 $/MWh, while the other two units have incremental costs of 50 $/MWh and 70 $/MWh. In this case, at a certain hour of the day, the operator is made to supply a demand of 50 MW at the lowest possible cost. Pursuing cost minimization, the cost functions curves of the generators available for dispatch are stacked as shown in Figure 3.5 until the last generation curve intersects with the line specifying the demand. This process is an implementation of a key economics principle, which is the demand-supply balance. Accordingly, the system's balancing price is the incremental cost of the generator that balanced the system, which is 70 $/MWh. Balancing the system's supply and demand for each hour throughout the year at the lowest cost possible is simulated by solving the unit commitment optimization functions.

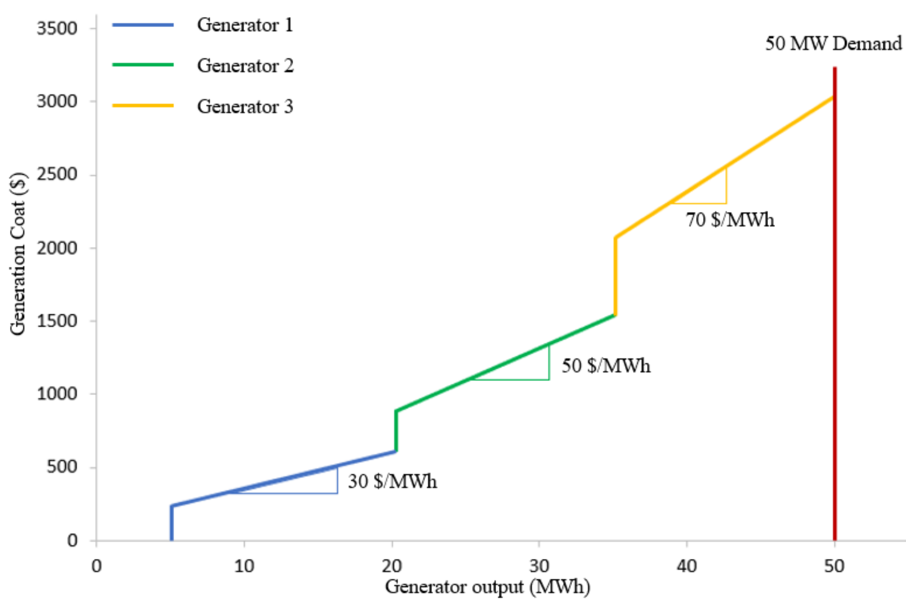


Figure 3.5: System demand-supply balancing

3.4 Simulation Softwares

In order to perform this study, two software programs have been utilized, which are:

1. PLEXOS

PLEXOS is the main software used for this study, which is developed by Energy Exemplar (www.energyexemplar.com). It is a market simulation software developed by Energy Exemplar, that has the capability to model complex and large scale systems. It is featured to solve optimization problems for integrated resources long term and short term planning and unit commitment. PLEXOS's advanced features do not only cover power systems, but also extend to cover water systems and gas systems.

The software is flexible to solve different optimization problems with different optimization engines of the user choice. As the unit commitment is a mixed-integer optimization problem, mixed integer programming (MIP) was adopted via Xpress optimization engine.

2. PVSyst

PVSyst was utilized as a tool to generate the time series of the forecasted output of the PV system. It is a satellite-based software that uses the geographical location information of the sites as input and generate the forecasted output. Also, the software is capable to accommodate multiple technical considerations of the PV systems such as the tilt angle and the inverter size.

Chapter 4: Research Testbed (KSA Power System)

For this study, we are considering KSA's power system as the testbed. KSA's power system data such as generation units' specifications along with historical demand data were used as input to the model built in the software. A brief description of KSA's power system is provided below:

4.1 Generation

To simulate the KSA power system's operation, the system's data for the year 2018 were utilized. The simplified version of the system model consists of 196 generation units with a total maximum capacity of almost 86 GW. In reality, according to the data published by Electricity and Cogeneration Regulatory Authority (ECRA), there are more than 700 licensed generation units within KSA's power system. However, for the sake of minimizing memory and simulation time, they were reduced by aggregating a group of units to represent one unit based on the similarity of technology, fuel type and size. The available generation units vary in terms of technology, as the available technologies are:

1. Combined cycle (CC).
2. Steam turbines (ST).
3. Simple cycle gas turbine (SC).
4. Cogeneration (Cogen), which generates power and steam.
5. Desalination plants (Desal), which generates power and water.

The generation units also vary in terms of the type of fuel burned for their operation as the fuel types used for power generation in KSA are:

1. Crude oil, including Arab Heavy crude (AH) and Arab Light crude (AL)

2. Fuel oil, including heavy fuel oil (HFO)
3. Gas
4. Diesel

Table 4.1 offers a summary of KSA's power generation per region in terms of capacity, technology and fuel.

Table 4.1: Generation in KSA

Region	Total generation capacity (GW)	Common Technology	Common primary fuel type
East	32	CC, ST and Cogen	Gas
Central	19	CC and SC	Gas and crude oil
West	29	CC, SC and Desal	Crude oil and fuel oil
South	6	SC and ST	Crude oil, fuel oil, and diesel

4.2 Transmission

The Base case of the simplified model of KSA's power system consists of six nodes, that are interconnected as depicted in Figure 3.3.

4.3 Demand-side

The hourly demand of each of the above-listed areas are used for the system operation simulation. Table 4.2 shows that demand information for KSA's areas in the year 2018:

Table 4.2: Energy demand per sector in KSA's areas

	GWh						
Region	**Residential**	**Commercial**	**Government**	**Industrial**	**Others**	**Total**	**Peak (GW)**
COA	43,044	15,992	15,672	6,428	4,223	**85,359**	19.80
EOA	25,193	8,981	8,682	36,754	4,273	**83,883**	18.60
WOA	46,272	16,966	13,338	14,299	10,285	**101,160**	16.70
SOA	15,918	4,910	6,218	696	1,043	**28,785**	5.60

The shares of the residential and industrial customers from the energy demand in each area are as outlined in Table 4.3:

Table 4.3: Residential and Industrial shares in KSA's areas

Region	**Residential**	**Industrial**
COA	50%	8%
EOA	30%	44%
WOA	46%	14%
SOA	55%	2%

4.4 VPP Design

For the purpose of exploring the economic feasibility of integrating renewable energy resources through VPPs over the different areas of KSA, we are using a standard size of VPPs that is also reflective of the demand nature of each area. Considering a minimum PV size of 30 MW for the VPP to integrate into the grid, the VPPs of each area have been designed to have a peak demand that can be met by the 30-MW PV. The time series outputs of the PV system installed in each area have been created with the aid of the PVSyst software. In order to account for the losses associated with DC-AC conversion and to optimize the size and cost of the inverters, the software generates PV output with chopping factors in the range of 1.3 – 1.4. This leads to the fact the maximum output yields from the PV systems do not reach the maximum capacity of the installed system. In turn, the maximum AC power output from the system is 71% (1/1.4) of the capacity, as shown in Figure 4.1, that shows the output of a 1-MW PV system during the day encompasses the peak hour.

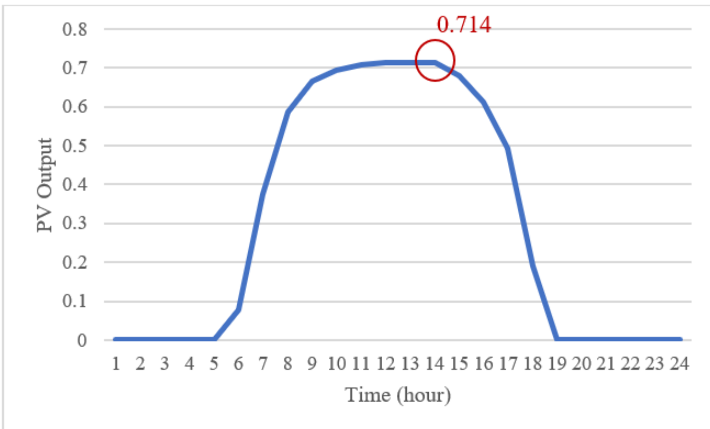


Figure 4.1: 1-MW PV system output for a sample day

Accordingly, for a 30-MW PV system, the maximum output is 21 MW, which is the size used to design the load of the VPP associated with the PV along with the typical residential/industrial load profiles and the demand characteristics of the VPPs' respective areas.

Chapter 5: Results and Discussion

5.1 Case 1: Individual DER

In this section, we consider the case of individual DERs with each have a PV supporting its load. Due to the size limitation of these DERs, they have no access to the grid, which means that they are not able to export energy to the grid in case of any PV output that is in excess of the demand. The number of DERs in a VPP and their peak demand are assumed to be as per Table 5.1:

Table 5.1: VPP Components

VPP	No. DERs	Peak load of each DER (MW)	PV size of each DER (MW)
EOA VPP	5	4.2	6
COA VPP	5	4.2	6
WOA VPP	3	6.93	10
SOA VPP	4	5.25	7.5

Under this case, the study examined the cost of energy of those DERs, defined as the cost to serve each MWh demand in the VPP's DERs. The cost of energy in the case, where the DERs relies solely on the grid supply, higher than the case when it has in-house generation through PV. The cost of the energy supplied from the grid relies upon the cost of operating the thermal power plants to serve the additional MWh demand. As far as the PV cost is concerned, as we are exploring the economic feasibility of installing the PVs, the PV Levelized Cost of Energy is utilized as the PV's cost in simulating the operation of the system. This will ensure the reflection of both the investment and operational cost of the PV. Accordingly, unit commitment of the system, will be a trade-off between grid energy price and the PV's LCOE, which then provide an insight on whether or not it is economically feasible to invest in building a PV of the DER in view of the existing system cost.

As the fuel cost is a key factor contributing to the system's price while being heavily subsidized in KSA, we are running sensitivity analyses around the fuel prices considering the scenarios tabulated in Table 5.2.

Table 5.2: Fuel Prices

Fuel Price Scenario	Gas ($/MMBTU)	AL ($/BBL)	AH ($/BBL)	HFO ($/BBL)	Diesel ($/BBL)
Domestic	1.25	6.35	4.4	4.4	14
Partial Subsidy	2	39	33	29	55
International	2.75	71	66	74	100

The domestic fuel prices are the prices currently used for utilities as reported in the study published by the Oxford Institute of Energy Studies [30]. On the other hand, the international fuel prices as sourced from the fuel outlook issued by Energy Information Agency (EIA) [31] and they include no subsidy. The partially subsidized prices are assumed to fall between the two fuel prices sets (i.e. subsidized and international) in order to explore the impact of gradually removing the fuel subsidies. As an input to the simulation software, we consider unified fuel prices in terms of $/MMBTU. The above per barrel fuel prices were converted into $/MMBTU. The fuel prices of the different fuel types over the three pricing scenarios are depicted in Figure 5.1 below:

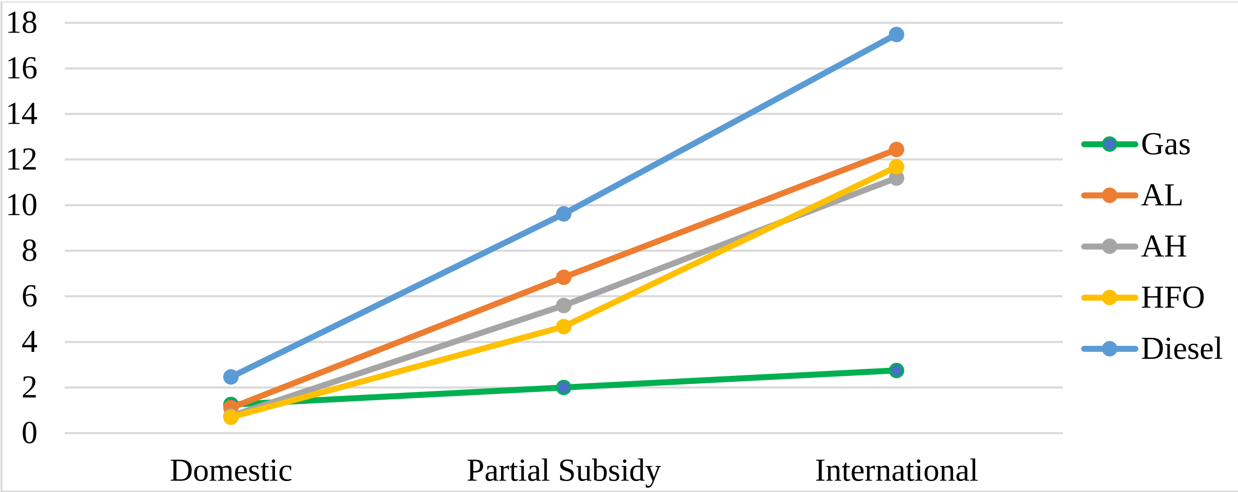


Figure 5.1: Fuel Prices ($/MMBTU) for different pricing scenarios

The cost of energy for DERs considered in this study under each fuel prices scenario are discussed as follows:

5.1.1 Domestic Fuel Prices:

The overall system cost minimization was simulated in PLEXOS in case the DERs have no generation and in the case where they have generation from PV. Sample snapshots that show an eight-day summer period (July 15 – July 22) of EOA VPP demand and the source of energy by which the demand is met are presented in Figure 5.2 - Figure 5..

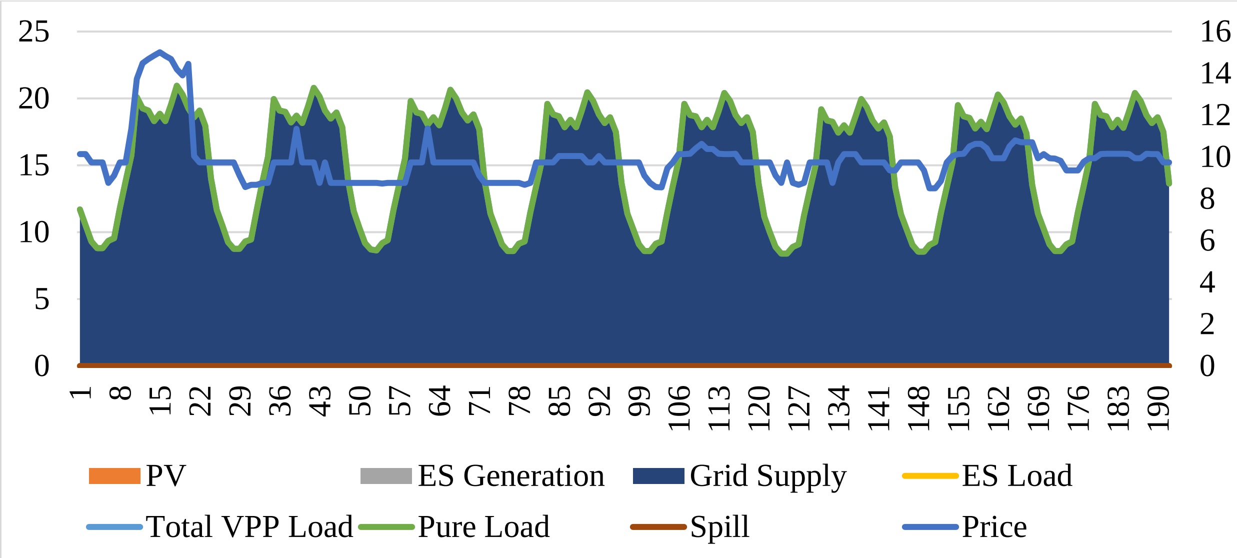


Figure 5.2: EOA VPP Demand and Supply - 0 MW PV installed

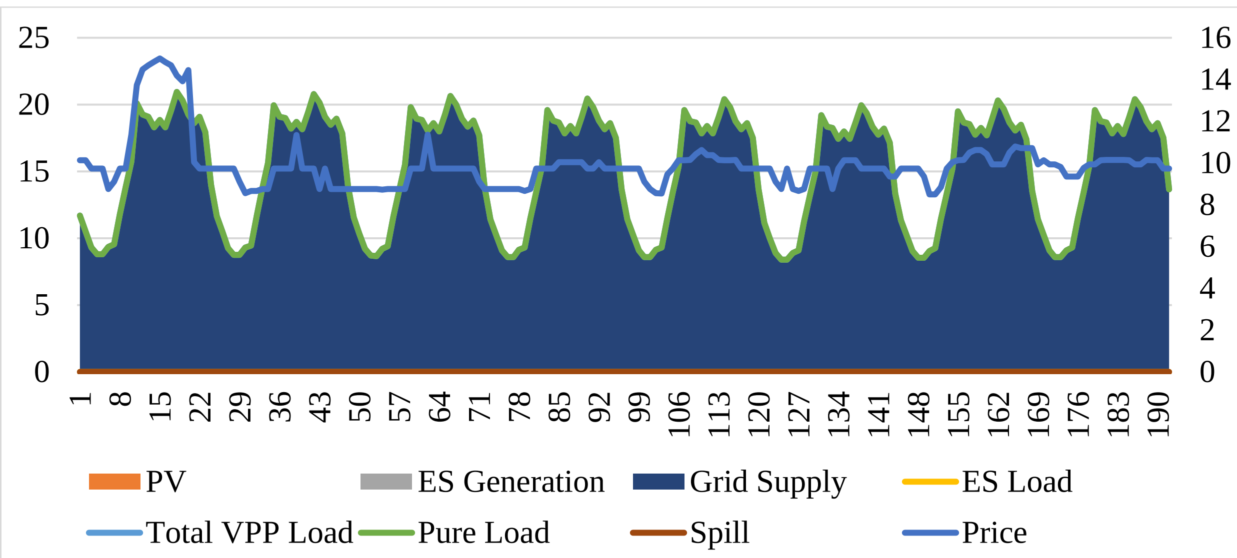


Figure 5.3: EOA VPP Demand and Supply - 30 MW PV installed

As shown in the above snapshots, when the DERs have PV installed, there is no generation from the PV. In other words, the installed PV units do not contribute to meeting the DERs' demand. This is applicable for all the other VPPs. As the PV LCOE is considered as the operational cost of the PV for the simulation purpose, these results lead to a conclusion that given the system's prices, which reflects the domestic (subsidized) fuel prices, it is not feasible to invest in installing PV for the DERs.

Accordingly, with the current prices, the VPPs' DERs are always supplied with energy from the grid. The average cost of energy for the DERs of each VPP when DERs rely on grid supply and when they have PV installed are shown in Table 5.3.

Table 5.3: VPP cost of energy under domestic fuel prices

Cost of Energy ($/MWh)				
Scenario	**EOA VPP**	**COA VPP**	**WOA VPP**	**SOA VPP**
0 MW PV	8.34	10.08	10.30	10.70
30 MW PV per VPP	8.34	10.08	10.30	10.70

The results show that with the current fuel prices, the cost of energy is the same in both scenarios. These costs of energy represent the system's prices at each area under the domestic fuel prices. The systems price in EOA is the lowest as compared to the other areas, which is mainly due to adopting generation technologies of higher efficiencies in the east area of KSA (e.g. CC, cogeneration, desalination).

5.1.2 Partially subsidized Fuel Prices

In this case, we run the same simulation of the system's operation with no PV installed in one case and a total of 30 MW PV installed per VPP broken down per DERs as per Table 5.1. However, in this case, we are considering the partially subsidized fuel prices as per Table 5.2. The demand and supply stacked charts for an eight-day summer snapshot when there is no PV installed are shown in Figure 5. - Figure 5..

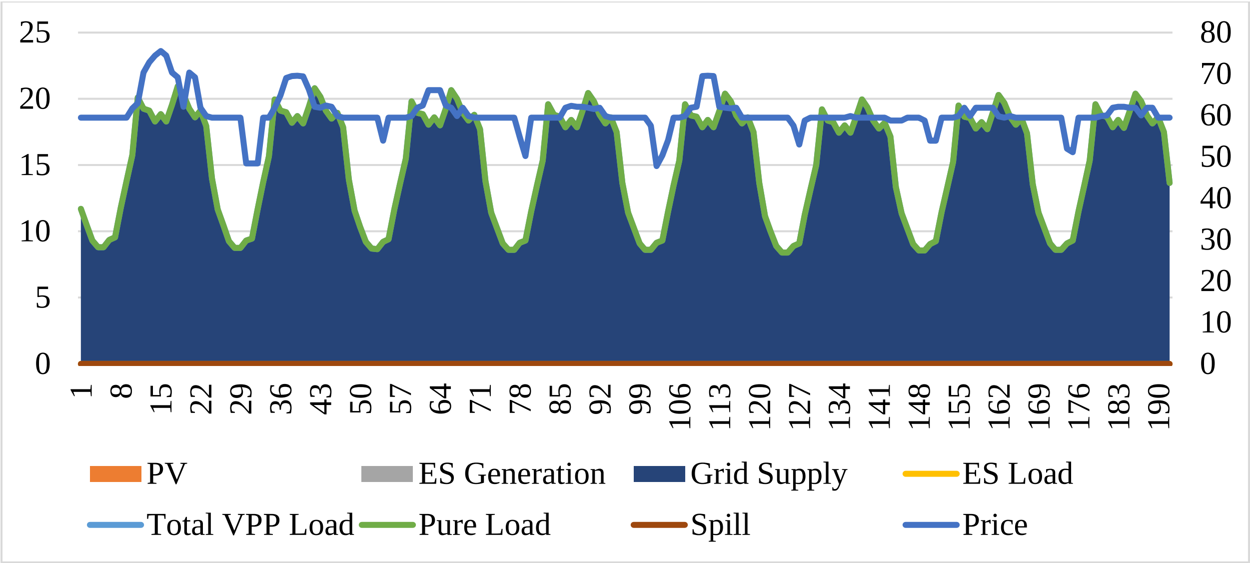


Figure 5.4: EOA VPP Demand and Supply - 0 MW PV installed

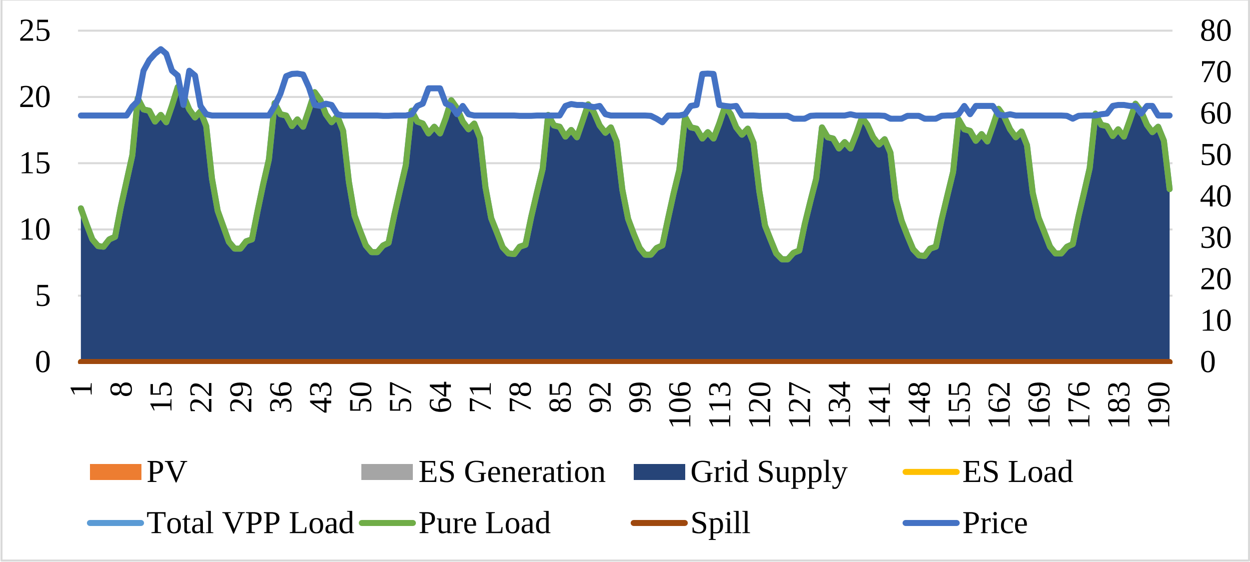


Figure 5.5: COA VPP Demand and Supply - 0 MW PV installed

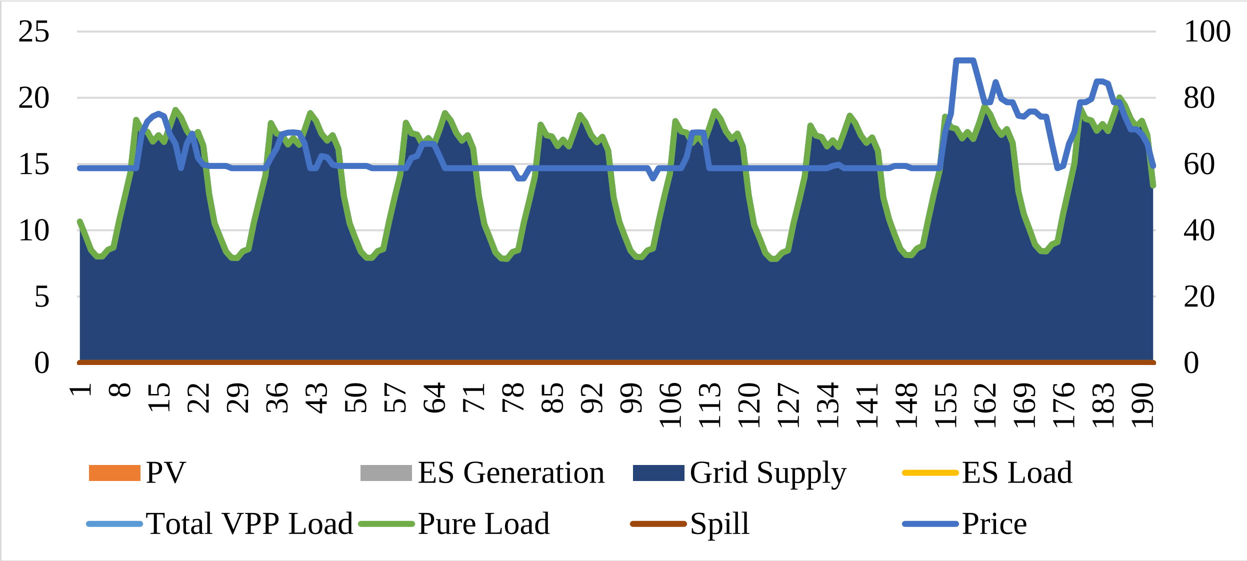


Figure 5.6: WOA VPP Demand and Supply - 0 MW PV installed

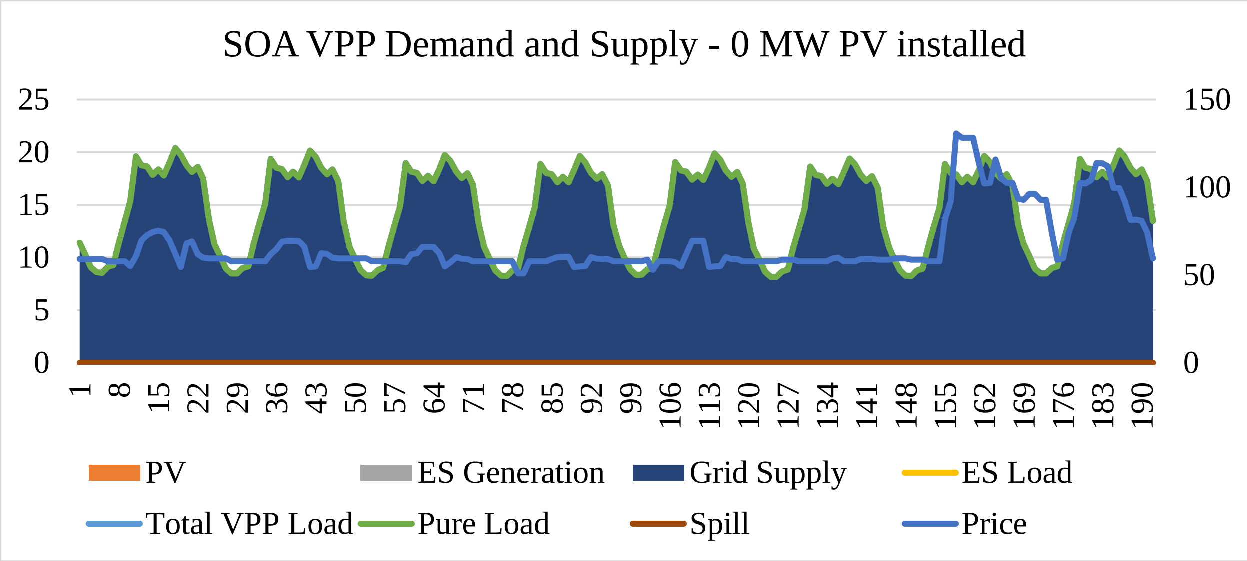


Figure 5.7: SOA VPP Demand and Supply - 0 MW PV installed

According to the simulation results, with the partially subsidized set of fuel prices, the system's prices of area as shown in Table 5.4:

Table 5.4: System's prices under partially subsidized prices

System's Price ($/MWh) Partially Subsidized Fuel Prices				
	EOA	**COA**	**WOA**	**SOA**
Minimum	18.07	18.07	28.95	41.76
Maximum	83.02	83.02	116.84	172.71
Average	36.12	38.65	53.57	72.77

Given the above-tabulated system's prices, it can be expected the VPP's DERs are expected to witness contribution from the PV to serve their demands. This speculation is justified by the fact that PV LCOE used in the simulation is 25 $/MWh, while the system's prices area averaging between 36.12 $/MWh and 72.77 $/MWh with maximum prices reaching 172.71 $/MWh in SOA and minimum prices of 18.07 $/MWh for EOA and COA. Consequently, during the optimization process, in the cases where the system's prices seen by each VPP are higher than the PV LCOE (25 $/MWh), it will be more economic to serve the demand through the VPP. The demand and supply snapshots of each area's VPP when a total of 30 MW PV is installed in each VPP with the breakdown shown in Table 5.1 are shown in Figure 5. - Figure 5..

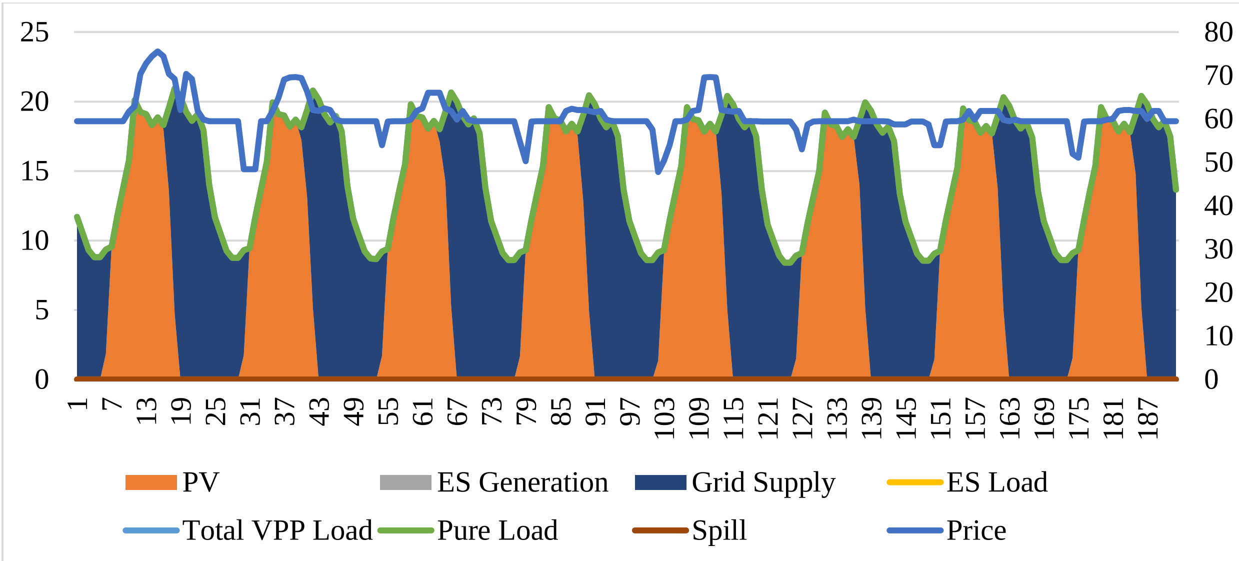


Figure 5.8: EOA VPP Demand and Supply - 30 MW PV installed

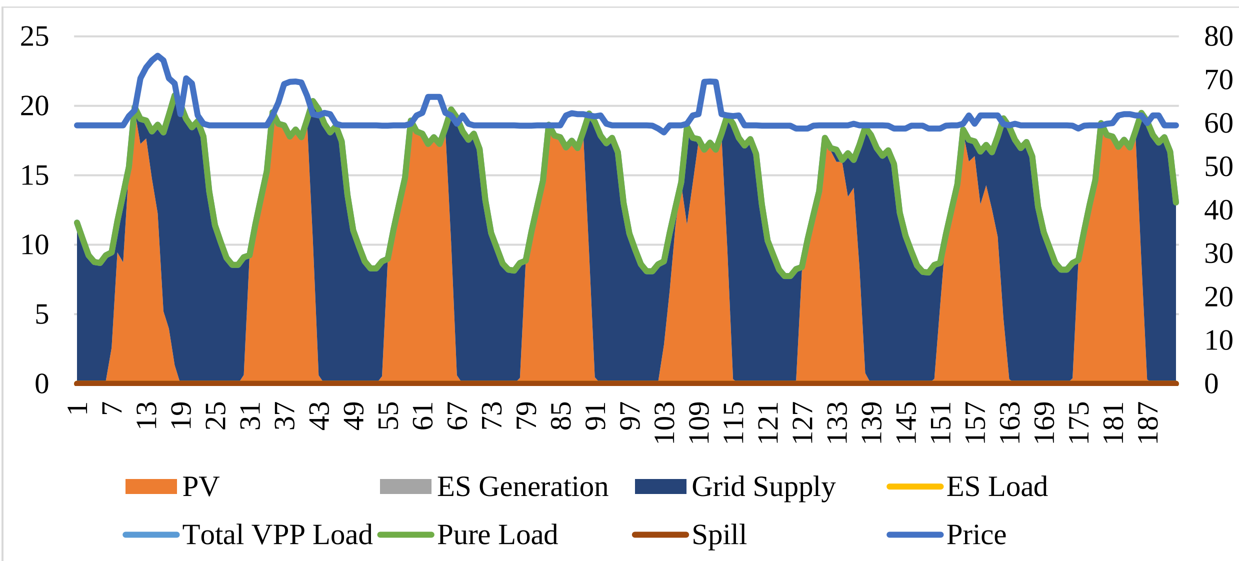


Figure 5.9: COA VPP Demand and Supply - 30 MW PV installed

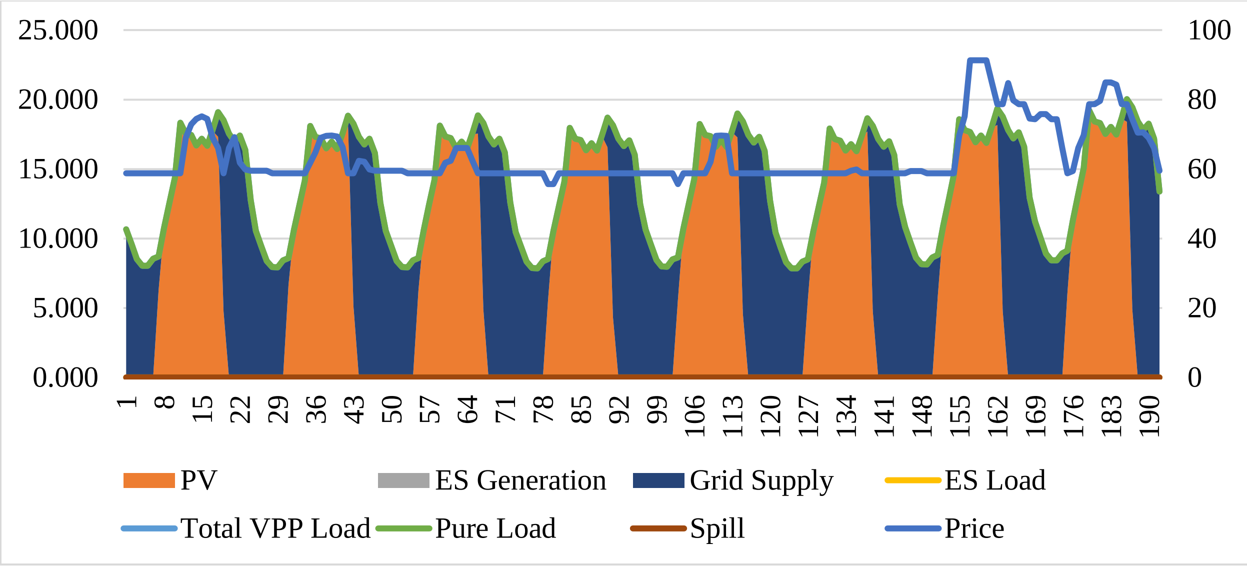


Figure 5.10: WOA VPP Demand and Supply - 30 MW PV installed

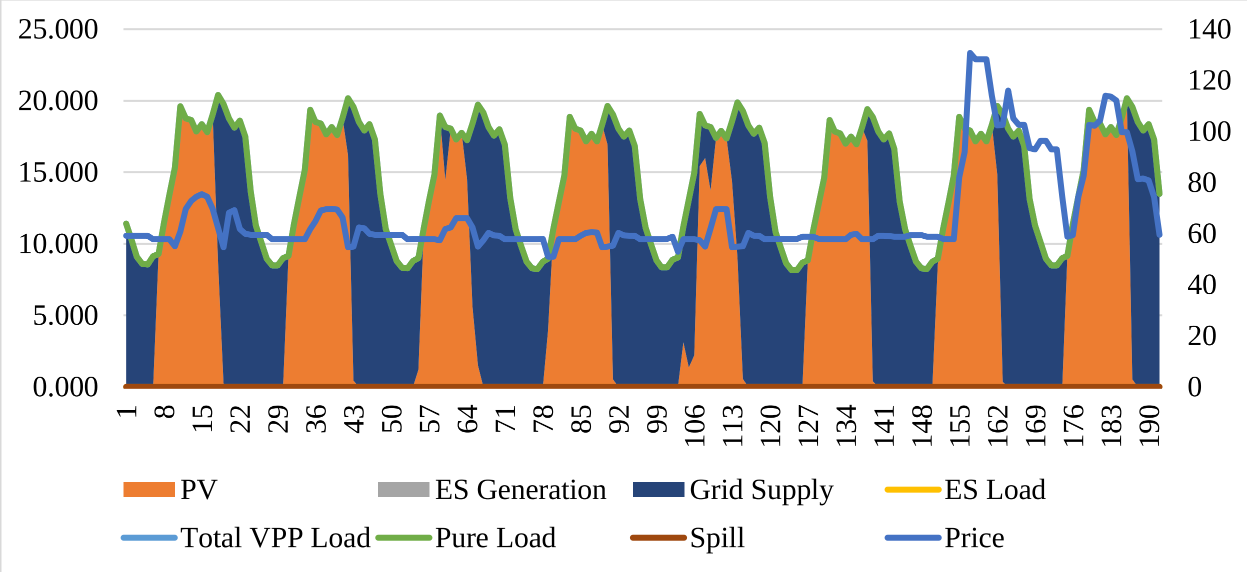


Figure 5.11: SOA VPP Demand and Supply - 30 MW PV installed

The contribution from the PV indicates that at that point in time, given the current system's prices, the PV investment is feasible. The economic parameters and energy generated from PV in the DERs in each VPP in both cases of PV availability under the partially subsidized fuel prices are summarized in Table 5.5 and Table 5.6.

Table 5.5: Results of VPPs without PV - Partial Subsidy

0 MW PV Installed - Partially Subsidized Fuel Prices				
Parameter	**EOA**	**COA**	**WOA**	**SOA**
PV Generation (MWh)	0	0	0	0
VPP Load (MWh)	112,661.95	94,843.70	105,930.57	112,080.80
VPP DERs Net Position ($)	(4,437,464)	(4,241,503)	(5,965,920)	(8,241,621)
Cost of Energy ($/MWh)	39.39	44.72	56.32	73.53

Table 5.6: Results of VPPs with 30 MW PV - Partial Subsidy

30 MW PV Installed – Partially Subsidized Fuel Prices				
	EOA	**COA**	**WOA**	**SOA**
PV Generation (MWh)	28,406.19	27,711.58	53,613.57	57,228.42
VPP Load (MWh)	112,661.95	94,843.70	105,930.57	112,080.80
VPP DERs Net Position ($)	(3,483,414)	(3,244,554)	(4,234,203)	(5,486,458)
Cost of Energy ($/MWh)	30.92	34.21	39.97	48.95

The VPP DERs recognize considerable benefits by installing PV. The value-added of installing a PV is manifested in the reduction of the VPP net financial position and accordingly the reduced cost of energy. These benefits are quantified in Table 5.7.

Table 5.7: VPPs' benefit - Partial subsidy

Parameter	EOA	COA	WOA	SOA
Cost of Energy reduction (%)	21%	24%	29%	33%
VPP DERs' Saving ($)	954,049	996,945	1,731,717	2,755,163

It can be noticed that the highest benefit yield from installing the PV is recognized as the VPP DERs in SOA, as the cost of energy reduced by 33% and the saving is $ 2.7 million. This is attributed to the fact that SOA's system prices are the highest among the other areas as discussed in Table 5.7, where SOA's average price is 72.7 $/MWh and the maximum price is 172.7 $/MWh. This results in higher contribution from PV as they are favorable over the grid energy more frequently than in the other areas.

5.1.3 International Fuel Prices

When the operation is simulated considering the international fuel prices, the operational profile of all VPP in the case when there is no PV installed for the DERs is similar to the profiles when domestic and partially subsidized fuel prices are considered. Thus, the snapshots of the VPP's profiles shown in Figure 5. to Figure 5. are applicable to this case except for the system's prices, where the fuel prices are embedded. Therefore, the financial positions of the VPP's DERs are impacted by the fuel prices. So, under the international fuel prices, the system's prices are summarized with the information tabulated in Table 5.8.

Table 5.8: System's prices under international fuel prices

System's Price ($/MWh) International Fuel Prices				
	EOA	**COA**	**WOA**	**SOA**
Minimum	23.58	23.58	75.74	107.03
Maximum	175.58	175.58	196.17	228.92
Average	65.23	70.01	118.2	175.46

The system's prices in WOA and SOA are higher than those of EOA and COA, due to the fact that power generation in these areas relies heavily on burning crude oil and fuel oil, which are internationally priced significantly higher than gas, as shown in Figure 5.. In light of these system's prices, system optimization is performed and hence the contribution of the PV to serving the VPP's DERs' demand is determined. Figure 5. to Figure 5. illustrate by means of snapshots of an eight-day summer period supply and demand of the VPPs.

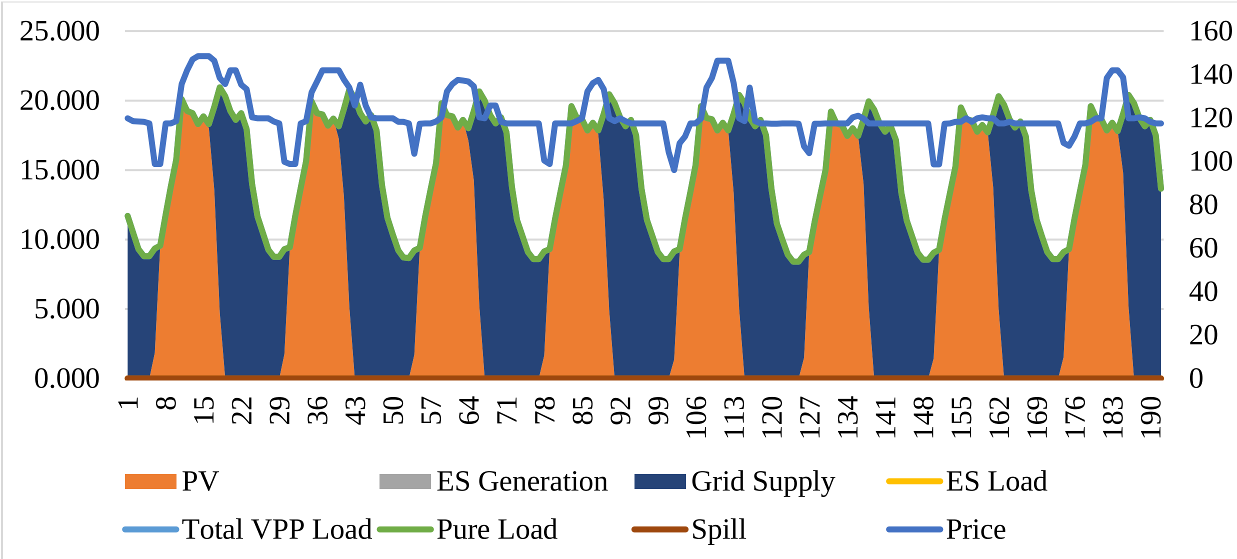


Figure 5.12: EOA VPP Demand and Supply - 30 MW PV installed

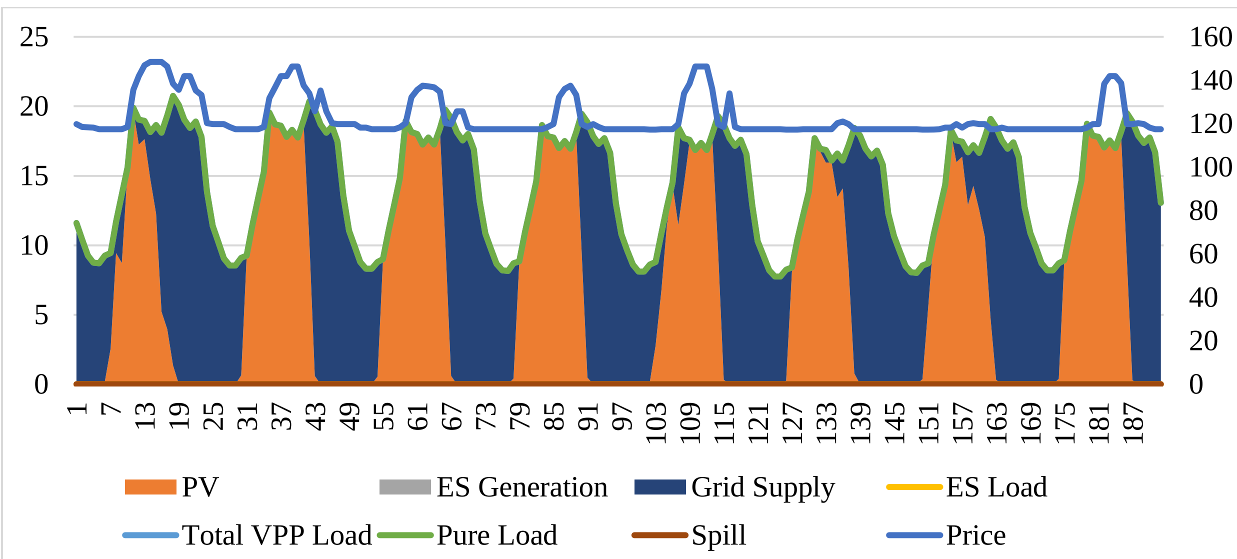


Figure 5.13: COA VPP Demand and Supply - 30 MW PV installed

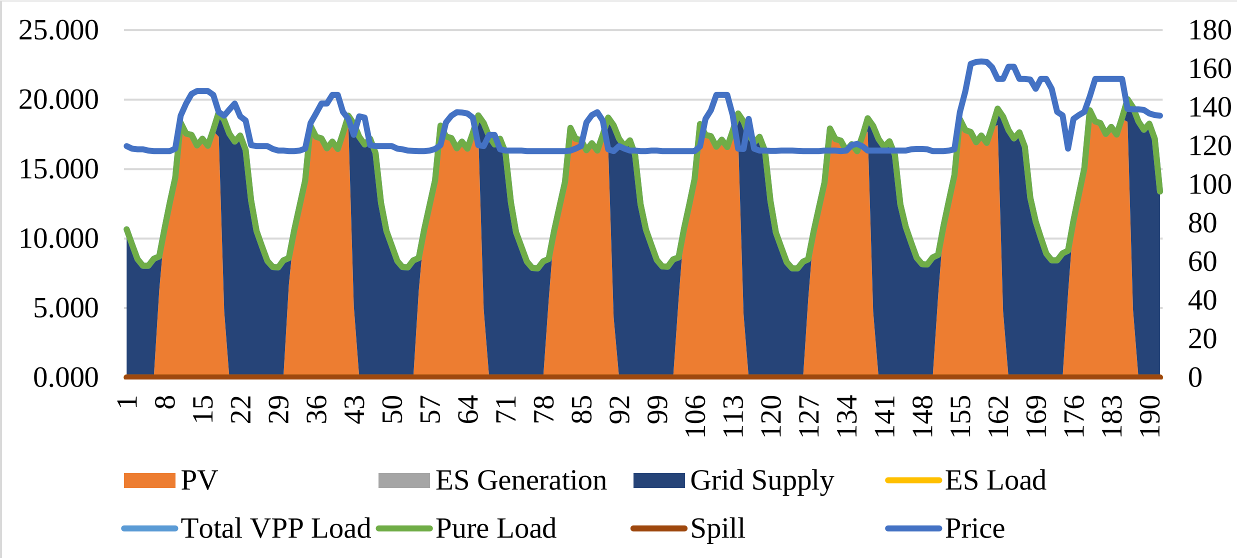


Figure 5.14: WOA VPP Demand and Supply - 30 MW PV installed

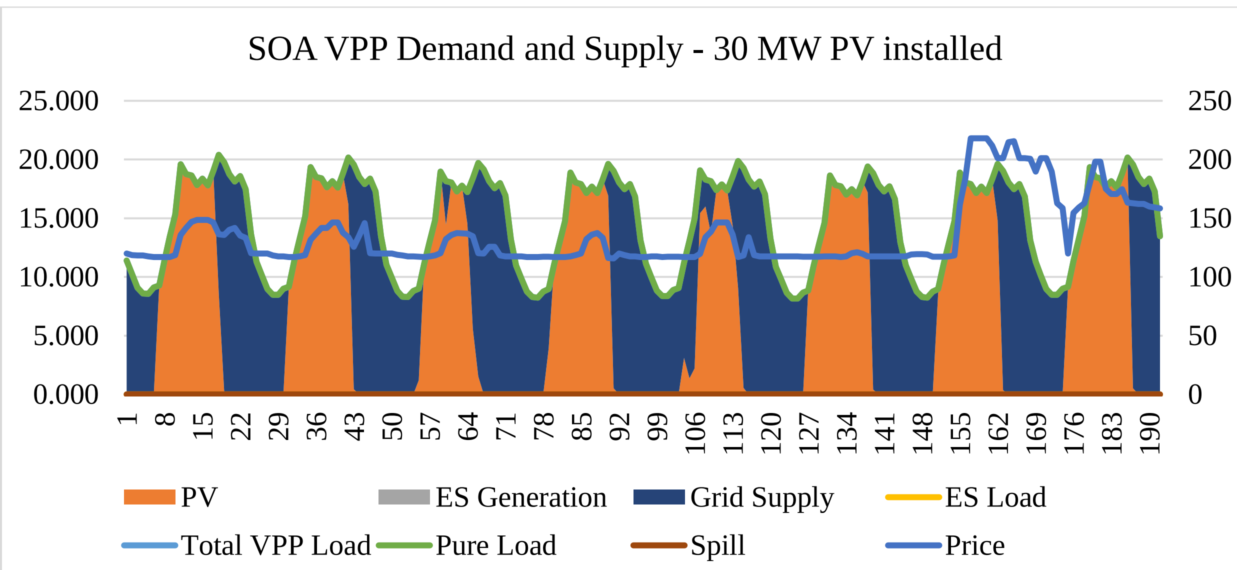


Figure 5.15: SOA VPP Demand and Supply - 30 MW PV installed

As portraited in Figure 5. to Figure 5., the installed PV in the DERs have a substantial contribution to meeting the VPPs DERs demand. Since the optimization resulted in this contribution of the PV, having this PV in place to supply the demand when they are available is more economic than supplying demand from the grid. The VPPs' financial parameters during the availability and the unavailability of PV are presented in Table 5.9 and Table 5.10 along with the amount of energy generated to serve the demand:

Table 5.9: VPPs results without PV – International Fuel Prices

0 MW PV installed – International Fuel Prices				
	EOA	**COA**	**WOA**	**SOA**
PV Generation (MWh)	0	0	0	0
VPP Load (MWh)	112,661.95	94,843.70	105,930.57	112,080.80
VPP DER Net Position ($)	(8,206,009)	(7,981,582)	(12,896,702)	(19,419,155)
Cost of Energy ($/MWh)	72.84	84.16	121.75	173.26

Table 5.10: VPPs results with 30 MW PV - international fuel prices

30 MW PV installed – International Fuel Prices				
	EOA	**COA**	**WOA**	**SOA**
PV Generation (MWh)	45,283.10	27,711.58	53,613.57	57,228.42
VPP Load (MWh)	112,661.95	94,843.70	105,930.57	112,080.80
VPP DER Net Position ($)	(5,632,303)	(5,306,381)	(7,626,435)	(11,083,363)
Cost of Energy ($/MWh)	49.99	55.95	71.99	98.89

The energy generated from the PV units are the same as those found in the case of partially subsidized fuel prices for all areas VPPs except for those in EOA. This is attributed to EOA's system's price when considering partial subsidy for fuel, which has an average that is lower than the average prices of COA, WOA, and SOA. In the case of international fuel prices, the system's price in EOA came to be higher, which makes the generation from PV more economic than the grid supply. The fact that the PV generation in the international fuel price and partial subsidy prices cases are the same for COA, WOA and SOA indicates that PV units in those areas reach their constraint of meeting the demand only with no access for export to the grid at the partially subsidized prices. It is inferred from Table 5.9 and Table 5.10 that the PV contribution translates into a positive financial impact on the VPPs' DERs, which are clearly reflected on the improved aggregated net financial position of the VPPs and the lower cost of energy. The positive impacts of the PV generation on the VPPs' financial parameters are summarized in Table 5.11.

Table 5.11: VPP benefit - International Fuel Prices

Parameter	**EOA**	**COA**	**WOA**	**SOA**
Cost of Energy reduction (%)	31%	34%	41%	43%
VPP DERs' Saving ($)	2,573,706	2,675,202	5,270,267	8,335,791

The financial benefits reveal that VPP in SOA recognizes the highest financial benefit of installing PV as compared to the VPP's of the other areas. This is clearly reflected in the 43% reduction in the cost of energy and the saving of $ 8.3 MM, which are higher than the other areas. This is explained by the fact that the energy generated by the PV in SOA displaces the energy generated by thermal generation units in that area, which comes at a cost higher than that of the other areas due to consuming more expensive fuel types.

5.2 Case 2 Simulation results

In this case, we assumed that the DERs of each VPP aggregate together to act as one single entity when it comes to the interface with the grid. This aggregation brings a total of 30 MW PV installed for each VPP, by which the VPPs have access to the grid to export energy to the grid. Such access does not exist when the DERs act individually due to their size limitation, as discussed in case 1. In the previous case, the optimization objective was to minimize the overall system cost, while considering availing PV for the DERs. However, in this case, as the DERs aggregate together and become visible to the grid as VPPs, we will investigate the profitability of each VPP. So, the optimization objective is to maximize the profit of the VPP through maximizing the revenue from its resources' generation while minimizing the operational cost of the of the VPP, which is represented in this study by the LCOE and LCOS for the PV and energy storage systems, respectively. So, this profit maximization objective function is simulated for the VPPs over the different areas to identify which area is more attractive for VPPs where they can make higher profits. For this exercise, we ran a sensitivity around the size of the PV as we considered the 30-MW size as the base and assessed the profitability for other sizes of 20% less than the base (24 MW) and 20% higher than the base (36 MW). The assessment of the profitability of each area's VPP is performed through a common comparison indicator, which is the normalized benefit per unit of energy generated from the VPP. The normalized benefit is defined as the ratio between the VPP's saving and its generated energy, formulated shown below in Equation (5.1):

$$\frac{VPP's\ Net\ Position_{base\ case} - VPP's\ Net\ Position_{PV}}{VPP\ MWh\ generated} \quad (5.1)$$

This indicator offers a comparison metric between the VPPs' benefits resulted from installing PV in the different areas, while eliminating the impact of the PV size, which makes it a common base between the different areas. Accordingly, the factors that impact this comparison indicator are the radiation levels in the different areas as well as the system's price of each area, which reflects the price of the fuel type burned and the efficiency of the thermal generators technologies in place.

Similar to Case 1, the study was performed the VPPs in the different areas considering the three sets of fuel prices as follows:

5.2.1 Domestic fuel prices

As discussed in section 5.1.1, the system's prices associated with the domestic fuel prices make the investment in PV unfeasible. Therefore, when simulating the operation of VPP, the PV units have no contribution to the demand. Accordingly, there is no benefit recognized from installing the PV units, as it is always more economic for the VPP to supply its demand from the grid rather than the PV. Accordingly, the cost of energy for the VPPs are the same as those outlined in Table 5.12.

Table 5.12: VPPs cost of energy under domestic fuel prices

	EOA VPP	COA VPP	WOA VPP	SOA VPP
Cost of Energy ($/MWh)	8.34	10.08	10.3	10.7

5.2.2 Partially subsidized fuel prices

Given the system's prices coupled with the partially subsidized fuel prices, Table 5.13 shows the VPP's financial parameters when there is no PV installed within their DERs.

Table 5.13: Case 2 VPP results without PV - Partial subsidy

0 MW PV Installed - Partially Subsidized Fuel Prices				
	EOA	**COA**	**WOA**	**SOA**
PV Generation (MWh)	0	0	0	0
VPP Load (MWh)	112,661.95	94,843.70	105,930.57	112,080.80
VPP DERs Net Position ($)	(4,437,464)	(4,241,503)	(5,965,920)	(8,241,621)
Cost of Energy ($/MWh)	39.39	44.72	56.32	73.53

When PV units are made available in the VPPs, it is expected that they will have a contribution to the demand, as addressed in Case 1 under the same set of fuel prices. However, the PV generation, in this case, is expected to be more, as the VPPs here have access to the grid, by which they are able to export the PV's generation that is in excess of the VPPs' demand to the grid.

Figure 5.1 to Figure 5.8 provide snapshots of the demand and supply to the of the VPPs over the different areas with three scenarios of PV sizes in each area (24 MW, 30 MW and 36 MW).

- EOA VPP

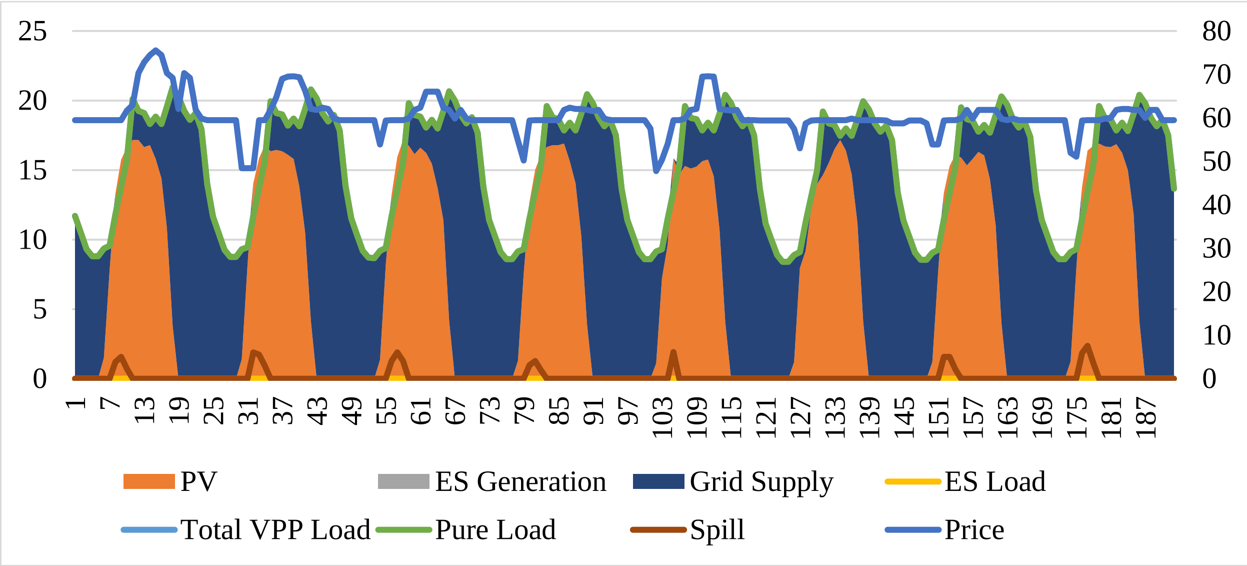


Figure 5.1: EOA VPP Demand and Supply - 24 MW PV installed

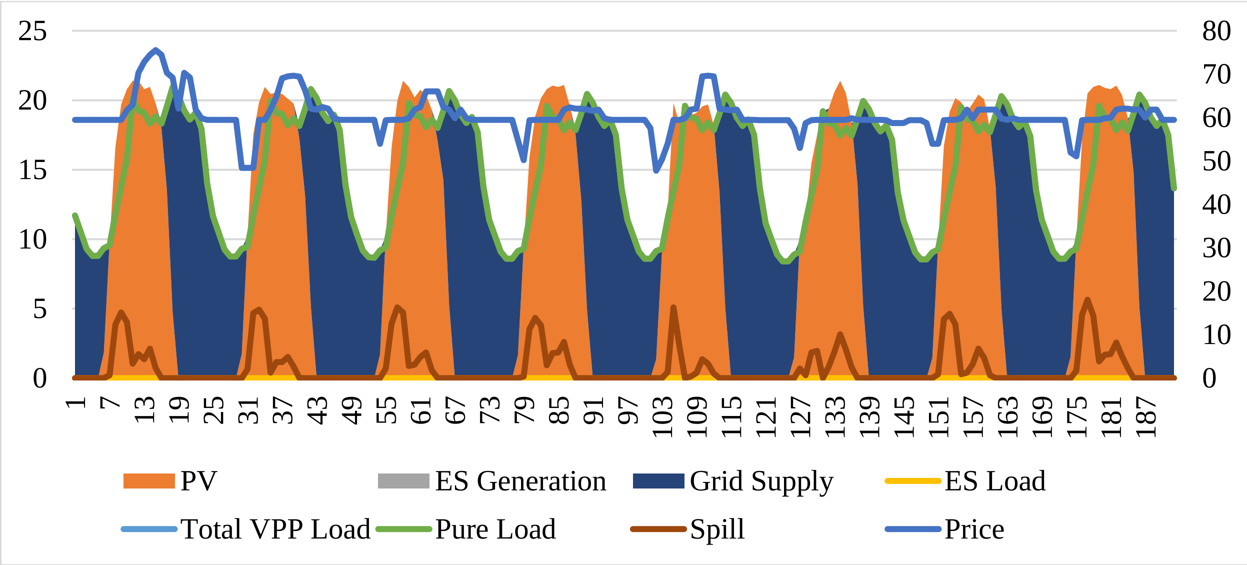


Figure 5.17: EOA VPP Demand and Supply - 30 MW PV installed

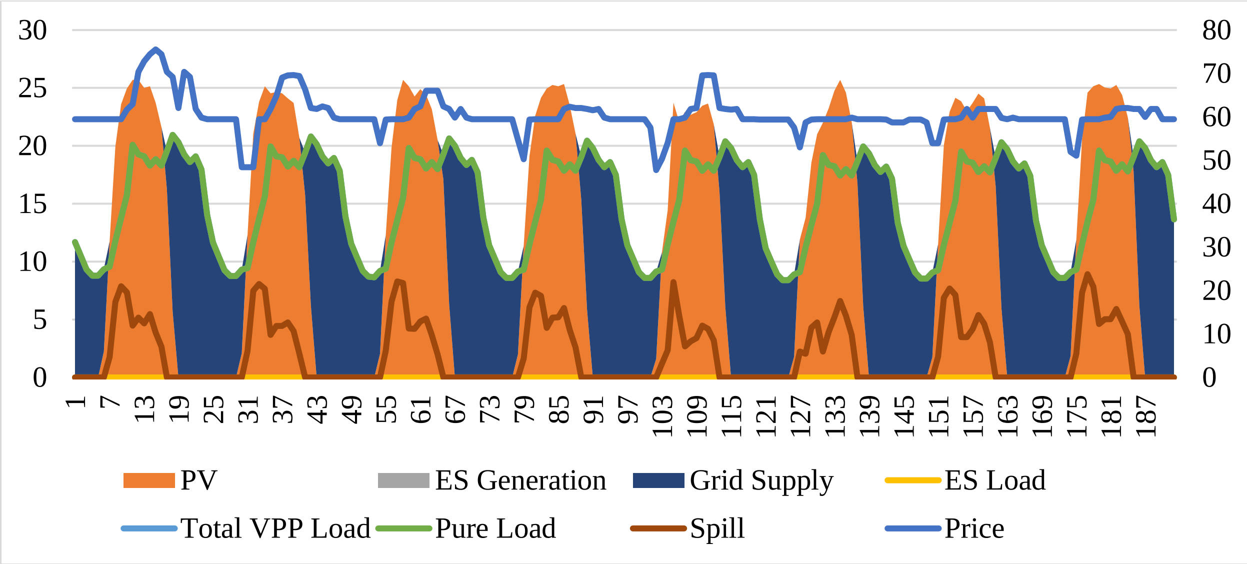


Figure 5.2: EOA VPP Demand and Supply - 36 MW PV installed

- COA VPP:

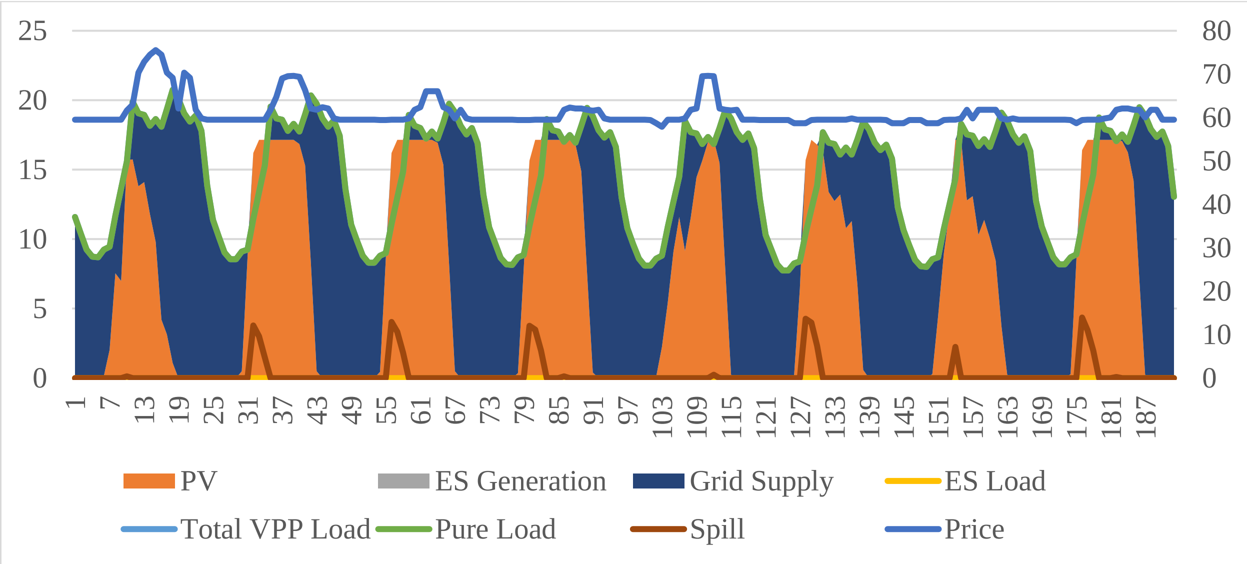


Figure 5.3: COA VPP Demand and Supply - 24 MW PV installed

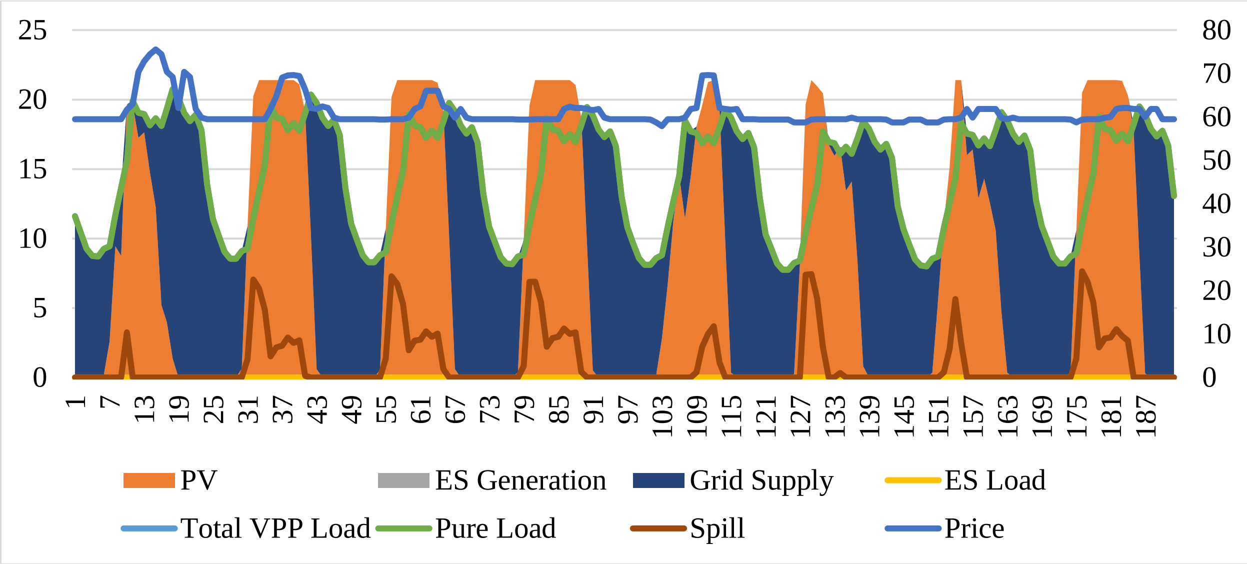


Figure 5.20: COA VPP Demand and Supply - 30 MW PV installed

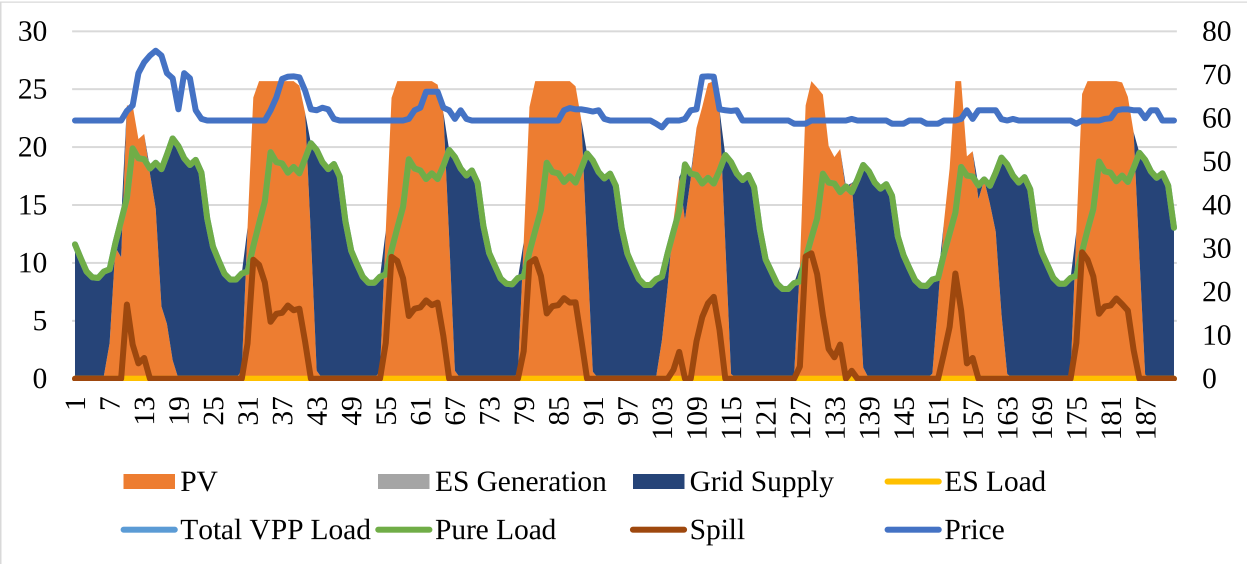


Figure 5.21: COA VPP Demand and Supply - 36 MW PV installed

- WOA

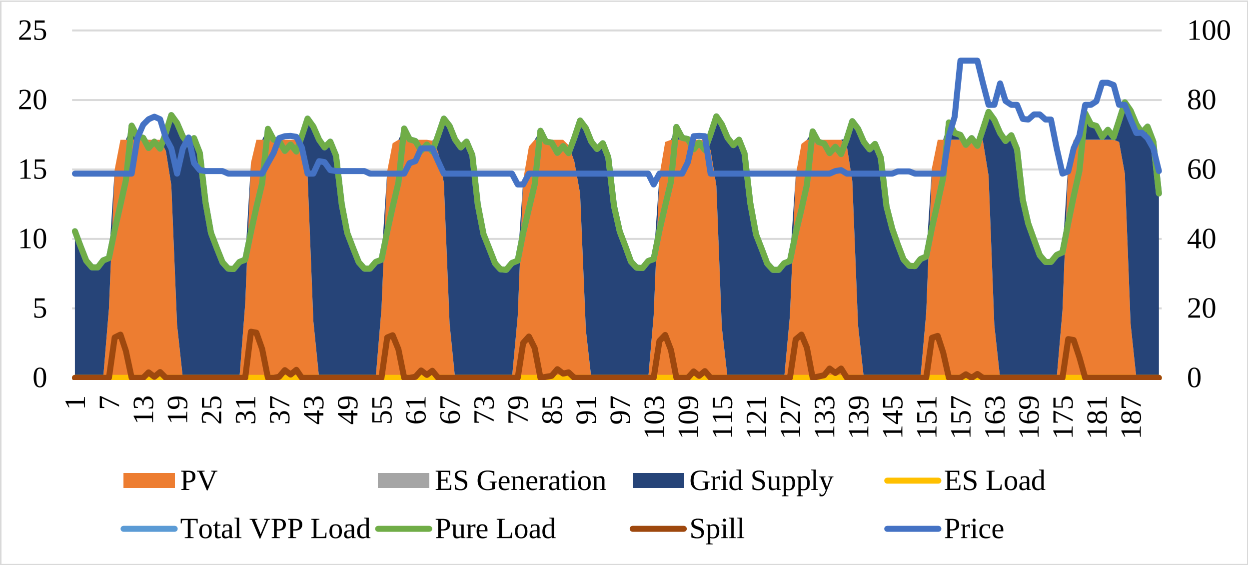


Figure 5.22: WOA VPP Demand and Supply - 24 MW PV installed

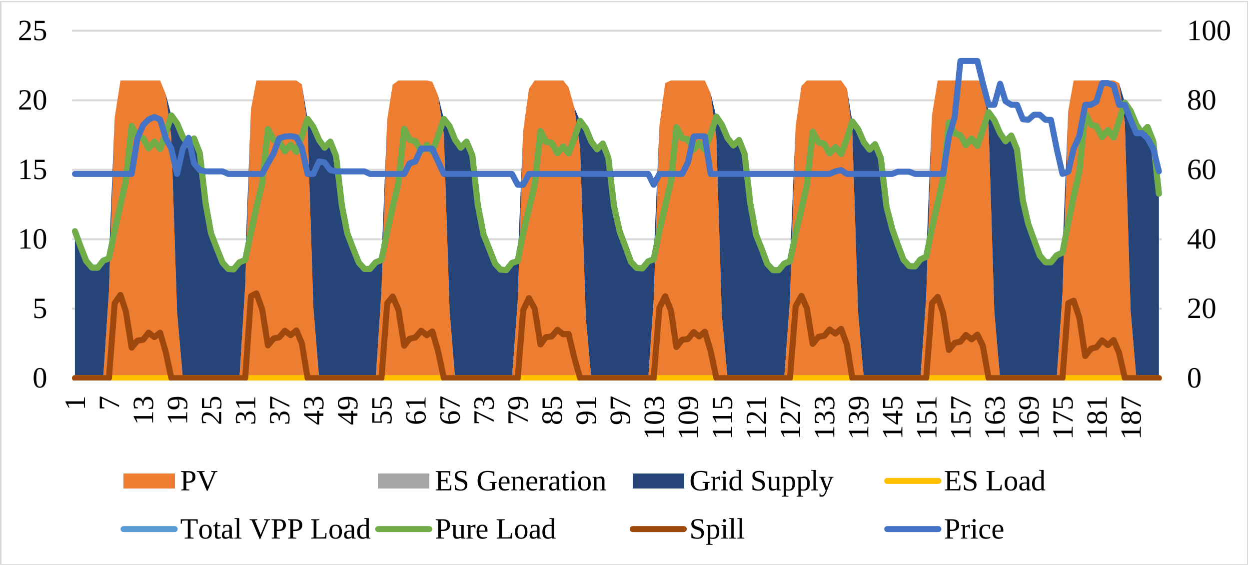


Figure 5.4: WOA VPP Demand and Supply - 30 MW PV installed

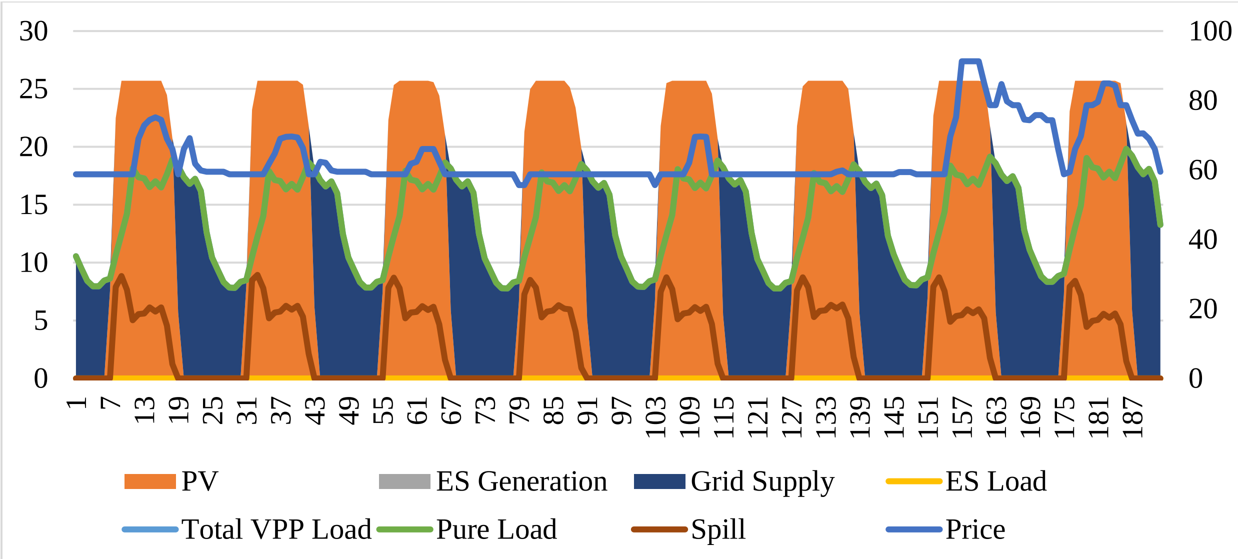


Figure 5.5: WOA VPP Demand and Supply - 36 MW PV installed

- SOA

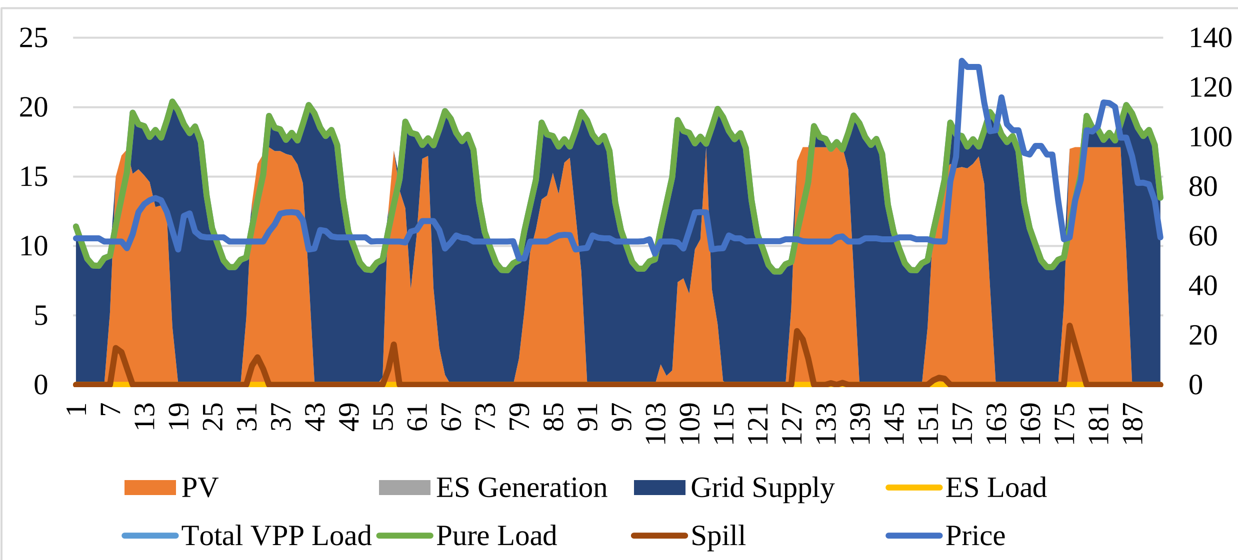


Figure 5.6: SOA VPP Demand and Supply - 24 MW PV installed

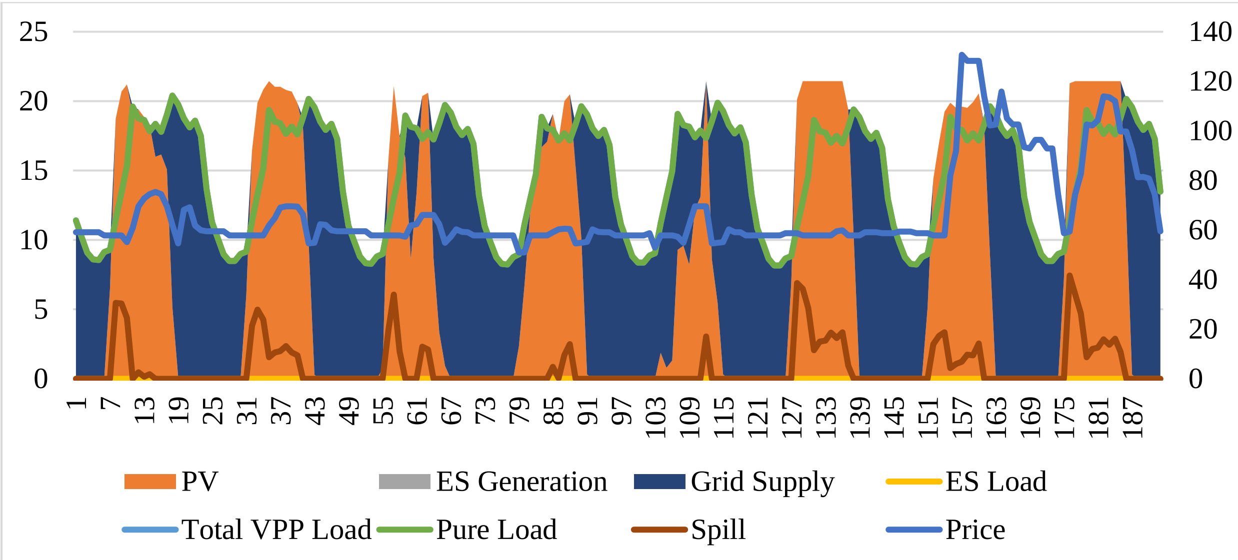


Figure 5.7: SOA VPP Demand and Supply - 30 MW PV installed

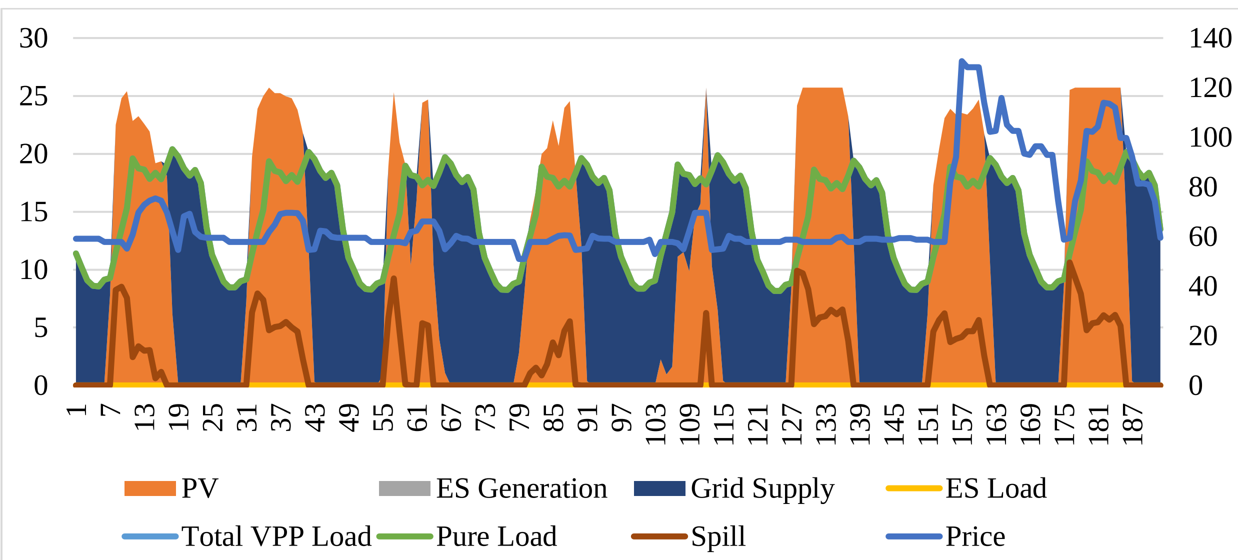


Figure 5.8: SOA VPP Demand and Supply - 36 MW PV installed

The results of the PV generation and the VPPs' financial parameters for one year are summarized in Table 5.14 to Table 5.17.

Table 5.14: EOA VPP results - Partial subsidy

EOA VPP - Partially Subsidized Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)	0	26,782.50	33,468.00	40,168.15
VPP Load (MWh)	112,661.95	112,661.95	112,661.95	112,661.95
Spill Energy (MWh)	0	927.2	4,058.84	8,741.80
VPP Net Position ($)	(4,437,464)	(3,568,102)	(3,390,950)	(3,238,498)
Cost of Energy ($/MWh)	39.39	32.67	30.1	28.75

Table 5.15: COA VPP results - Partial subsidy

COA VPP - Partially Subsidized Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		28,223.15	35,259.75	42,322.10
VPP Load (MWh)	94,843.70	94,843.70	94,843.70	94,843.70
Spill Energy (MWh)		1,955.76	5,896.28	10,818.48
VPP Net Position ($)	(4,241,503)	(3,281,993)	(3,092,228)	(2,919,410)
Cost of Energy ($/MWh)	44.72	34.60	32.60	30.78

Table 5.16: WOA VPP results - Partial subsidy

WOA VPP - Partially Subsidized Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		60,229.20	75,297.48	90,365.76
VPP Load (MWh)	104,870.79	104,870.79	104,870.79	104,870.79
Spill Energy (MWh)		6,249.92	14,613.80	24,032.94
VPP Net Position ($)	(5,906,234)	(4,221,538)	(3,989,317)	(3,792,380)
Cost of Energy ($/MWh)	56.32	40.25	38.04	36.16

Table 5.17: SOA VPP results - Partial subsidy

SOA VPP - Partially Subsidized Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		60,903.68	76,236.20	91,455.88
VPP Load (MWh)	112,080.80	112,080.80	112,080.80	112,080.80
Spill Energy (MWh)		6,578.91	16,187.67	26,821.86
VPP Net Position ($)	(8,241,621)	(5,486,003)	(4,993,551)	(4,525,008)

Cost of Energy ($/MWh)	73.53	48.95	44.55	40.37

The economic benefits recognized by the VPPs in a one-year period as a result of installing the PV units with reference to the business-as-usual case, where there is no PV, are quantified in Table 5.18 to Table 5.21.

Table 5.18: EOA VPP benefit - partial subsidy

EOA VPP Benefit Analyses - Partially Subsidized Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	17%	24%	27%
VPP Saving ($)	869,362	1,046,514	1,198,966
Payback period (Years)	30	31	32
Normalized benefit ($/MWh generated)	32.46	31.27	29.85

Table 5.19: COA VPP benefit - Partial subsidy

COA VPP Benefit Analyses - Partially Subsidized Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	23%	27%	31%
VPP Saving ($)	959,510	1,149,275	1,322,093
Payback period (Years)	27	28	29
Normalized benefit ($/MWh generated)	34.00	32.59	31.24

Table 5.20: WOA VPP benefit - Partial subsidy

WOA VPP Benefit Analyses - Partially Subsidized Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	29%	32%	36%
VPP Saving ($)	1,684,696	1,916,916	2,113,854
Payback period (Years)	15	17	18
Normalized benefit ($/MWh generated)	28.96	26.25	24.05

Table 5.21: SOA VPP benefit - Partial subsidy

SOA VPP Benefit Analyses - Partially Subsidized Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	33%	39%	45%
VPP Saving ($)	2,755,618	3,248,069	3,716,613
Payback period (Years)	9	10	10
Normalized benefit ($/MWh generated)	45.25	42.61	40.64

Although the normalized benefit is reducing while increasing the PV size, it still varies within an acceptable range of and we can consider an average normalized benefit of the VPPs for the purpose of comparison with the other areas as outlined in Table 5.22.

Table 5.22: Average normalized benefit - Partial subsidy

Average normalized benefit ($/MWh generated) Partially Subsidized Fuel Prices	
EOA VPP	31.2
COA VPP	32.61
WOA VPP	26.42
SOA VPP	42.83

5.2.3 International fuel prices

Table 5.23 shows the financial parameters of the different VPPs operating in an environment of international fuel prices with no PV units installed.

Table 5.23: Case 2 VPP results without PV

0 MW PV Installed – International Fuel Prices				
	EOA	**COA**	**WOA**	**SOA**
PV Generation (MWh)	0	0	0	0
VPP Load (MWh)	112,661.95	94,843.70	105,930.57	112,080.80
VPP DERs Net Position ($)	(8,206,009)	(7,981,583)	(12,896,702)	(19,419,155)
Cost of Energy ($/MWh)	72.84	84.16	121.746747	173.26

Under the international fuel prices, the system's prices are as shown in Table 5.8. As these system's prices are higher than those associated with the partially subsidized fuel prices, it is expected to have a higher contribution from the PV to disposition energy generated from expensive thermal generation units, unless the maximum capacity of the PV units were utilized under the partial fuel subsidy case. To illustrate the PV contribution to the demand, sample snapshots of the VPPs demand and supply for three scenarios of PV sizing (24 MW, 30 MW and 36 MW) are depicted in Figure 5.9 to Figure 5.17 in stacked charts.

- EOA

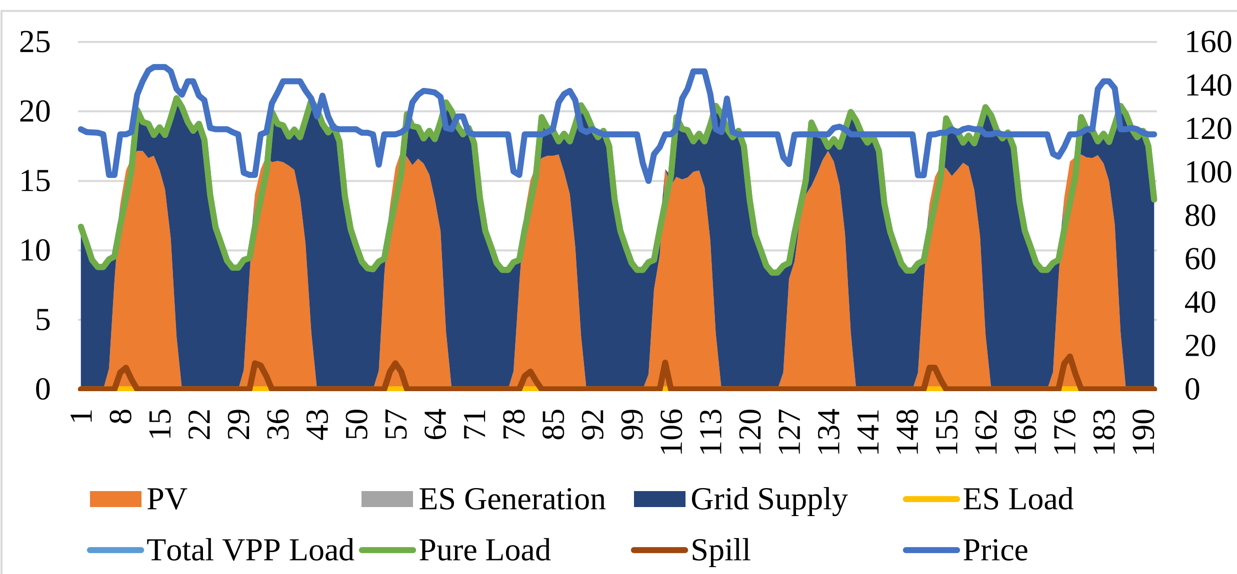


Figure 5.9: EOA VPP Demand and Supply - 24 MW PV installed

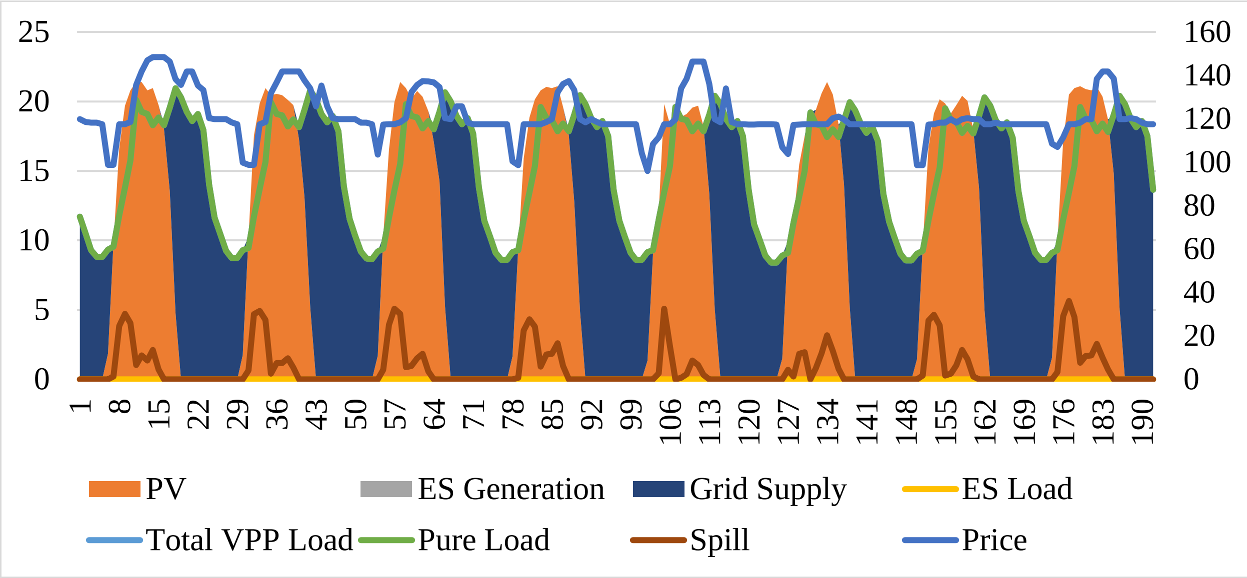


Figure 5.10: EOA VPP Demand and Supply - 30 MW PV installed

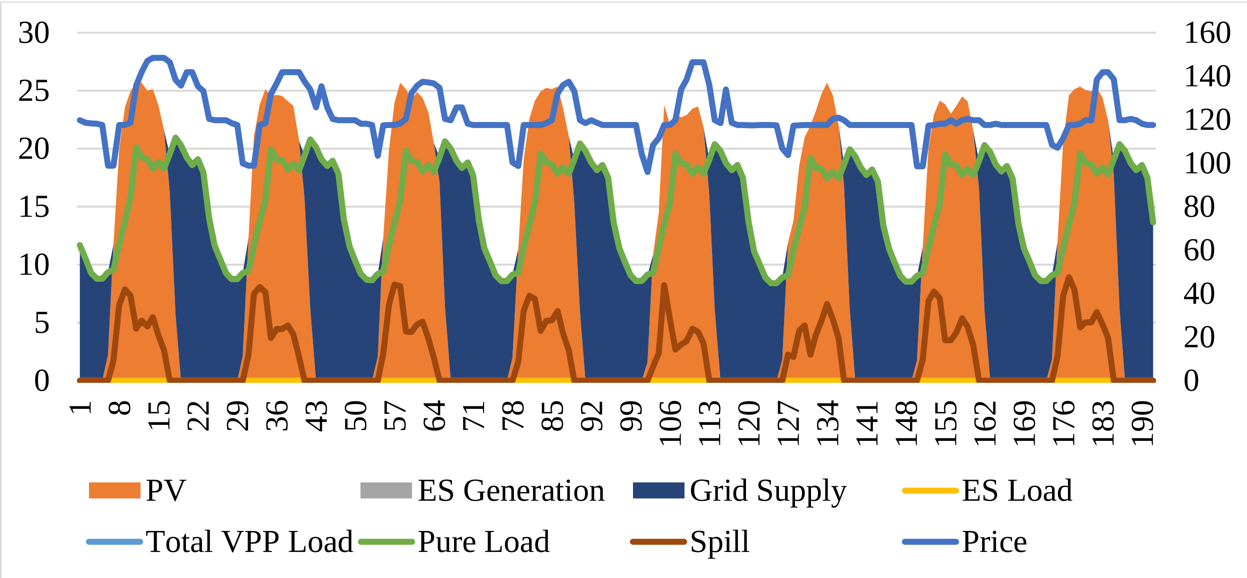


Figure 5.30: EOA VPP Demand and Supply - 36 MW PV installed

- COA

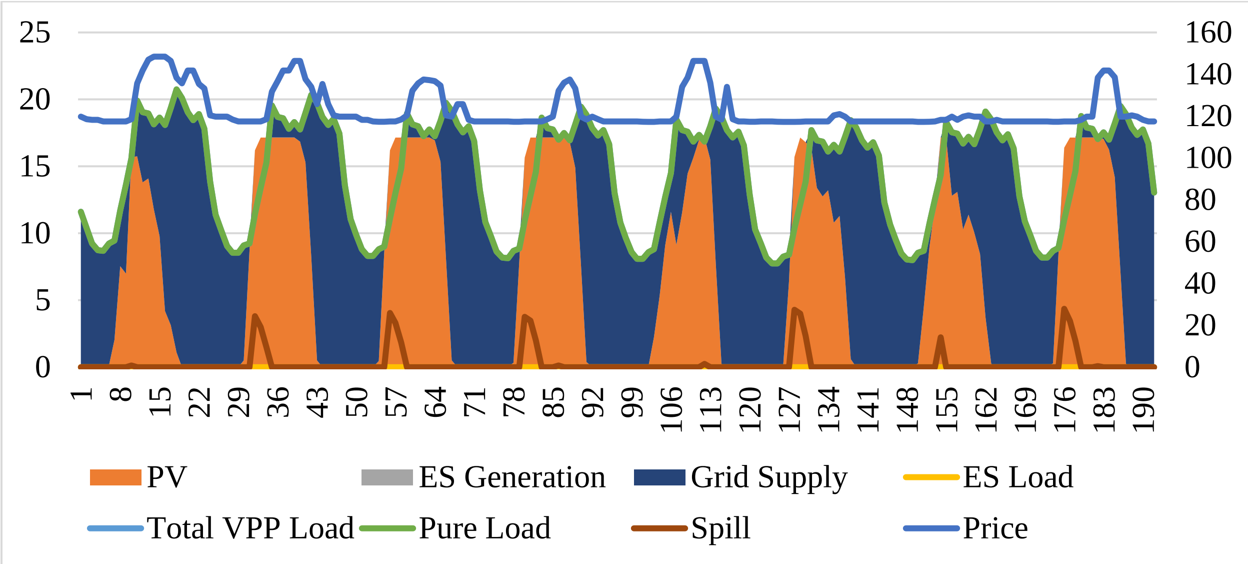


Figure 5.31: COA VPP Demand and Supply - 24 MW PV installed

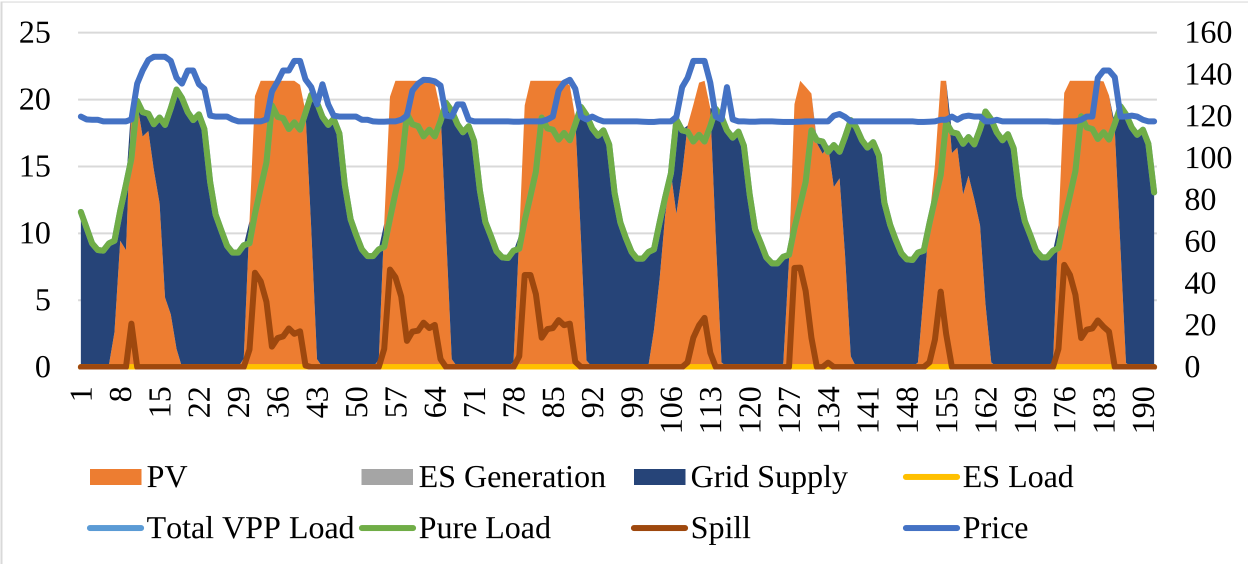


Figure 5.32: COA VPP Demand and Supply - 30 MW PV installed

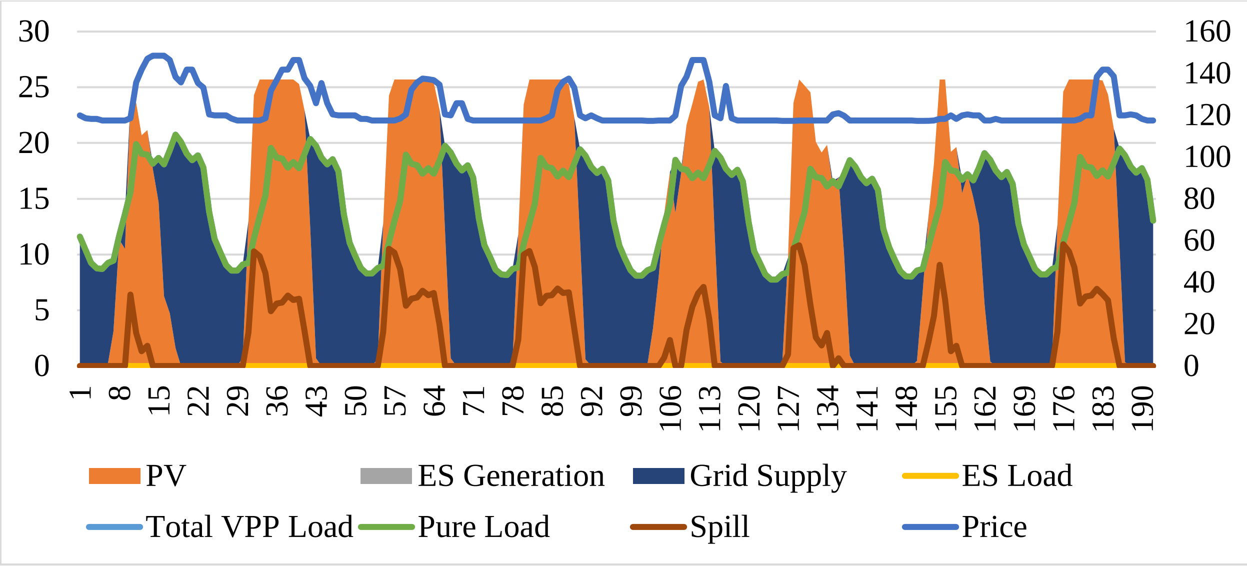


Figure 5.11: COA VPP Demand and Supply - 36 MW PV installed

- WOA

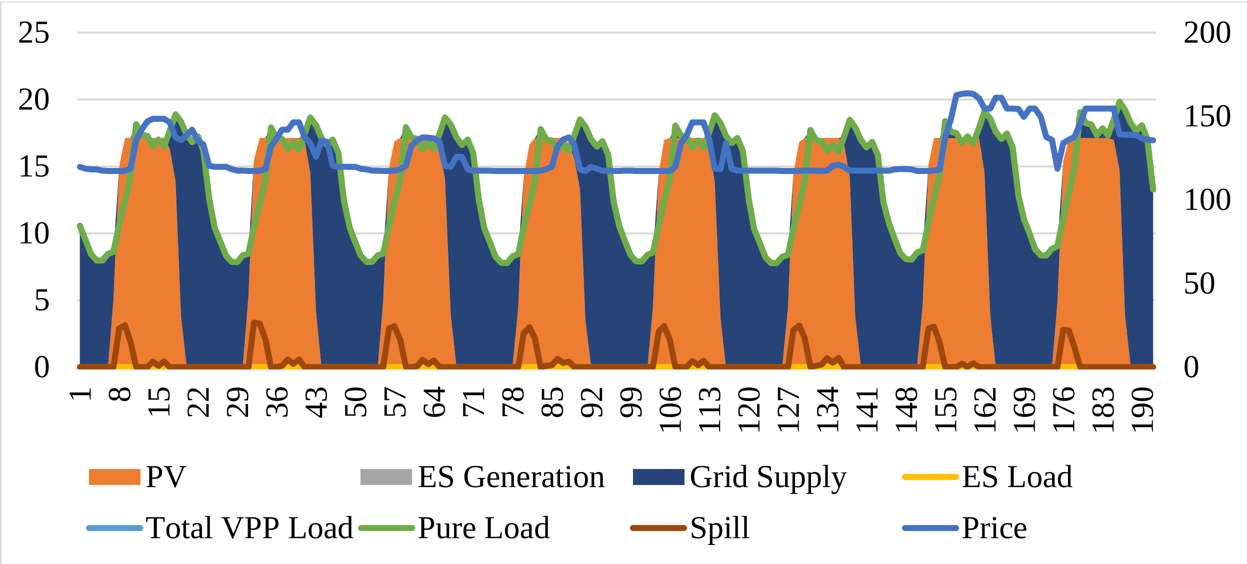


Figure 5.12: WOA VPP Demand and Supply - 24 MW PV installed

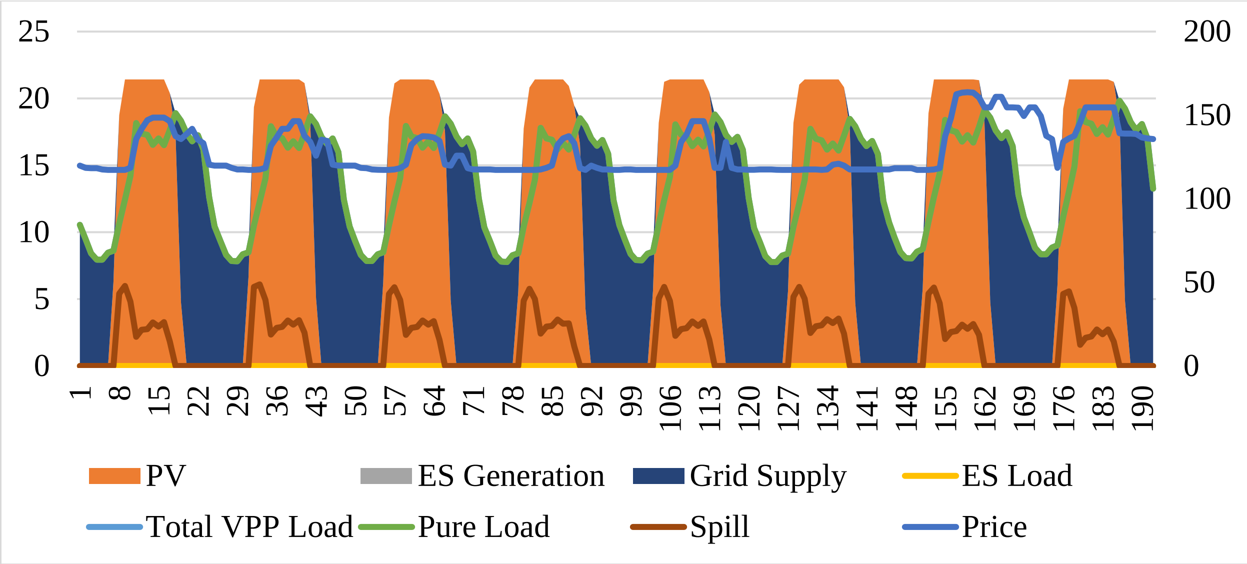


Figure 5.13: WOA VPP Demand and Supply - 30 MW PV installed

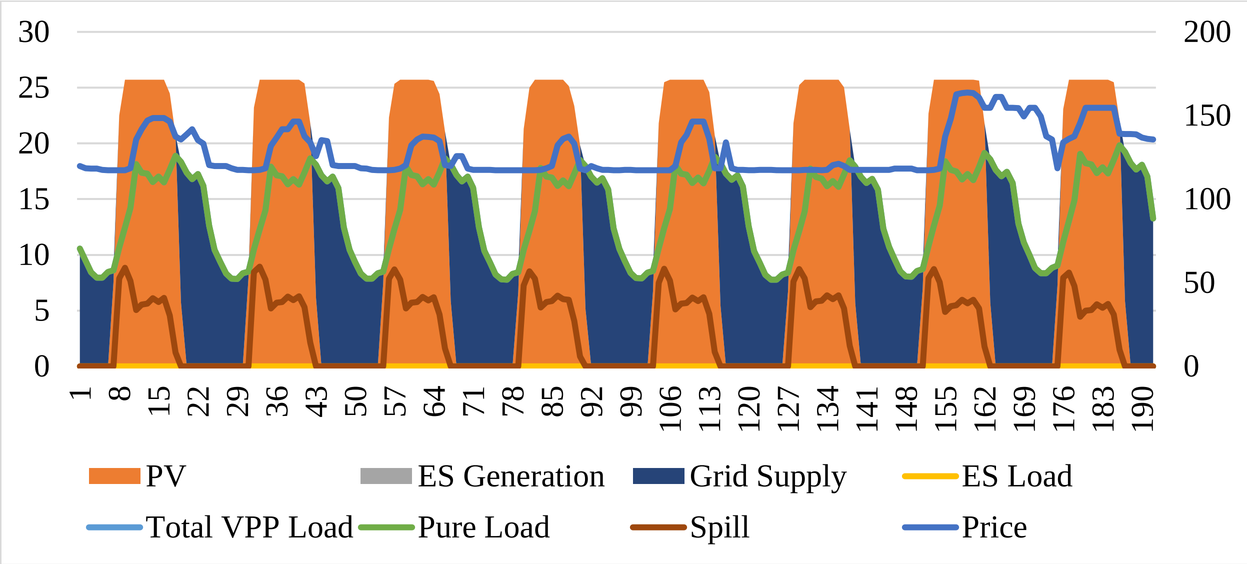


Figure 5.14: WOA VPP Demand and Supply - 36 MW PV installed

- SOA

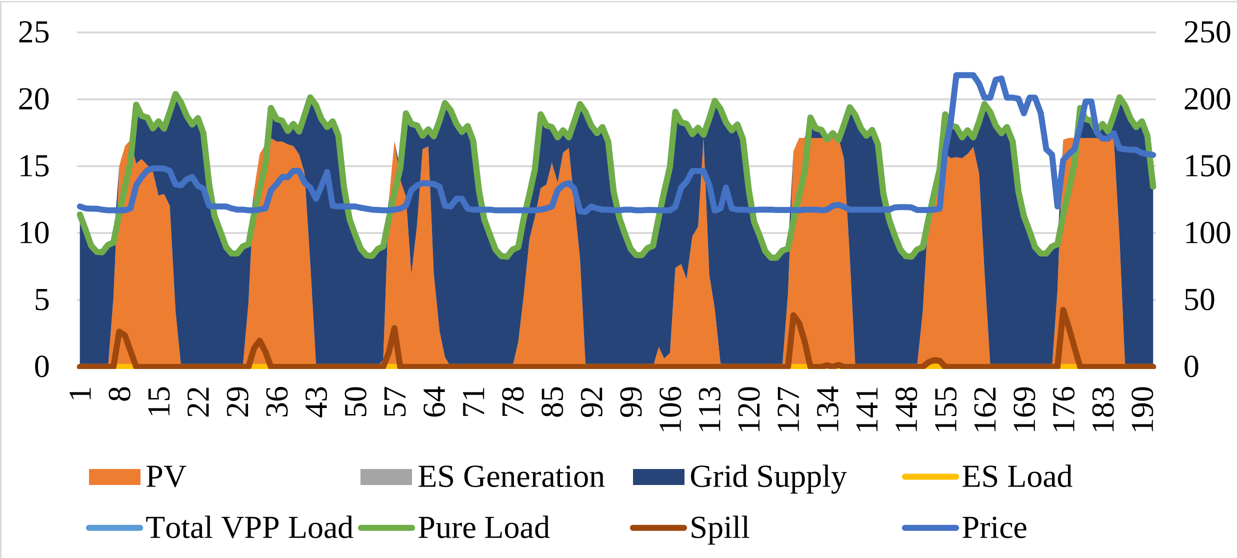


Figure 5.15: SOA VPP Demand and Supply - 24 MW PV installed

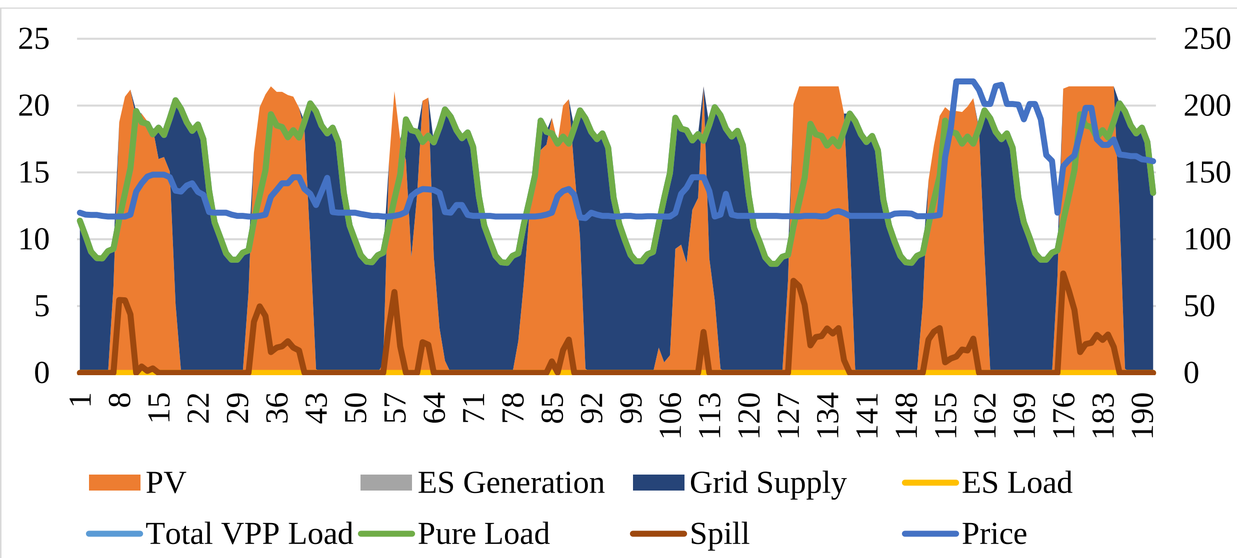


Figure 5.16: SOA VPP Demand and Supply - 30 MW PV installed

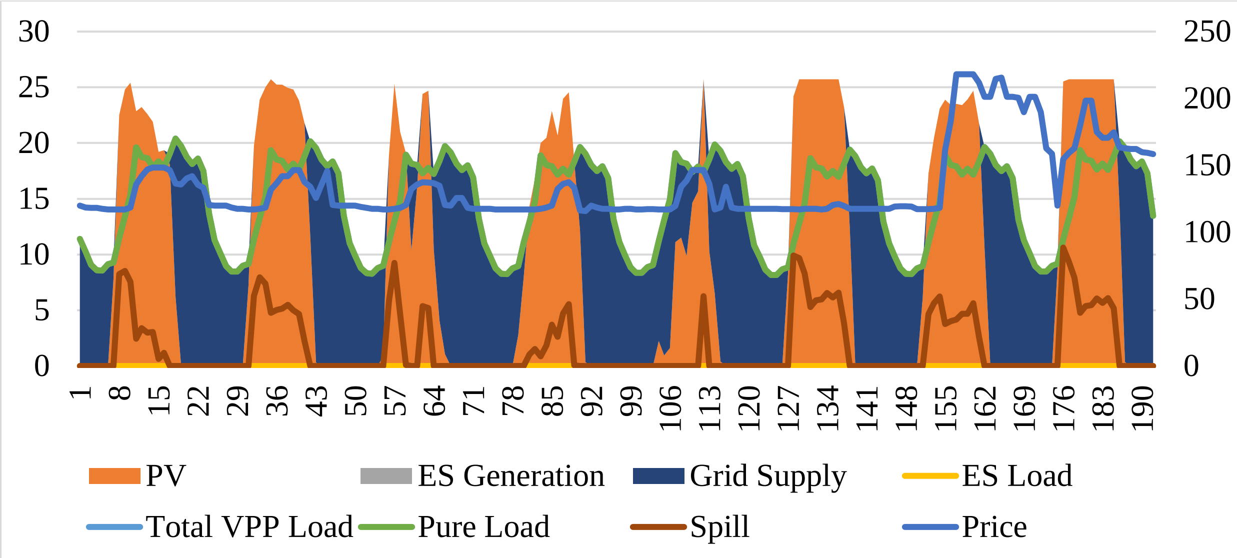


Figure 5.17: SOA VPP Demand and Supply - 30 MW PV installed

The PV generated energy along with its impact on the VPPs' financial parameters considering the three PV sizing are entailed in Table 5.24 to Table 5.27.

Table 5.24: EOA VPP results - International fuel prices

EOA VPP – International Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		44,752.50	55,925.45	67,120.25
VPP Load (MWh)	112,661.95	112,661.95	112,661.95	112,661.95
Spill Energy (MWh)		2,549.12	8,485.84	16,331.60
VPP Net Position ($)	(8,206,009)	(5,762,609)	(5,248,272)	(4,786,207)
Cost of energy ($/MWh)	72.84	51.15	46.58	42.48

Table 5.25: COA VPP results - International fuel prices

COA VPP - International Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		52,871.60	66,057.90	79,287.50
VPP Load (MWh)	94,843.70	94,843.70	94,843.70	94,843.70
Spill Energy (MWh)		8,866.96	17,451.88	27,106.52
VPP Net Position ($)	(7,981,583)	(5,313,365)	(4,767,323)	(4,256,194)
Cost of energy ($/MWh)	84.16	56.02	50.27	44.88

Table 5.26: WOA VPP results - International fuel prices

WOA VPP - International Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		60,229.20	75,297.48	90,365.76
VPP Load (MWh)	104,870.79	104,870.79	104,870.79	104,870.79
Spill Energy (MWh)		6,249.92	14,613.80	24,032.94
VPP Net Position ($)	(12,896,702)	(7,338,501)	(6,392,279)	(5,518,029)
Cost of energy ($/MWh)	122.98	69.98	60.95	52.62

Table 5.27: SOA VPP results - International fuel prices

SOA VPP – International Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		60,903.68	76,236.20	91,455.88
VPP Load (MWh)	112,080.80	112,080.80	112,080.80	112,080.80
Spill Energy (MWh)		6,578.91	16,187.67	26,821.86
VPP Net Position ($)	(19,419,155)	(10,791,219)	(9,100,977)	(7,461,605)
Cost of energy ($/MWh)	173.26	96.28	81.20	66.57

The results enclosed in the above Tables show noticeable improvements in the VPPs net financial position and the cost of energy as we install more PV capacities. These improvements are further illuminated in Table 5.28 to Table 5.31. The below benefits are in reference to the business-as-usual.

Table 5.28: EOA VPP benefit - International fuel prices

EOA VPP Benefit Analyses - International Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	30%	36%	42%
Saving ($)	2,443,400	2,957,737	3,419,802
Payback period (Year)	11	11	11
Normalized benefit ($/MWh generated)	54.60	52.89	50.95

Table 5.29: COA VPP benefit - International fuel prices

COA VPP Benefit Analyses - International Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	33%	40%	47%
Saving ($)	2,668,218	3,214,260	3,725,388
Payback period (Year)	10	10	10
Normalized benefit ($/MWh generated)	50.47	48.66	46.99

Table 5.30: WOA VPP benefit - International fuel prices

WOA VPP Benefit Analyses - International Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	43%	50%	57%
Saving ($)	5,558,202	6,504,423	7,378,673
Payback period (Year)	5	5	5
Normalized benefit ($/MWh generated)	92.28	86.38	81.65

Table 5.31: SOA VPP benefit - International fuel Prices

SOA VPP Benefit Analyses - International Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	44%	53%	62%
Saving ($)	8,627,936	10,318,177	11,957,549
Payback period (Year)	3	3	3
Normalized benefit ($/MWh generated)	141.67	135.34	130.75

For the sake of comparison, we consider an average of the normalized benefit for each VPP, as provided in Table 5.32.

Table 5.32: Average normalized benefits - International fuel prices

	Average normalized benefit ($/MWh generated) International Fuel Prices
EOA VPP	52.81
COA VPP	48.7
WOA VPP	86.77
SOA VPP	135.92

5.2.4 Indust

5.2.5 rial Load

In the previous sections, we were investigating the feasibility of integrating renewable energy resources (PV) through VPPs that aggregates residential demands sited in different areas of KSA. In an effort to further expand the study, we will explore the feasibility of integrating renewable energy resources through VPPs of industrial demands, where we will consider a demand profile of high load factor (0.93). In accordance with the methodology adopted for the residential loads, the unit commitment was simulated pursuing maximizing the profit of the VPPs with 3 PV sizing scenarios (24 MW, 30 MW and 36 MW) and international fuel prices. To offer an insight of the VPPs' industrial demand and supply balance with the participation of the PV units, the below Figure 5. to Figure 5.18 provide sample snapshots for the VPPs of the different areas assuming the PV size of 30 MW.

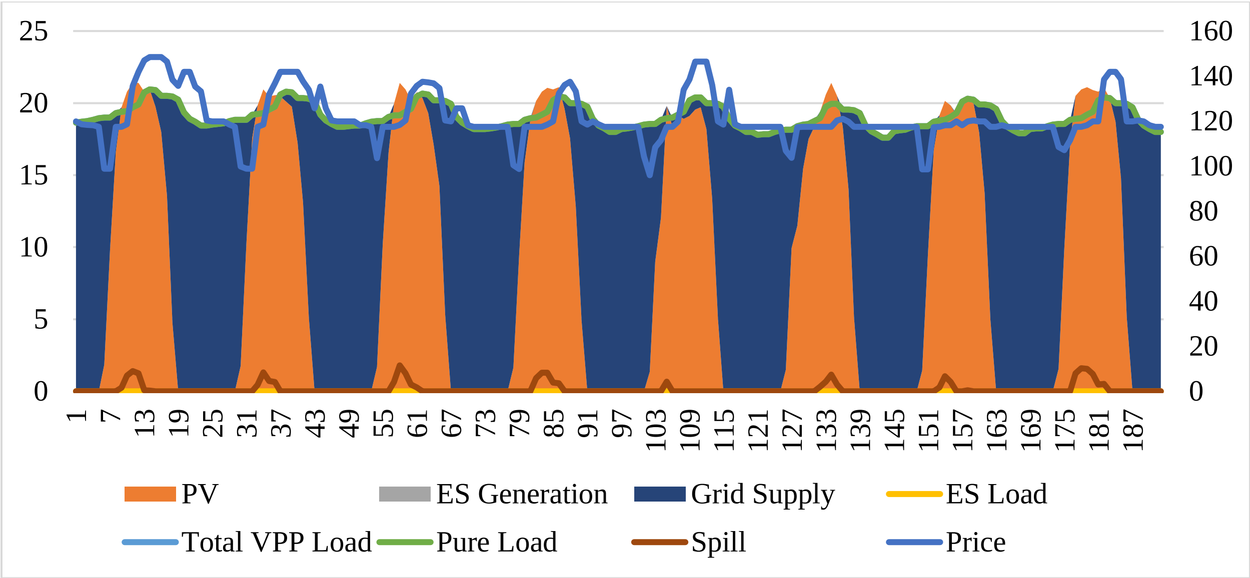


Figure 5.40: EOA VPP Demand and Supply - 30 MW PV installed - Industrial Demand

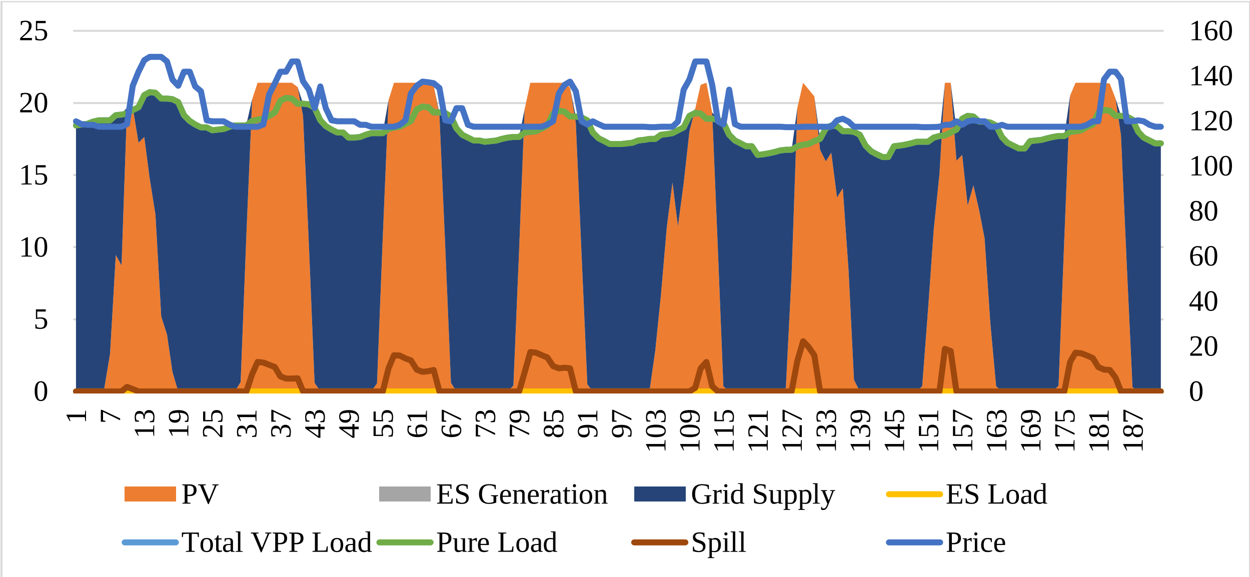


Figure 5.41: COA VPP Demand and Supply - 30 MW PV installed - Industrial Demand

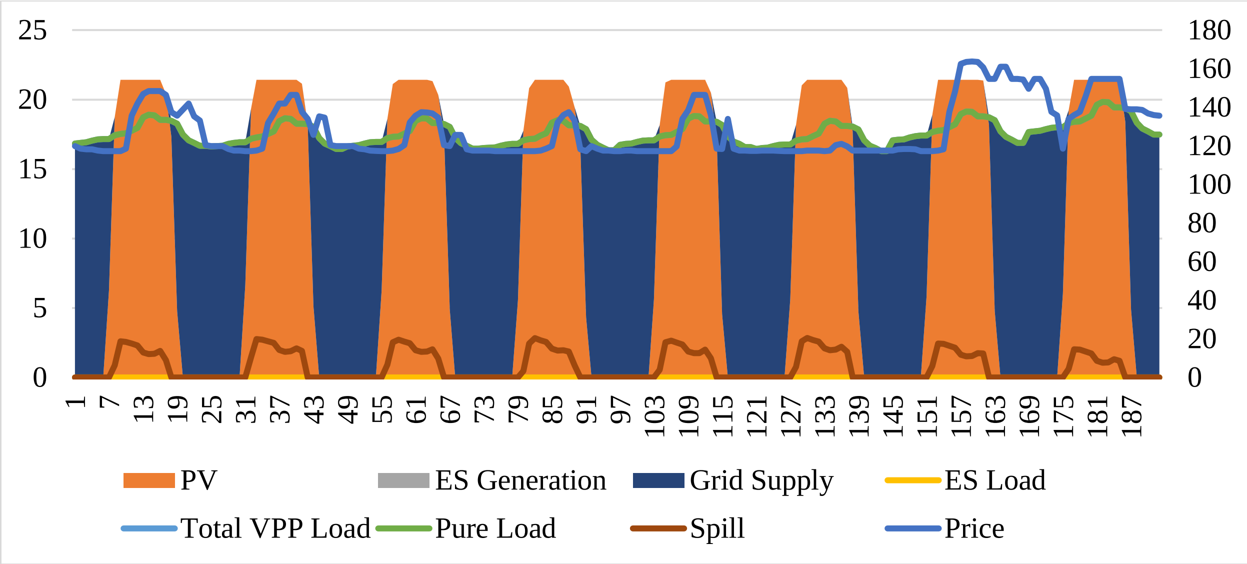


Figure 5.42: WOA VPP Demand and Supply - 30 MW PV installed - Industrial Demand

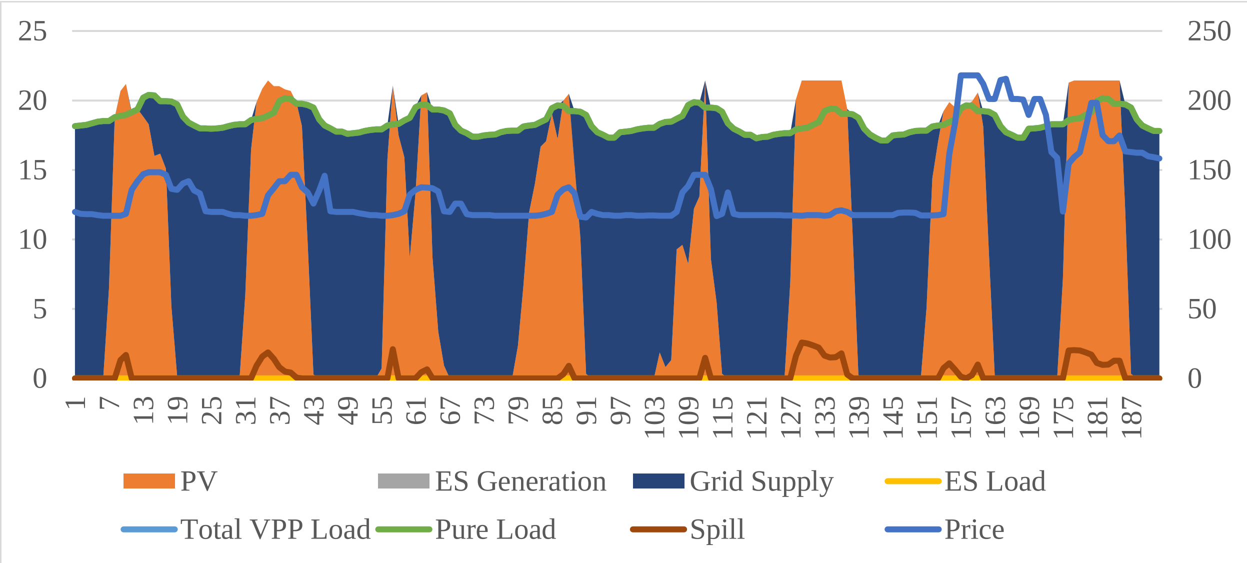


Figure 5.18: SOA VPP Demand and Supply - 30 MW PV installed - Industrial Demand

The industrial VPPs' financial results with the different sizes of the PV system installed are set out in Table 5.33 to Table 5.36.

Table 5.33: EOA industrial VPP results - International fuel prices

EOA Industrial VPP – International Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		44,752.50	55,925.45	67,120.25
VPP Load (MWh)	141,332.15	141,332.15	141,332.15	141,332.15
Spill Energy (MWh)		442.04	4,131.48	11,093.28
VPP Net Position ($)	(10,090,668)	(7,616,760)	(7,049,250)	(6,566,520)
Cost of energy ($/MWh)	71.40	53.89	49.88	46.46

Table 5.34: COA industrial VPP results - International fuel prices

COA Industrial VPP – International Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		52,871.60	66,057.90	79,287.50
VPP Load (MWh)	118,981.95	118,981.95	118,981.95	118,981.95
Spill Energy (MWh)		5,731.80	12,898.12	22,058.88
VPP Net Position ($)	(9,847,135)	(7,128,162)	(6,541,225)	(6,018,184)
Cost of energy ($/MWh)	82.76	59.91	54.98	50.58

Table 5.35: WOA industrial VPP results - International fuel prices

WOA Industrial VPP – International Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		60,229.20	75,297.48	90,365.76
VPP Load (MWh)	131,561.34	131,561.34	131,561.34	131,561.34
Spill Energy (MWh)		3,406.82	10,283.54	19,452.80
VPP Net Position ($)	(15,896,12)	(10,306,086)	(9,261,046)	(8,371,947)
Cost of energy ($/MWh)	120.83	78.34	70.39	63.64

Table 5.36: SOA industrial VPP results - International fuel prices

SOA Industrial VPP – International Fuel Prices				
	0 MW PV	**24 MW PV**	**30 MW PV**	**36 MW PV**
PV Generation (MWh)		60,903.68	76,236.20	91,455.88
VPP Load (MWh)	140,604.84	140,604.84	140,604.84	140,604.84
Spill Energy (MWh)		2,766.03	10,765.62	21,000.78
VPP Net Position ($)	(24,278,667)	(15,430,597)	(13,657,614)	(11,996,853)
Cost of energy ($/MWh)	172.67	109.74	97.13	85.32

It is clear from the results entailed in the above the Tables that VPPs with industrial VPPs reap financial benefit by installing solar PV systems, as reflected in their net financial position and the cost of serving each MWh of demand. As the size of the PV system installed increases, these two financial parameters improve further. Table 5.37 to Table 5.40 elaborate more on this improvement with reference to the case of no PV installed:

Table 5.37: EOA industrial VPP benefit - International fuel prices

EOA Industrial VPP Benefit Analyses – International Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	25%	30%	35%
Saving ($)	2,473,908	3,041,418	3,524,148
Payback period (Year)	11	11	11
Normalized benefit ($/MWh generated)	55.28	54.38	52.50

Table 5.38: COA industrial VPP benefit - International fuel prices

COA Industrial VPP Benefit Analyses – International Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	28%	34%	39%
Saving ($)	2,718,973	3,305,910	3,828,951
Payback period (Year)	10	10	10
Normalized benefit ($/MWh generated)	51.43	50.05	48.29

Table 5.39: WOA industrial VPP benefit - International fuel prices

WOA Industrial VPP Benefit Analyses – International Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction (%)	35%	42%	47%
Saving ($)	5,590,035	6,635,074	7,524,174
Payback period (Year)	5	5	5
Normalized benefit ($/MWh generated)	92.81	88.12	83.26

Table 5.40: SOA industrial VPP benefit - International fuel prices

SOA Industrial VPP Benefit Analyses – International Fuel Prices			
	24 MW PV	**30 MW PV**	**36 MW PV**
Required investment ($ million)	26	32	38
Cost of energy reduction	36%	44%	51%
Saving ($)	8,848,070	10,621,053	12,281,814
Payback period ($)	3	3	3
Normalized benefit ($/MWh generated)	145.28	139.32	134.29

The average normalized benefit of the industrial VPPs as per Table 5.41:

Table 5.41: Industrial VPP normalized benefit - International fuel prices

Average normalized benefit ($/MWh generated) International Fuel Prices	
EOA Industrial VPP	54.06
COA Industrial VPP	49.92
WOA Industrial VPP	88.06
SOA Industrial VPP	139.63

5.2.6 VPPs with Energy Storage

Due to the intermittent nature of the renewable energy resources, energy storage (ES) systems are usually coupled to the systems of renewable energy resources coming after rectifying the system imbalance brought by the renewables. In this part of the study, we augment the VPPs discussed in the previous sections with ES systems to examine their impact on the financial position of the residential VPPs, as it is expected the ES systems will improve the flexibility of the VPPs operation in a smart manner by charging at low systems prices and discharging while prices are high. For this purpose, the ES systems were added to the VPPs of the different areas where there are 30-MW

PV systems installed in each VPP. The ES systems were sized based on the excess PV generation from the demand of each VPP, as illustrated by Figure 5.19.

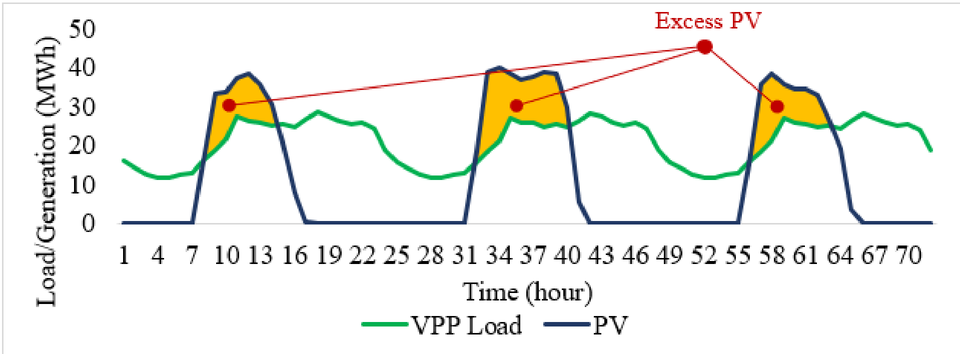


Figure 5.19: ES System Sizing

In the above Figure, the shaded areas, which represent the VPPs' PV excess generation are added for the full year and then averaged to the ES system's number of cycles per year. Assuming a total life cycle of 7,000 cycles for ES system and a lifetime of 20 years [25], the ES storage systems have 350 cycles per year. Accordingly, the ES size is mathematically expressed in Equation (5.2) and (5.3) as:

$$Battery\ Size = \frac{Excess\ PV}{350} \tag{5.2}$$

Where:

$$Excess\ PV = \sum_{k=1}^{8,760} (PV - Load)\ ; whenever\ PV > Load \tag{5.3}$$

Where: 8,760 is the number of hours per year

As per this formulation, the sizes of the ES systems of the VPPs used in the study are tabulated in Table 5.42.

Table 5.42: ES system sizes

VPP	EOA VPP	COA VPP	WOA VPP	SOA VPP
ES size (MWh)	30	60	60	60

In the same fashion we adopted in the exploring the economic feasibility of the investment in PV systems, for the ES systems, we used the Levelized Cost of Storage (LCOS) as the input variable O&M charge for the ES. With reference to [24] and [26], the LCOS of lithium ion batteries is calculated as 49 $/MWh, which is inclusive of investment, operational and financing cost. With this LCOS being considered in the simulation, the observation was that there is no contribution from the ES systems to serve the demand. This indicates that the current cost of energy storage does not make the investment in this technology feasible for energy bill management purposes via energy arbitrage. However, throughout the ES technology roadmap, it is expected that as we reach the year 2030, the cost of energy storage will drop dramatically to be as low as 35% of the current cost, which brings the LCOS to 17 $/MWh.

So, the simulations of the VPPs unit commitment were performed based on the envisioned low price of energy storage. The PV and ES generation of the VPPs along with their financial results are provided in Table 5.43 to Table 5.46.

Table 5.43: EOA VPP results with/without ES

EOA VPP – 30 MW PV – International Fuel Prices		
	No ES	**30 MWh ES**
PV Generation (MWh)	55,925.45	55,925.45
ES Generation (MWh)	-	980.50
VPP Load (MWh)	112,661.95	112,661.97

Spill Energy (MWh)	8,485.84	10,106.16
VPP Net Financial Position ($)	(5,248,272)	(5,128,587)
Cost of energy ($/MWh)	46.58	45.52
VPP Normalized benefit ($/MWh generated)	52.89	54.08

Table 5.44: COA VPP results with/without ES

COA VPP – 30 MW PV – International Fuel Prices		
	No ES	**60 MWh ES**
PV Generation (MWh)	66,057.90	66,057.90
ES Generation (MWh)	-	1,232.82
VPP Load (MWh)	94,843.70	94,843.26
Spill Energy (MWh)	17,451.88	22,118.45
VPP Net Financial Position ($)	(4,767,322)	(4,471,201)
Cost of energy ($/MWh)	50.27	47.14
VPP Normalized benefit ($/MWh generated)	48.66	52.17

Table 5.45: WOA VPP result with/without ES

WOA VPP – 30 MW PV – International Fuel Prices		
	No ES	**60 MWh ES**
PV Generation (MWh)	75,297.48	75,297.48
ES Generation (MWh)	-	196.32
VPP Load (MWh)	104,870.79	104,870.79
Spill Energy (MWh)	14,613.80	22,054.06
VPP Net Financial Position ($)	(6,392,279)	(5,548,531)

Cost of energy ($/MWh)	60.95	52.91
VPP Normalized benefit ($/MWh generated)	86.38	97.33

Table 5.46: SOA VPP results with/without ES

SOA VPP – 30 MW PV – International Fuel Prices		
	No ES	**60 MWh ES**
PV Generation (MWh)	76,236.20	76,236.20
ES Generation (MWh)	-	5,590
VPP Load (MWh)	112,080.80	112,081.20
Spill Energy (MWh)	16,187.67	24,669.15
VPP Net Financial Position ($)	(9,100,977)	(7,948,117)
Cost of energy ($/MWh)	81.20	70.91
VPP Normalized benefit ($/MWh generated)	135.34	140.19

As observed in the financial results, if the energy storage evolves and the cost decline significantly to the level forecasted for 2030, the ES systems will have the potential to positively impact the VPPs in terms of their net financial position, cost of energy as well as the normalized benefit. The extent to which the residential VPPs' financial metrics are improved is not as significant as that of the PV systems. For instance, the reduction in the cost of energy caused by the PV systems ranges from 30% to 62%. On the other hand, the reduction resulted from the ES systems is only in the range of 6% to 13%. However, this insignificant contribution of ES to the financial position of the VPPs does not refute the fact that the ES systems are capable to bring their owners decent financial returns, which can be accomplished by the ancillary services that ES systems are capable of such as voltage support, reserve, and frequency response. These services are considered as the major source of income for the ES systems owners, while the income realized from energy arbitrage is only 4% [25].

5.2.7 Case 2 Discussion

Unlike the case of individual DERs where they do not have access to the grid and the PV generation is constrained to the VPPs' demand, in this case, it is possible for the VPPs to generate energy in excess of their demand, which is an opportunity to make additional revenue by spilling the excess-of-demand energy to the grid. In all scenarios of PV sizing, the highest level of PV generation for one year is observed to be in the VPPs located in WOA and SOA, where the PV profiles of energy yields provide more energy than that of both EOA and COA. Moreover, the system's prices in WOA and SOA are higher than EOA and COA, which makes the PV units more economic to be utilized to meet the VPP demand as well as the grid's demand.

The results of Case 2 suggest that as we install larger sizes of PV, the VPP recognizes additional benefits in terms of saving in the VPP's net financial position as well as the reduction in the cost of energy. With regards to the normalized benefit, the relationship between the PV size and this metric is conversely proportional as the larger size of PV results in a high value in the denominator of equation (14), which brings the normalized benefit to a lower level. This indicates that as we increase the size of the PV, the rising trend of saving recognized by the VPP moves at a slower rate than the rate of increase in the energy generated from the PV. The VPP saving is improved in the cases where the PV units have a higher contribution to the peak demand (higher capacity credit) and higher contribution when the system's prices are higher, so more expensive energy from thermal units is displaced.

With reference to the normalized benefits of the VPPs (Table 5.22 and Table 5.32), it is observed that the VPP located in SOA realizes the highest benefit for each MWh generated from the VPP's

PV units. The assessment of the industrial VPPs across the different areas also revealed the same conclusion as SOA industrial VPP had the highest normalized benefit. This feature of SOA VPP comes from the high system's price in the area resulted from burning high-value fuel than in the other regions.

5.3 Case 3 Simulation results

In Case 2, we have simulated the profit maximization for the individual VPPs and we have analyzed their behavior and financial results when they operate for the best of their own interest. Conversely, this case addresses the VPPs' operation for the interest of the whole system assuming they are centrally operated while having access to the grid with the objective of minimizing the system's cost. In the same manner by which we addressed Case 1 and Case 2, the operation strategy of the VPPs and their financial indicators are analyzed in this case considering the three fuel pricing scenarios as follows:

5.3.1 Domestic fuel prices

Similar to the previous case, under the domestic fuel prices, the system's prices do not allow for economic investment in PV units within the VPPs in all areas. Accordingly, investment in PV units at the premise of the domestic fuel prices makes no economic sense for the VPPs.

5.3.2 Partially subsidized fuel prices

When the VPP's exist in a market environment of prices linked to partially subsidized fuel prices, VPPs are expected to realize more contribution from the PV. Snapshots of the contribution of the PV units with a size of 30 MW to the VPPs' demand and the grid is exhibited in the demand and supply stacked charts shown in Figure 5.20 to Figure 5.23.

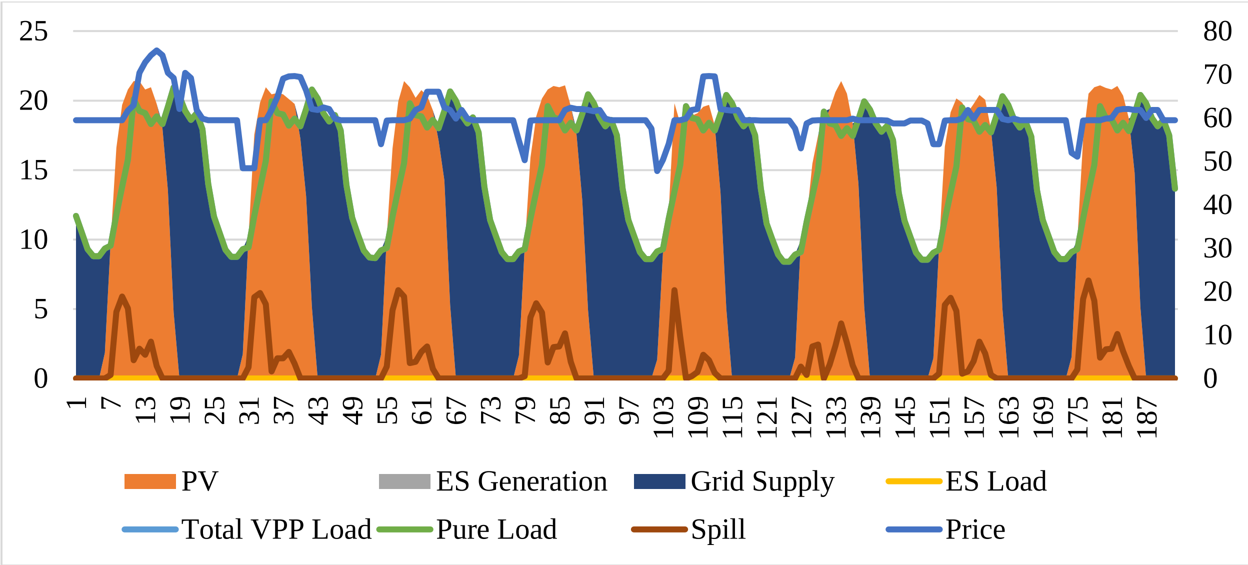


Figure 5.20: EOA VPP Demand and Supply - 30 MW PV installed

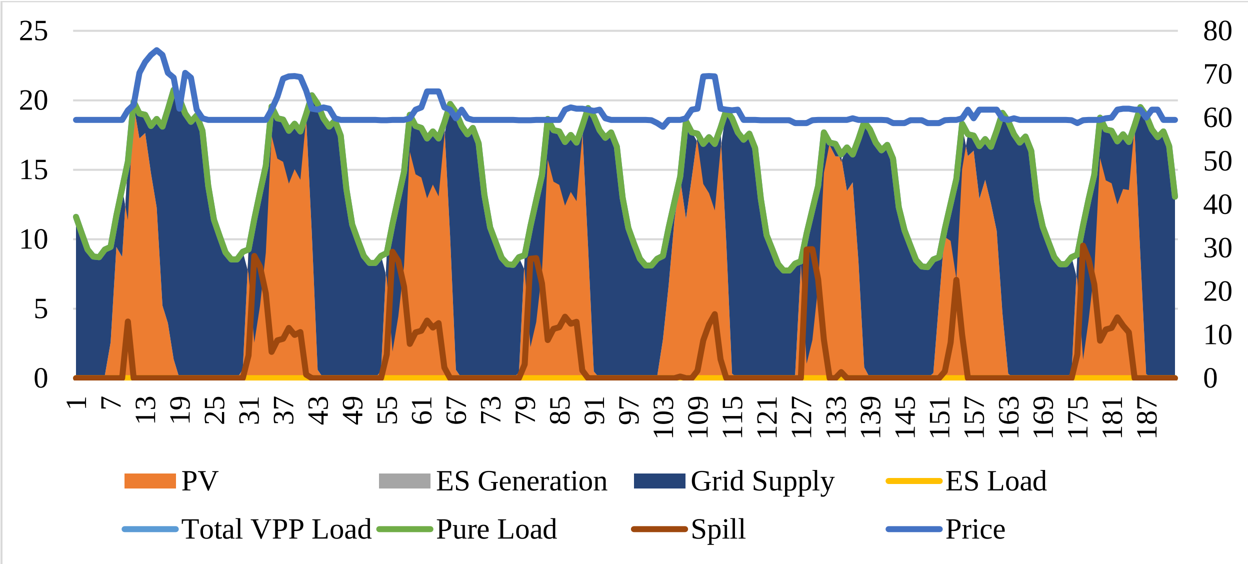


Figure 5.21: COA VPP Demand and Supply - 30 MW PV installed

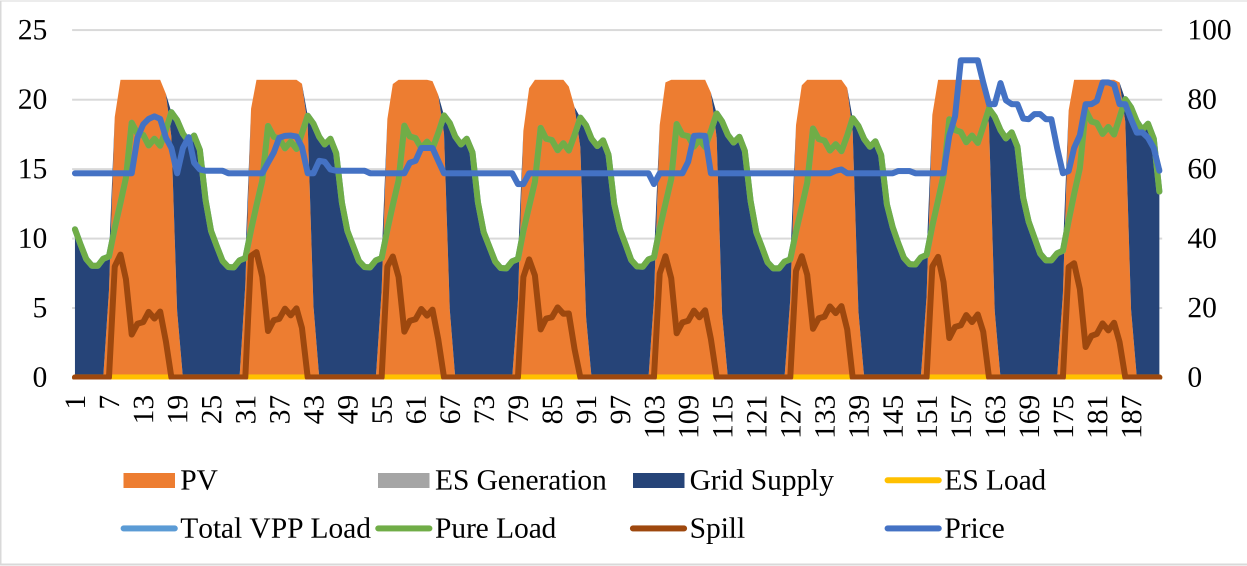


Figure 5.22: WOA VPP Demand and Supply - 30 MW PV installed

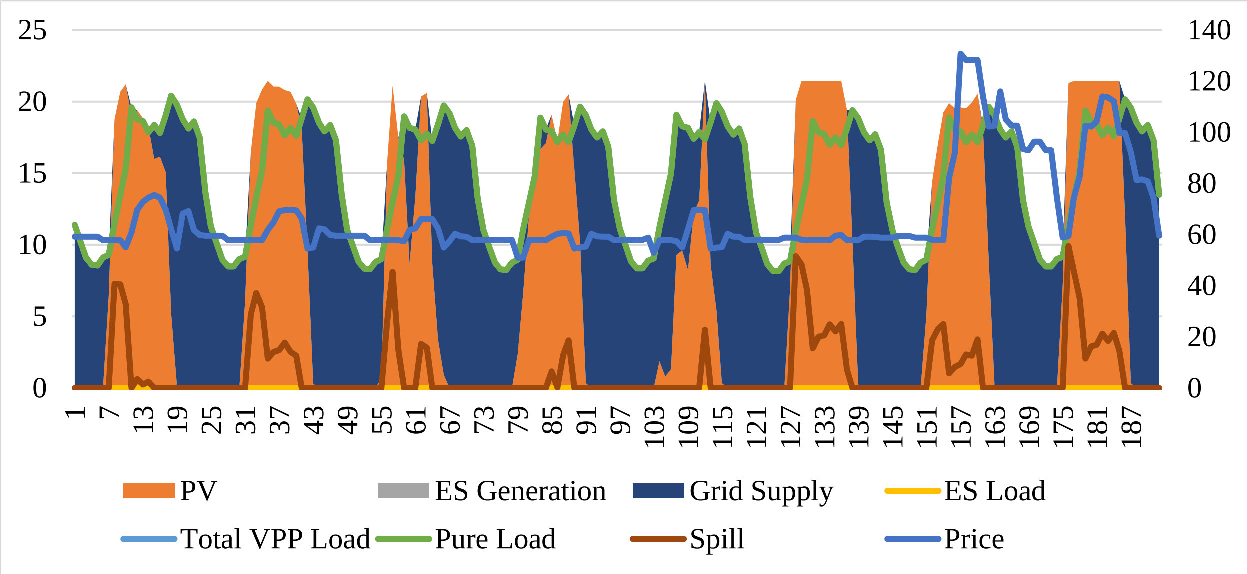


Figure 5.23: SOA VPP Demand and Supply - 30 MW PV installed

The amount of energy generated by the PV units along with their financial impact on the PV are presented in Table 5.47.

Table 5.47: Case 3 VPPs results - Partial subsidy

30 MW PV installed				
	EOA VPP	COA VPP	WOA VPP	SOA VPP
PV Generation (MWh)	33,495.62	27,711.58	75,297.48	76,236.20
VPP Load (MWh)	112,661.95	94,843.70	104,870.79	112,080.80
Spill Energy (MWh)	5,075.40	7,423.51	21,448.22	21,583.13
VPP Net Position ($)	(3,336,212)	(2,406,832)	(3,678,615)	(4,610,030)
Cost of energy ($/MWh)	29.61	25.38	34.73	41.13
Normalized Benefit ($/ MWh generated)	32.88	66.21	29.58	47.64
VPP Saving ($)	1,101,251	1,834,671	2,287,305	3,631,591
Payback Period (Year)	29	18	14	9

5.3.3 International fuel prices

As the fuel prices go to higher levels, the system's prices escalate proportionately. Accordingly, the PV units are expected to have higher economic feasibility and hence, have more influence on supplying the VPPs' demand and the grid demand. Figure 5.24 to Figure 5. offer samples of the demand and supply to and from the VPPs in case of 30-MW PV installed over a window of 8 days from the year.

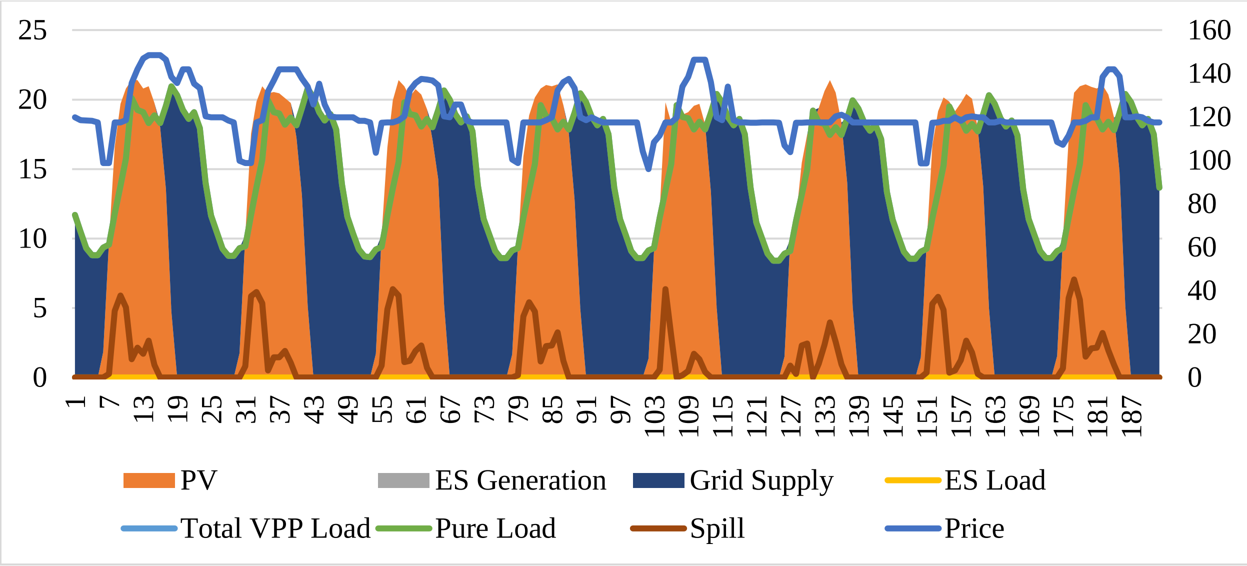


Figure 5.24: EOA VPP Demand and Supply - 30 MW PV installed

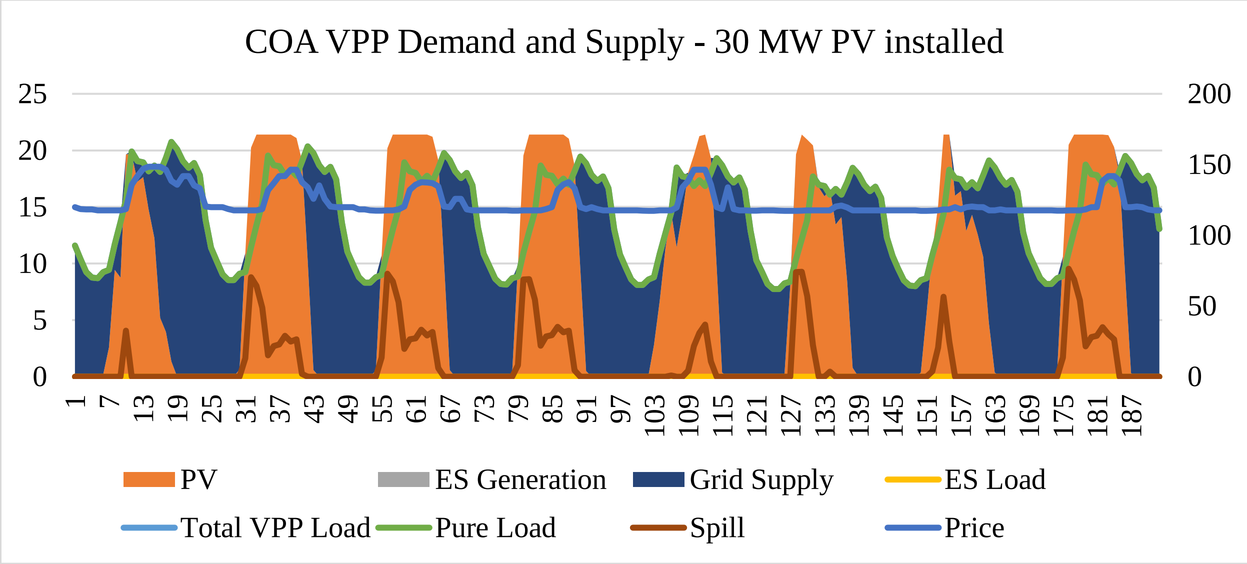


Figure 5.50: COA VPP Demand and Supply - 30 MW PV installed

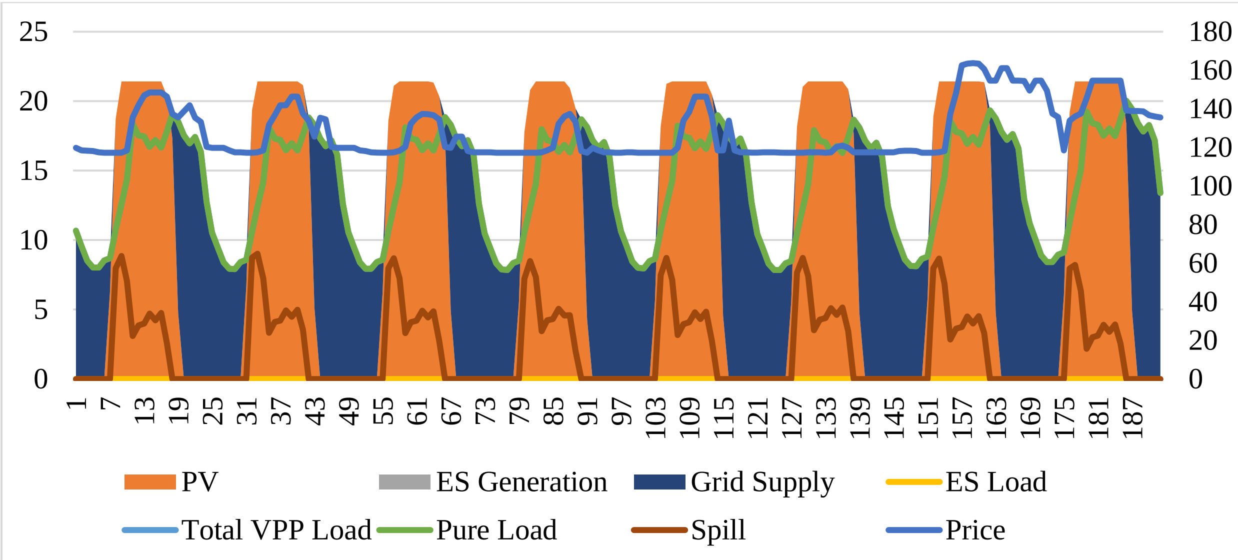


Figure 5.51: WOA VPP Demand and Supply - 30 MW PV installed

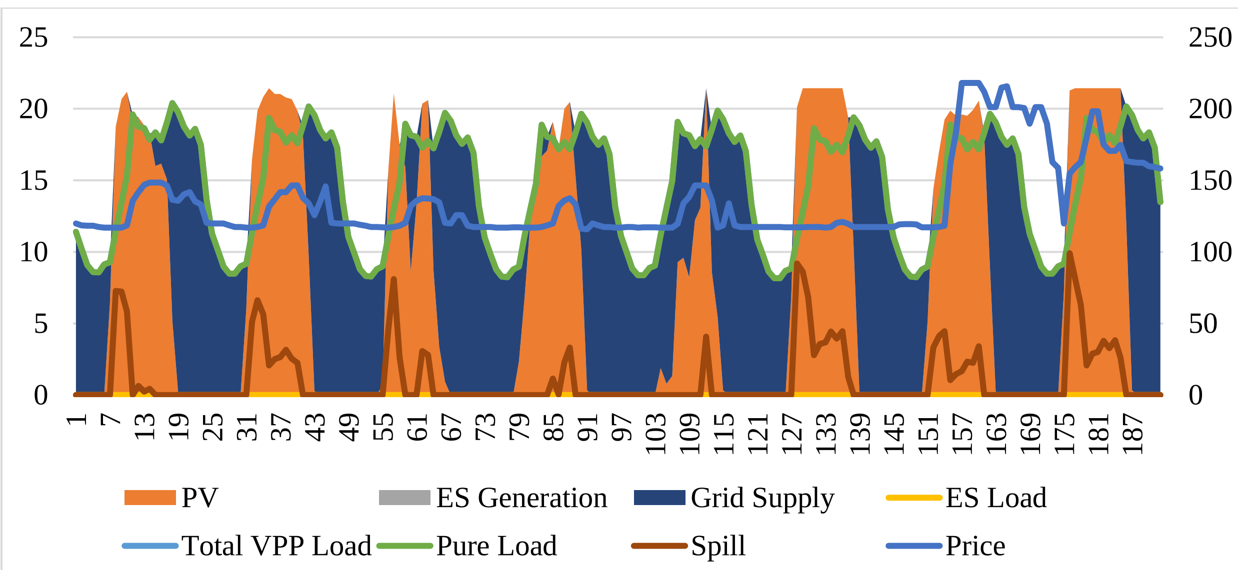


Figure 5.52: SOA VPP Demand and Supply - 30 MW PV installed

Table 5.48 sheds light on the yearly financial impact of the PV on the VPPs over the different areas.

Table 5.48: Case 3 VPPs results - International fuel prices

30 MW PV installed				
	EOA VPP	COA VPP	WOA VPP	SOA VPP
PV Generation (MWh)	55,925.45	66,057.9	75,297.48	76,236.20
VPP Load (MWh)	112,661.95	94,843.70	105,930.57	112,080.80
Spill Energy (MWh)	8,485.84	17,451.88	14,613.8	16,187.7
VPP Net Position ($)	(5,249,561)	(4,768,703)	(6,394,635)	(9,110,732)
Cost of energy ($/MWh)	46.6	50.3	60.98	81.3
Normalized Benefit ($/ MWh generated)	52.86	48.64	86.35	135.22
VPP Saving ($)	2,956,447	3,212,880	6,502,068	10,308,422
Payback Period (Year)	11	10	5	4

5.3.4 Current International fuel prices

The international fuel prices used in the previous sections are based on forecasts issued by EIA. However, those forecasts did not materialize, as the world has witnessed a steep drop in the fuel prices, which is primarily driven by the worldwide outbreak of the Corona Virus (COVID-19) that impacted the fuel demand in different sectors. In this section, we will explore the economic feasibility to integrate the PV systems through VPPs under these circumstances within the premise of the dropped fuel prices. The prices used to simulate this case, which are valid on March 26, 2020, are as per Table 5.49:

Table 5.49: Current International Fuel Prices [32]

	$/MMBTU	**$/BBL**
Gas	1.67	
AL	4.89	28
AH	4.40	25
HFO	4.2	26.5

For this purpose, we are considering the standard VPP of 30 MW PV installed in a central operation scenario. Figure 5.25 to Figure 5.27 provide snapshots of the VPPs' demand and supply balance followed by a summary of the VPPs' financial results showing the benefits as compared to the status quo of no PV installed in Table 5.50.

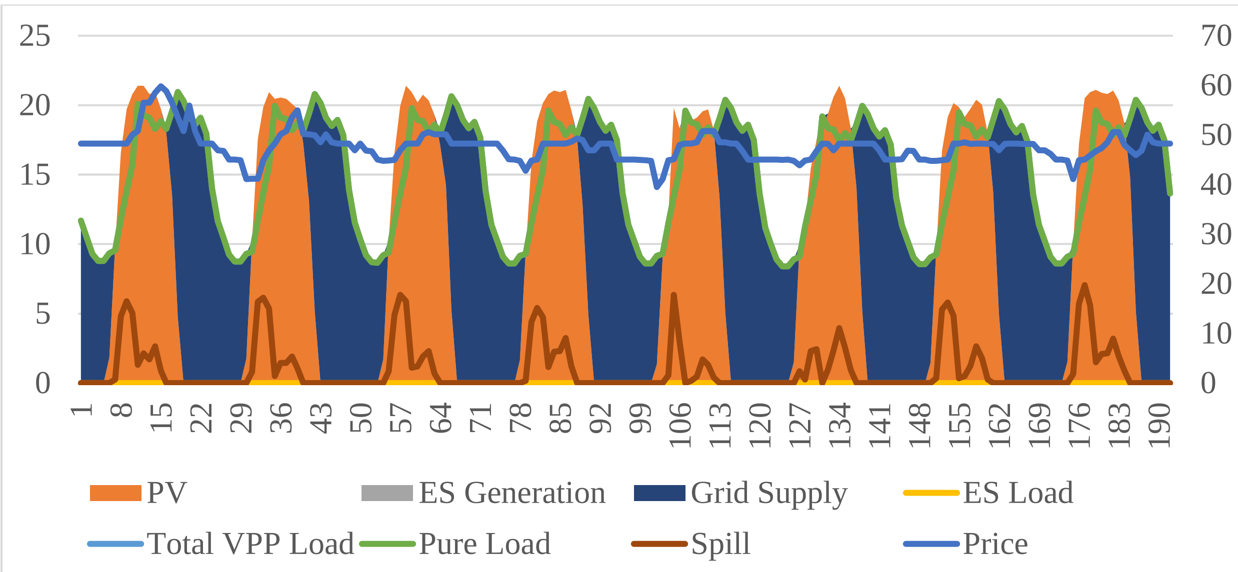


Figure 5.25: EOA VPP demand and supply - 30 PV installed - Dropped International fuel prices

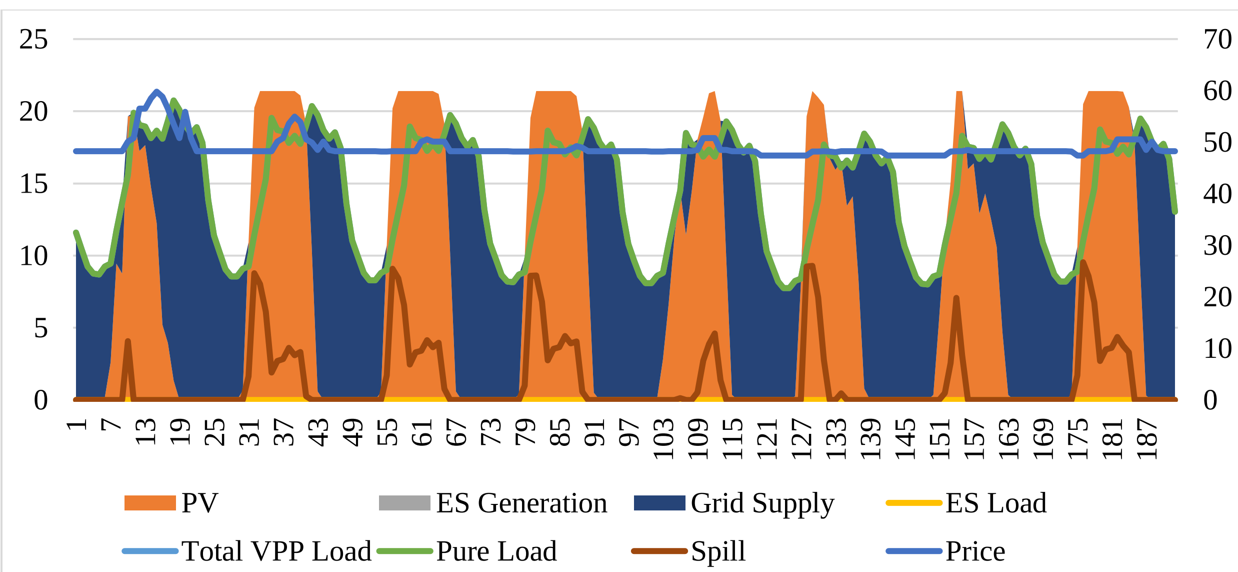


Figure 5.26: COA VPP demand and supply - 30 PV installed - Dropped International fuel prices

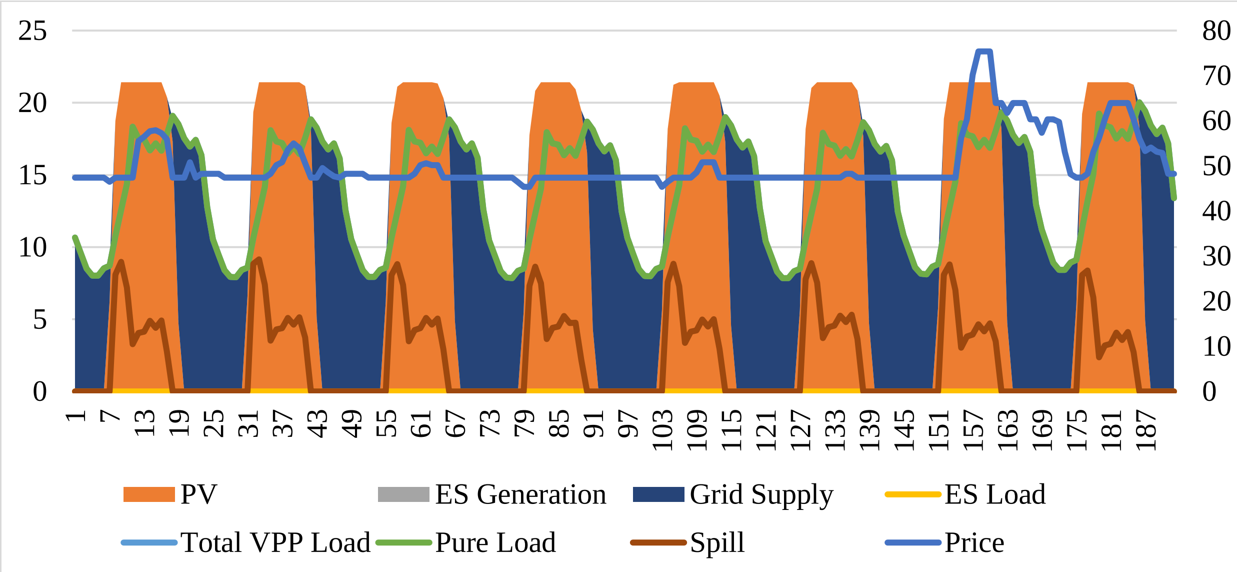


Figure 5.55: WOA VPP demand and supply - 30 PV installed - Dropped International fuel prices

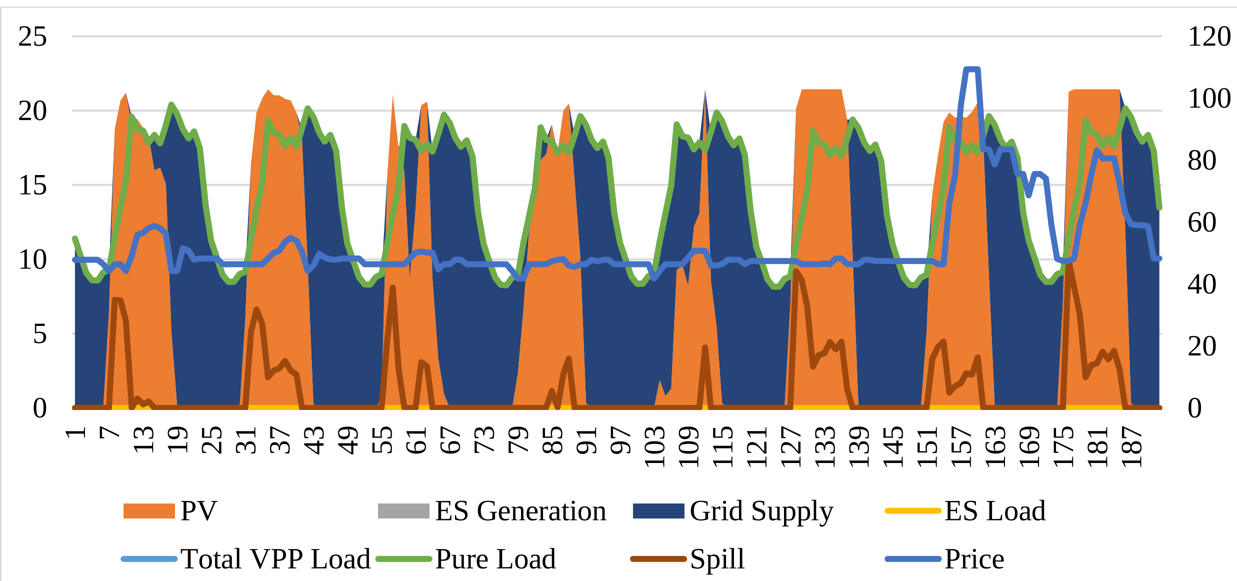


Figure 5.27: SOA VPP demand and supply - 30 PV installed - Dropped International fuel prices

Table 5.50: Case 3 VPPs results - Current international fuel prices

30 MW PV Installed				
	EOA VPP	COA VPP	WOA VPP	SOA VPP
PV Generation (MWh)	33,606.30	36,018.05	75,297.48	76,236.20
VPP Load (MWh)	112,661.95	94,843.70	105,930.57	112,080.80
Spill Energy (MWh)	5,106.90	7,663.57	21,920.70	21,583.13
VPP net financial position ($)	(2,916,258)	(2,668,145)	(3,292,388)	(4,071,806)
Cost of energy ($/MWh)	25.89	28.13	31.08	36.33
VPP Benefit ($/MWh generated)	21.55	23.55	21.41	34.99
VPP Saving ($)	724,085	848,388	1,612,183	2,667,856
Payback Period (Year)	44	38	20	12

5.3.5 Case 3 Discussion

It is observed that the feature of SOA residential VPP having the highest normalized benefit among the VPPs of the other areas continues to carry validity under the case of the central operation of the system. Also, it was observed that the currently dropped fuel prices are influential to the economic feasibility of the investment in the PV systems. With these prices in mind along with the PV systems' current cost, the investment in the PV systems is less feasable than the case of the forecasted international prices as well as the partially subsidized prices. This is manifested in the lower benefits recognized by the VPPs from installing PV systems as well as the longer payback periods when fuel prices are dropped.

5.4 Application of REPDO projects

As part of the Saudi National Renewable Energy Program (NREP), the Renewable Energy Projects Development Office (REPDO) of the Ministry of Energy (MoE) has announced two rounds of renewable energy projects inclusive of small scale PV projects [33],[34]. The sites of these projects are depicted in blue colors in Figure 5.28 and their capacities are as provided in Table 5.51.

Table 5.51: REPDO small-scale projects

Project/Site	Capacity (MW)
Rafha	20
Madinah	50
Layla	80
Wadi Dawasir	120

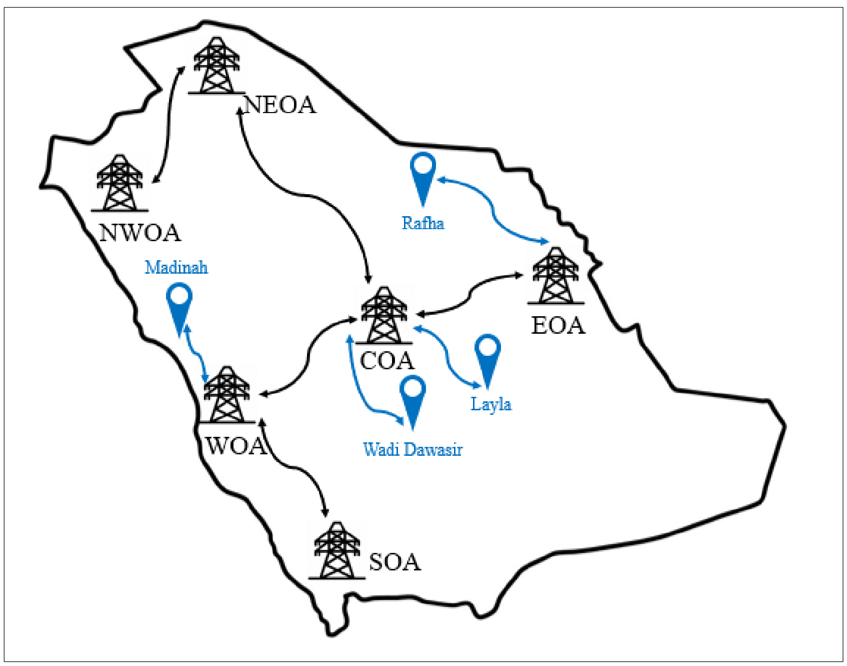


Figure 5.28: REPDO projects sites

In this section, we will examine the economic feasibility of integrating these projects to the grid through residential VPPs. The residential demand of the VPPs is designed to have a typical residential load profile so that the peak demand can be met with the peak output of the PV. With respect to the output profile of each of the PV projects, we have tapped into the features of the PVSyst software to generate the time series output of each project for one full year. The geographical information of the sites (i.e. the latitude, longitude and altitude) used as input to the software to create the output profile based on satellite information of the meteorological conditions of each site. The unit commitment simulations of these projects were carried out considering the international fuel prices. These VPPs will be operating in light of the system's prices of their respective areas, as illustrated in Figure 5.28. For this case in specific, the lowest LCOE bids received for Rafha project (34.87 $/MWh) and Madinah project (19.4 $/MWh) are used as the PV's VOM for these projects and their respective areas. Also, as the off-taker of the generation of these projects is anticipated to be the Principal Buyer, the central operation of the VPPs is being considered here. Figure 5.29 to Figure 5. provide insight of the demand and supply balance of VPPs coupled with REPDO's small scale PV projects, followed by the VPPs' financial result in Table 5.52 to Table 5.55.

5.4.1 REPDO Projects VPP Results

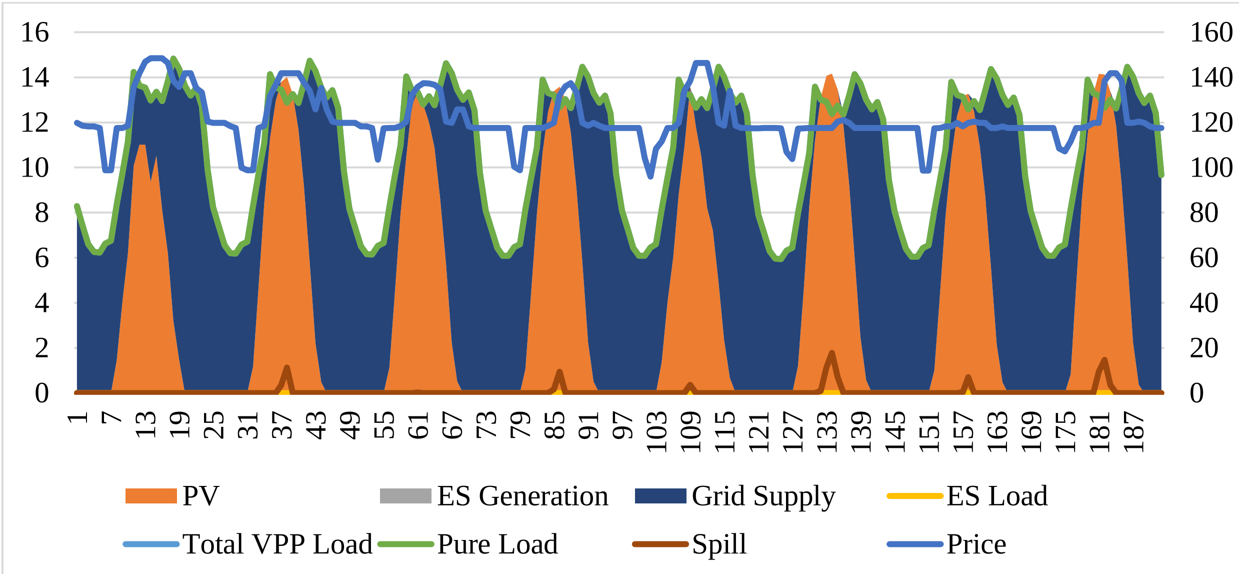


Figure 5.29: Rafha VPP - International fuel prices

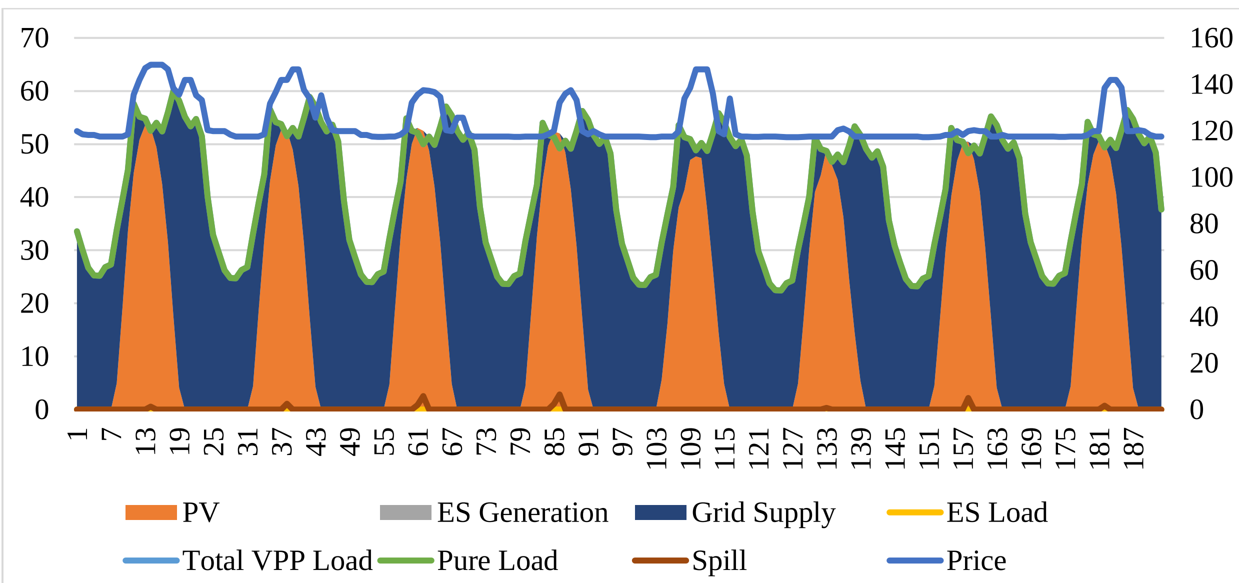


Figure 5.30: Layla VPP - International fuel prices

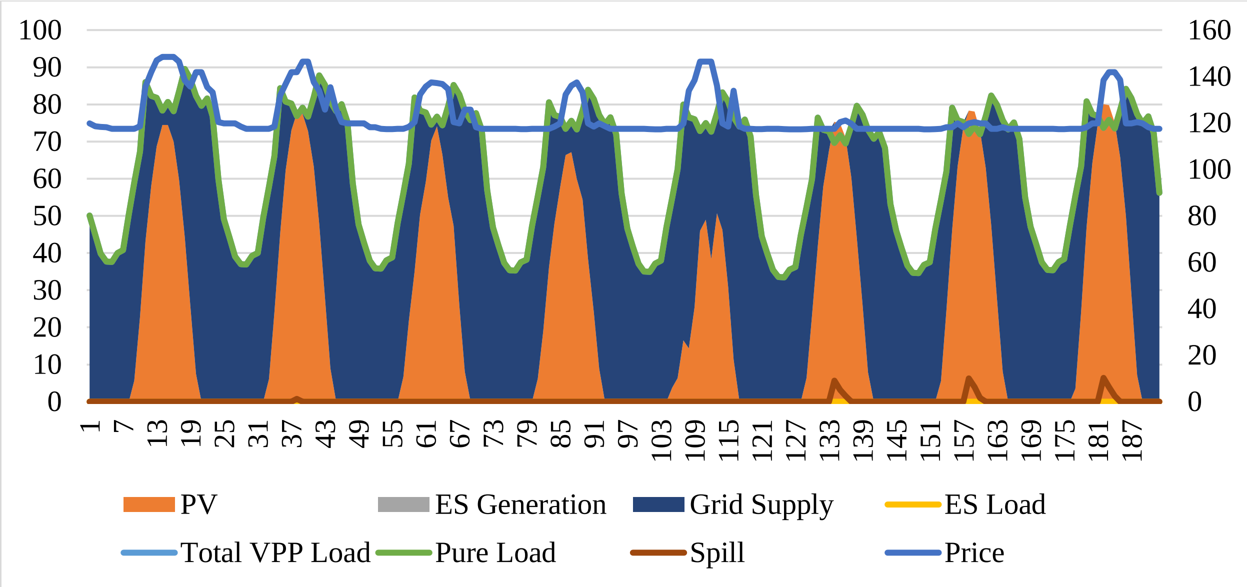


Figure 5.60: Wadi Dawasir VPP - International fuel prices

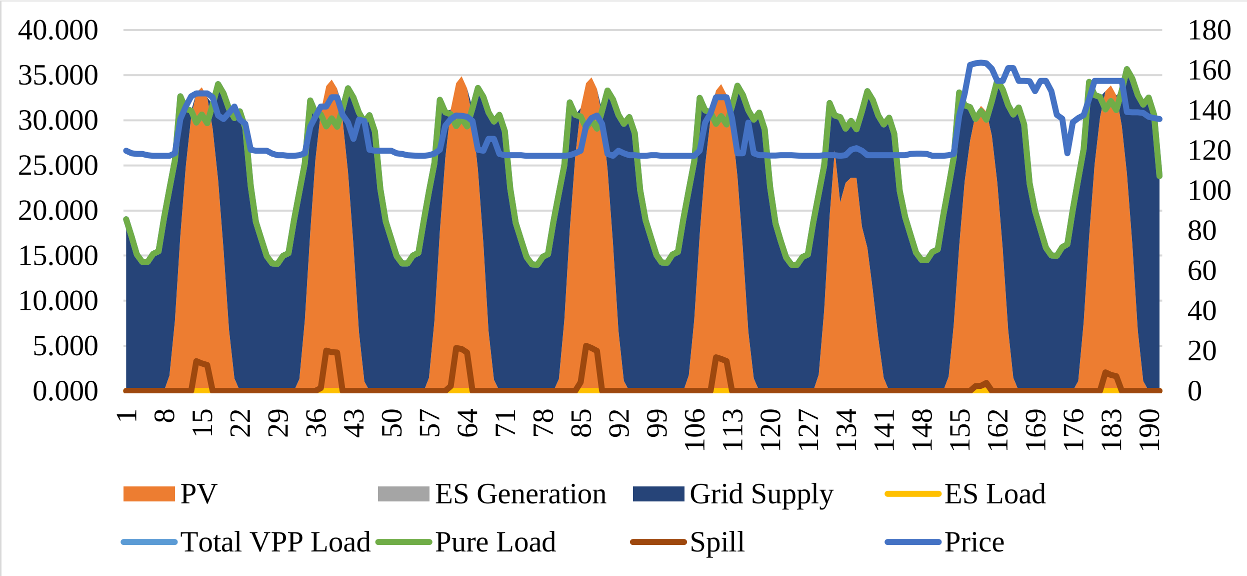


Figure 5.61: Madinah VPP - International fuel prices

Table 5.52: Rafha VPP results - International fuel prices

Rafha VPP – International fuel prices			
	Rafha VPP		EOA VPP
	0 MW PV	20 MW PV	30 MW PV
PV Generation (MWh)	-	18,532.12	33,998.39
VPP Load (MWh)	79,803.02	79,803.02	112,661.95
Spill Energy (MWh)	-	885.24	5,226.36
VPP Net Position ($)	(5,812,608)	(4,268,852)	(5,486,712)
Cost of energy ($/MWh)	72.84	53.5	48.7
VPP normalized benefit ($/MWh generated)		83.3	79.98
VPP Saving ($)		1,543,756	2,719,296
Payback Period (Year)		14	12

Table 5.53: Layla VPP results - International fuel prices

Layla VPP – International fuel prices			
	Layla VPP		COA VPP
	0 MW PV	80 MW PV	30 MW PV
PV Generation (MWh)	-	154,578.07	66,085.35
VPP Load (MWh)	274,492.59	274,492.59	94,843.70
Spill Energy (MWh)	-	38,837.56	21,820.72
VPP Net Position ($)	(23,099,250)	(15,753,777)	(4,522,136)
Cost of energy ($/MWh)	84.15	57.39	47.68
VPP normalized benefit ($/MWh generated)		47.52	52.35
VPP Saving ($)		7,345,473	3,459,447
Payback Period (Year)		12	10

Table 5.54: Table 5.57: Wadi Dawasir VPP - International fuel prices

Wadi Dawasir VPP – International fuel prices			
	Wadi Dawasir VPP		COA VPP
	0 MW PV	120 MW PV	30 MW PV
PV Generation (MWh)	-	235,648.57	66,085.35
VPP Load (MWh)	409,566.45	409,566.45	94,843.70
Spill Energy (MWh)	-	59,497.33	21,820.72
VPP Net Position ($)	(34,466,072)	(23,161,584)	(4,522,136)
Cost of energy ($/MWh)	84.15	56.55	47.68
VPP normalized benefit ($/MWh generated)		47.97	52.35
VPP Saving ($)		11,304,488	3,459,447
Payback Period (Year)		12	10

Table 5.55: Madinah VPP results - International fuel prices

Madinah VPP – International fuel prices			
	Madinah VPP		WOA VPP
	0 MW PV	50 MW PV	30 MW PV
PV Generation (MWh)	-	96,709.79	75,297.48
VPP Load (MWh)	188,606.07	188,606.07	105,930.57
Spill Energy (MWh)	-	17,355.55	21,448.22
VPP Net Position ($)	(22,961,9617)	(13,079,657)	(5,261,531)
Cost of energy ($/MWh)	121.75	69.35	49.67
VPP normalized benefit ($/MWh generated)		102.19	101.4
VPP Saving ($)		9,882,303	7,635,170
Payback Period (Year)		6	5

5.4.2 REPDO Projects Discussion:

As per the results entailed in the above results, it can be concluded that integrating REPDO small scale projects to the grid via VPPs of residential demand results in favorable financial impacts on those VPPs in terms of enhanced net financial positions, normalized VPP benefit as well as the reduced cost of energy.

According to these results, it is apparent that Madinah VPP realizes the highest benefit among the VPPs associated with the other REPDO projects. The cost of energy for Madinah VPP drops by 41%, which comes higher than that of the other projects' VPP, where the cost of energy drops by 30-33%. Moreover, the payback period for the Madinah VPP's investment in installing the PV units is the shortest as compared to the other VPPs. The payback period of Madinah VPP is 6 years, which is 50% lower than the payback period of the other projects. This is attributed to the prices of the systems associated with Madinah project, as it is part of the WOA, where high value fuel types are burned to generate power, which eventually has an impact on the system price. It is noteworthy that the VPPs of REPDO small scale projects have the same characteristics of their respective operational areas. This evident by the normalized benefits and payback periods of REPDOs projects that are close enough to those metrics associated with their respective operational areas VPPs.

Chapter 6: Conclusion and Future Work

It was observed from the study that the current domestic fuel prices in KSA do not incentivize the investment in building PV systems for the VPPs, as it is more economic for the VPPs to supply its demand from the grid at a lower cost than installing in-house PV. However, as the fuel prices get liberalized to reach the international fuel prices, the VPPs start to realize the economic value of installing PVs in managing their cost of energy. In this case, it becomes more economic for VPP to build PV systems to meet part of its demand than purchasing energy from the grid at a high price, which reflects the higher fuel prices. Accordingly, building PV systems for VPPs in the areas where low efficient power plants exist and higher value fuel types are burned results in higher economic benefits for the VPP than building the PVs in other areas of more efficient units and cheaper fuels. Consequently, given the existing system characteristics and fuel availability, the VPPs of SOA and WOA realize more economic benefits by installing PV systems than the VPPs of EOA and COA.

The same conclusion was proven applicable for REPDO projects VPPs, as Madinah VPP, which operates within WOA, sees more benefits than the other projects operating at the premise of EOA and COA. As far as the ESS are concerned, their installation was not cost-effective given their current high cost. Even when the the anticipated drop in the ESS down the roadmap was considered, we have observed that the economic benefit brought by the ESS in managing the VPPs' energy cost is insignificant. This alludes to the fact that ESS is not an appropriate candidate for cost of energy management.

In a nutshell, integrating the PV system in KSA on the distribution side through VPPs has a potential benefit to the end-users, as it will assist in managing their electricity bills. However, reaping such benefits was observed to be contingent to fuel prices reform. Also, the extent to which the VPPs recognize the economic benefits varies according to the geographical location of the VPP. The existing tariff system set by the regulator in KSA (ECRA) for the different sectors ranges from 43 $/MWh to 85 $/MWh, which fall within the energy prices envelop covered by fuel prices sensitivity addressed in this study. Accordingly, it can be concluded that under the current electricity tariff environment and the evolving PV LCOE, building PV systems in a VPP has the potential to improve the VPPs cost of energy.

It is worth mentioning that this research was an eye-opener to various aspects in the areas of VPPs, fuel pricing and subsidy, renewables energy resources and ESS. Accordingly, it is not possible to have a comprehensive view of these subjects through one thesis. Therefore, below are suggested topics for future works:

1. Consideration of other fuel availability scenarios in KSA such as availing gas to the west coast.
2. Explore the economic benefits of the ancillary services that can be provided by ESS in KSA.
3. Investigate the economic impact of applying Transmission Use of System (TUoS) charges to the VPPs. It could also reveal the ESS's capability to shave VPPs' peaks and manage the cost of energy.
4. Consider introducing subsidies for renewable energy projects.
5. Perform the study with a more detailed transmission system model, which could have an impact on the systems price.
6. Consider introducing subsidies for renewable energy projects.

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