A SYSTEM COST ANALYSIS OF EMBEDDED GENERATION VS UTILITY-SCALE SOLAR PV

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Abstract: South Africa's latest integrated resource plan describes a rapid solar photovoltaic (PV) build programme, with 7 gigawatts of new capacity being built by 2030. Virtually all of this capacity will be built in the form of utility-scale solar PV plants in areas of highest solar resource. This paper analyses the system-cost implications of an alternative arrangement where the solar PV is connected to the distribution network, known as small-scale embedded generation (SSEG). SSEG reduces overall system costs by reducing electricity losses and resulting fuel expenditure, and, in instances where peak demand is reduced, by reducing capital expenditure on network upgrades and peaking power plants. However, the upfront capital cost of utility-scale solar PV is lower (due to economies of scale) and usually has a higher capacity factor (due to optimum location and orientation, and the use of trackers) when compared to SSEG. This paper quantifies the tradeoffs associated with installing SSEG in various sectors in South Africa compared to installing the same amount of utility-scale PV. A comprehensive full-system model was built to answer this question. Our first key finding is that the upfront capital cost of the PV systems being compared has the biggest impact on overall system cost. Hence, due to the higher upfront capital cost of residential SSEG systems, these systems increase the overall system cost. However, because of the added locational value of residential SSEG, the system cost increase is *not* significant. A second important finding is that, in most cases, commercial and industrial SSEG reduces the overall system cost. As such, we find that SSEG has immense value for the South African power system. We therefore argue that the private sector should receive increased policy support and incentive to invest in SSEG alongside an accelerated rollout of utility-scale PV.

Keywords: Embedded generation; solar PV; system cost; cost-reflective tariffs.

1. Introduction

South Africa's latest integrated resource plan describes a rapid solar photovoltaic (PV) build programme, with 7 gigawatts of new capacity being built by 2030. The plan anticipates that the vast majority of this capacity will be built in the form of utility-scale solar PV plants in areas of highest solar resource.

The recent proliferation of small-scale embedded generators (SSEG), is creating new options for the delivery of key electricity services, including alternatives to transmission or distribution network investments. Rooftop solar PV is the most common form of SSEG, but these can include any generator or energy-storage device connected to a load in the distribution network and characterized by relatively small capacities (e.g., a few kilowatts to a few megawatts). The term SSEG is interchangeable with the term distributed energy resource, or DER. Estimates on South Africa's total SSEG installed capacity vary from 500 megawatts to over 1 gigawatt, and this capacity is rapidly growing, making SSEG a notable part of the country's generation mix [1].

SSEGs can deliver the same services provided by equivalent utility-scale generators. Additionally, because of their distributed and modular nature, SSEGs can provide these services at locations in power grids where they are most valuable. If sited at the right locations and utilised at the right times, SSEGs can deliver more locational value than utility-scale generators [2]. However, due to the economies of scale, SSEGs tend to cost more on a per-unit basis than utility-scale generators.

As such, SSEGs offer new options and trade-offs for power system planners, policy makers, and regulators. How should decision makers weigh the additional value and additional costs of SSEGs when considering how to deploy them in the most societally beneficial manner? And how should this value be captured? This paper addresses this question by making a first stab at understanding the trade-offs between embedded generators and their utility-scale counterparts from an overall system cost perspective. Accurately modelling an electricity system is a highly complex challenge, and as such we have focussed on the major system-cost impacts. The socio-economic impacts of SSEG have not been explored here but should form part of the ultimate policy direction.

1.1. System Cost Planning

South Africa's latest integrated resource plan of 2019 considers SSEG to be a demand-reducing intervention and therefore states that SSEG was modelled in the low-demand scenario [3]. However, to properly understand the potential benefits of SSEG, it is important to consider the system-wide cost implications when compared to a scenario of centralised utility-scale PV.

Regulated, vertically integrated electric utilities, have a long tradition of employing capacity planning models to help determine investment and retirement decisions and to justify their decisions to regulators [4]. These mathematical models are designed to determine the least-cost mix of electricity generating. By around 2010, the steady increase in wind and solar energy penetration spurred substantial research into the integration of high shares of variable renewable energy sources into power systems [5]. However, only very recently have a handful of studies granularly modelled the distribution grid as opposed to simply considering distribution grids as loads [5]–[7]. These studies show that modelling the cost of distribution grids is critical to quantify the whole-system value of SSEG.

The value of electricity generators varies depending on where they are connected to the grid. For SSEG to compete with utility-scale solar PV, the additional locational value obtained by deploying distribution-level generation must outweigh the opportunity cost of not capitalizing fully on economies of scale.

1.2. Locational Value

SSEGs compete with conventional generation and network assets to provide electricity services. In this sense, they are no different from other options for electricity service provision. What distinguishes SSEGs is their ability to generate electricity closer to the point of electricity consumption and in locations inaccessible to more centralized generators. This capability is important because the value of some electricity services changes with the location of provision. This difference in locational value emerges from the physical characteristics of electricity networks, including resistive losses and capacity limits of network components. Three primary electricity services constitute the bulk of locational value: electrical energy (i.e., reducing losses through transportation), distribution and transmission network capacity (or non-wire alternatives to network capacity), and, when peak demand is reduced, peaking power plant capacity. A fourth locational value that is not modelled here is the enhanced reliability or resilience to power outages. Each of these locational values of SSEG will be discussed in more detail in sections 1.2.1 to 1.2.3.

1.2.1.Locational Value of Energy

Because of the impact of network losses and congestion on electricity networks, the value of electrical energy consumption or injection varies at different points in the power system. SSEGs have the potential to create significant value by supplying energy (or reducing net consumption) at locations where networks are frequently constrained and marginal losses on transmission and distribution systems are large [8].

In South Africa, electricity losses in distribution networks typically ranges from 8 to 11%, with a further 3% of energy being lost through high-voltage transmission [9]. Therefore, by virtue of their location, SSEGs avoid these network losses adding value to each unit of energy generated [2].

1.2.2.Deferred Distribution Network Investments

When SSEG generation coincides with the building's peak demand it can *permanently* reduce the building's peak demand. Figure 1 shows how SSEG has reduced the peak demand of various building types. A reduced peak demand reduces the utility's capacity costs by extending asset lives and deferring network investments.

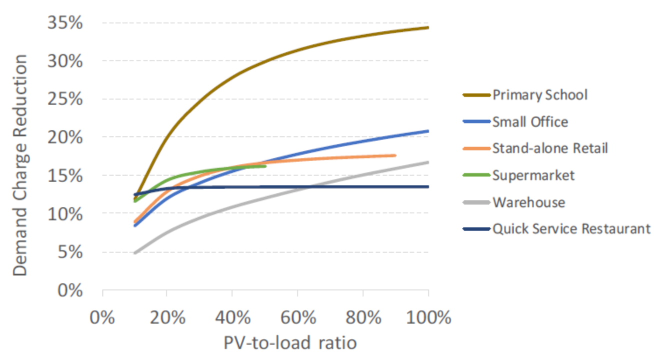

Figure 1: Commercial buildings demand charge reduction with increasing PV system size for various building types in Los Angeles [10]

1.2.3.Avoided Transmission Infrastructure Developments

Areas of highest solar resource are often far from load centres, meaning that transmission infrastructure needs to be built to transmit the power from utility-scale solar farms in the desert to the cities where the power is consumed. By connecting directly to the load, SSEG avoids the need for these transmissions infrastructure developments and thereby reduces system cost.

1.3. Economies of Scale

Although SSEGs may be sited in the power system to capture additional locational value, there are economic trade-offs associated with the smaller sizes of these distributed resources. The unit costs of energy technologies typically fall as the technology is installed at larger scales. Therefore, a 50-MW system of a given technology will typically cost less per megawatt than a 5-MW system of the same type, which, in turn, will cost less per megawatt than a 5-kW system. Many technologies suitable for distributed deployment, including solar PV and energy storage, harness modular technologies that can enable them to be deployed across a wide range of scales.

Nonetheless, these technologies exhibit clear economies of scale meaning that smaller systems result in higher per unit costs than larger-scale installations [11]. In South Africa, the cost per unit, measured in R/kWp, of a residential SSEG system can be more than double that of a utility-scale solar PV system [12].

1.4. Research Objective

The paper presents an analysis of the locational value of SSEG in the South African power system for different levels of SSEG penetration considering the electricity load profiles of potential SSEG adopters in different sectors of the economy.

2. Methodology

The analysis is conducted using a system model of the South African power system. The model quantifies the annual system costs in 2030, 2040 and 2050, given a projected demand and system configuration for those same years. The annual system cost includes investment (annualised), and operation costs for the generation, transmission, and distribution components of the system. In cases where SSEG (rooftop PV) is included, the investment and running costs are included in the system cost calculation. The quantification of the locational value of increased levels of SSEG in the system is computed by taking the difference in system costs between the system with X MW of SSEG installed and a corresponding system with the same X MW of utility scale PV installed instead.

The model is made up of five main components, a calibration component, an annual energy demand projection component, a simple distribution level dispatch component, a simple grid expansion and dispatch component, and a cost calculation component, which are all hard linked in an Excel workbook.

2.1. The Calibration Component

The calibration component includes subcomponents focusing on the energy balance, the demand profile, and the costs.

2.1.1.Energy Balance Calibration (Electricity only)

This component combines hourly data from Eskom[1] and the municipalities to estimate electricity consumption by households, commercial buildings, industry (including mining) and other (agriculture and rail transport) for 2018 which would result in the full energy dispatch observed by grid-based power plants in the same year.

2.1.2.The Demand Profile

This component scales sector profiles from Eskom load research by the energy consumption by the different sectors to match up with the observed dispatch profile of grid plants in 2018.

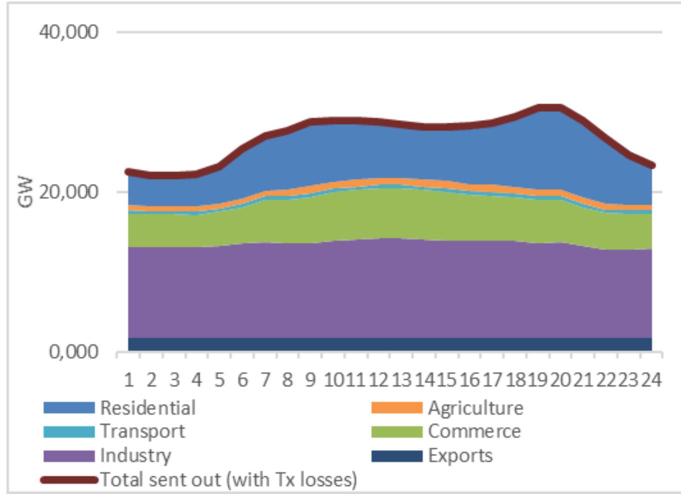

Figure 2: Demand by Sector for the Average Day in 2018

2.1.3.Costs

This component uses Eskom's Revenue Application 2018/2019 to reconstruct the generation, transmission, and distribution cost of the electricity system for 2018. Distribution costs for municipalities are estimated based on Eskom distribution costs.

2.2. The Annual Demand Component

The annual demand component projects energy demand at a sectoral level as follows:

2.2.1.Residential

The residential sector is split into two different income groups, where it is assumed that only the high-income group would consider installing SSEG rooftop PV. Roughly 18% of the population, consuming around 54% of the total electricity demand in the residential sector, would fall in this category in 2018 [13]. Electricity demand in 2030 is projected by making assumptions on the number of high-income households, how their monthly consumption will evolve and how the average monthly consumption of the lower income group will evolve. In the cases considered here, the SA population is assumed to reach around 65m in 2030 [14] and with 25% households in the higher income group. The average monthly electricity consumption of both income groups is assumed to remain constant over the period.

2.2.2.Commercial

The commercial electricity demand is linked to the total floor space of commercial buildings and the average per m^2 intensity. The commercial floor space is split into "existing" and "new". In cases presented here, it is assumed that the overall commercial

[1] Eskom, personal communication. Hourly data does not adequately represent the power system, but it is the best available data.

floor space grows 1% annually and that 5% of the existing floorspace would have been "retired" by 2030. The kWh per m^2 intensity for existing buildings is assumed to drop by 10% in 2030 relative to the 2018 level, and the "new" commercial buildings is assumed to have a much lower intensity (200[2] kWh/m^2) in 2030 based on proposed building standards [15].

2.2.3.Industry

Industry demand growth is simply assumed as 1% per year to 2030.

2.3. The Distribution Level Dispatch

This component takes the projected energy demand for 2030 and scales up sectoral profiles to arrive at the total demand profiles "seen" by the grid. Should SSEG be installed in a particular sector, the SSEG is dispatched using hourly solar profiles[3] and subtracted from the demand profile in the calculation of the demand profile "seen" by the grid.

2.4. The Grid Expansion and Dispatch Component

This component takes the demand profile "seen" by the grid and simultaneously does an Energy Balance and Capacity Balance for the grid-based power generation system as follows:

2.4.1.Energy Balance

The user exogenously specifies how much coal, nuclear, PV, Wind, CSP, Pumped Storage and Battery Storage capacity will be in place in 2030. The coal, nuclear, PV, Wind and CSP capacity is dispatched as per the historical dispatch profile observed in 2018, and this dispatch is subtracted from the overall demand profile. The profile is "flattened" using available pumped storage capacity and the remaining profile is met with gas turbines.

2.4.2.Capacity Balance

The user specifies a *Reserve Margin* requirement for the system. The peak demand is derived from the demand profile. The installed gas turbine capacity is calculated such that total *firm* capacity of the system is equal to peak demand *(1+ Reserve Margin). Firm capacity only includes dispatchable generators.

The generation dispatch to meet the total demand is shown in Figure 3. Note that when the generation curve is below zero, this is when the pumped storage is charging/pumping. The light blue area then illustrate when the pumped storage is discharging/generating.

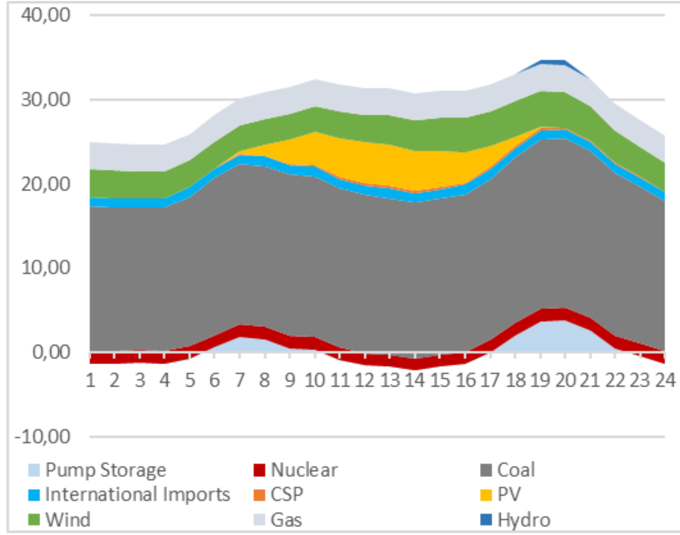

Figure 3: Generation Dispatch for the Average Day in 2030

2.5. The Cost Calculation Component

This component calculates the total annualised system cost for the system in 2030. The system cost is the sum of investment and operation costs for the generation, transmission, and distribution systems.

2.5.1.Generation Costs

Annualised investment cost is overnight cost + interest during construction, annualised using the global discount rate (8.2%) and the lifetime of the plant. Based on Eskom's 2018/2019 Revenue Application, there is a residual "investment cost" for the existing fleet of power plants. The assumed costs for new power plants are mainly based on the IRP 2019, with some learning for PV and Wind.

The fixed maintenance cost for existing plants is calculated using the installed capacity and the unit cost derived in the cost calibration component. The fixed maintenance cost for new plants is based on capacity for new plants and assumed maintenance costs.

The variable maintenance costs and fuel costs are calculated using assumed fuel prices and variable maintenance cost for different technologies in the system and the dispatch profile calculated above.

2.5.2.Transmission Costs

There are two components for Transmission costs, namely one linked to the overall system peak and one linked to the total installed capacity. The second component is ensuring that adequate grid infrastructure is in place to support large

[2] Conservative assumption with actual building efficiencies being considerably lower

[3] SolarGIS data

penetrations of renewable energy. Unit investment and maintenance cost for demand linked transmission is derived in the cost calibration component.

2.5.3.Distribution Costs

Distribution costs are calculated for the different sectors based on the observed peak in each sector and the unit investment and maintenance costs derived in the cost calibration component. We did not consider distribution grid constraints in accommodating SSEG and as such these grid reinforcements were not modelled.

3. Results

To determine the value of SSEG uptake in various sectors, three separate experiments were performed: residential SSEG, commercial SSEG, and industrial SSEG. In all three experiments, the SSEG penetration was increased and the annual system costs in 2030 were compared to a system without SSEG, but with equal amount of utility-scale solar PV.

Table 1 lists the key assumptions for each experiment:

Table 1: SSEG Cost Assumptions (2018 Rands)

	Utility PV	Resi. SSEG	Comm. SSEG	Ind. SSEG
Invest. Cost 2018 (R/kW_P)	14 000	28 500	16 800	16 800
Invest. Cost 2030 (R/kW_P)	9 500	16 150	10 450	10 450
Maint. Cost 2018 (R/kW/yr)	280	856	336	336
Maint. Cost 2030 (R/kW/yr)	190	323	209	209
CF	25%	20%*	20%	20%
Avoided Dx Losses	0%	20%**	12%	6%
Demand Load Shift	0%	20%	15%	15%

*This is an optimistic CF assumption.
**This may be an inflated avoided losses assumption that includes unavoidable non-technical losses.

3.1. Residential SSEG Impact on System Cost

The first experiment modelled the uptake of SSEG in the residential sector. We modelled an average SSEG system of 2.5 kW_p, and Figure 4 shows the impact of an increasing share of high-income residential households installing SSEG. The model finds that residential SSEG without load shifting (blue line) increases system cost when compared to utility-scale solar PV. There are many reasons for this, but it is largely due to the higher per unit cost of these smaller systems, as well as the misalignment of solar generation and residential peak demand.

However, when residential SSEG is coupled with shifting 15% of the customer’s load into the daytime, the model finds that the system cost can be reduced. Load shifting can be achieved using simple behaviour change or with technology like batteries or timers on devices: the cost of which was not modelled here. It must be noted that load shifting alone has significant value to the system (as shown by the orange line at 0% penetration).

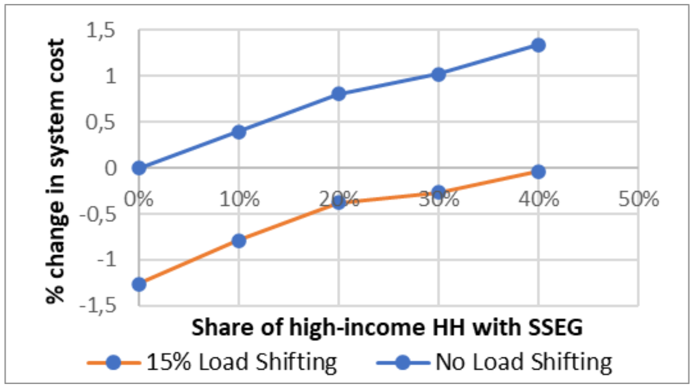

Figure 4: The system cost impact of increasing amounts of residential SSEG

At the point of 20% penetration, the cumulative capacity is 2.3GW, and the system cost of residential SSEG with load shifting is slightly lower than utility-scale PV. Figure 5 presents a waterfall graph of this point to show the difference in the system cost impact of a system with 2.3 GW residential rooftop SSEG vs 2.3 GW of utility scale PV. The first orange bar of R2.53 billion shows the upfront capital cost of 2.3GW of utility-scale PV, which is significantly lower in cost than the blue bar (R4.2 billion) showing the upfront cost of 2.3 GW of residential SSEG. However, for the utility-scale PV to provide the same service as the SSEG with load shifting, peaking gas power plants are required (R0.51 billion), and electricity losses need to be covered by fuel (R0.4 billion). Further to this, transmission infrastructure reinforcements are required to meet the increased peak demand (R0.18 billion), and to transmit the solar PV power to load centres (R0.26 billion). The final cost component is the distribution network upgrades to supply the growing peak demand (R0.73 billion), which is avoided when customers install SSEG with load shifting and reduce their peak demand.

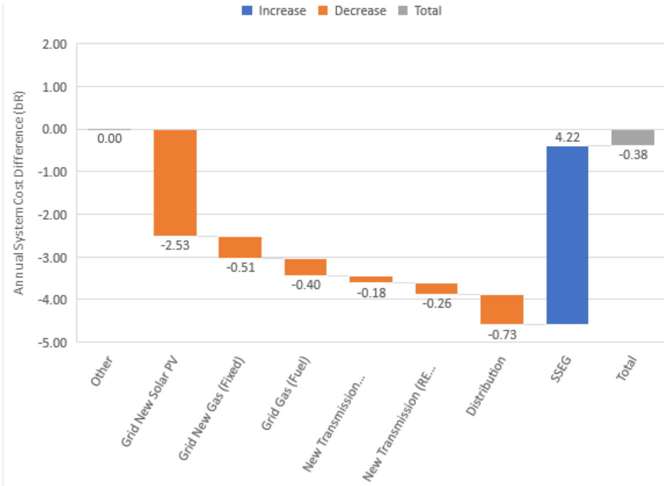

Figure 5: Breakdown of System Cost Impact of 2.3GW Residential SSEG with Load Shifting

This experiment has shown that the upfront capital cost of the systems being compared has the biggest impact on system costs. Secondly, without load shifting, residential SSEG increases system cost. However, a key finding is that when residential SSEG is coupled with load shifting, system cost can be reduced.

3.2. Commercial SSEG Uptake Impact on System Cost

The second experiment modelled the uptake of commercial SSEG. This experiment was done differently to the residential sector in that the SSEG penetration was kept constant at 40% of the sector's peak demand. Since peak demand reduction is the driver of network infrastructure cost reductions, the assumed peak shaving was incrementally increased to determine the point at which system costs reduce to below that of utility-scale solar PV. As shown in Figure 8, when peak demand reduction exceeds 7%, the system cost drops below that of equivalent utility-scale solar PV.

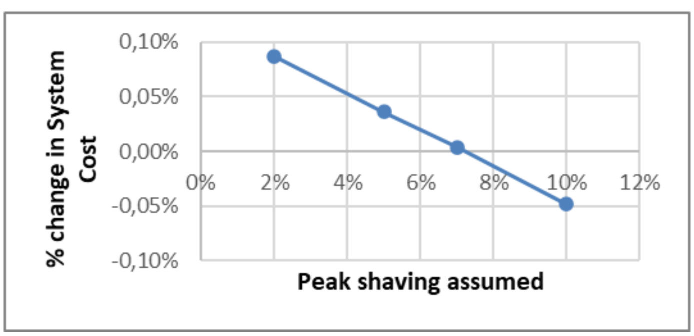

Figure 6: The system cost impact of increasing levels of commercial SSEG

To understand the ability of SSEG to reduce the commercial sector's peak demand, we modelled a PV generator on a synthetic hourly load for a full year. We found that even without load shifting, a 40% of peak SSEG system can reduce the commercial sector's peak demand by up to 12%. The peak demand reduction can be further reduced by up to 20% when the SSEG is coupled with 10% load shifting into the daytime, as shown by Figure 7. However, it should be noted that these figures are indicative of the commercial sector average, and different buildings would have different peak demand reductions – schools and offices would expect larger peak reductions than restaurants and hotels. Furthermore, the hourly data does not fully capture the intra-hour variation in both load and generation and in reality, advanced load control may be required to manage peak demand.

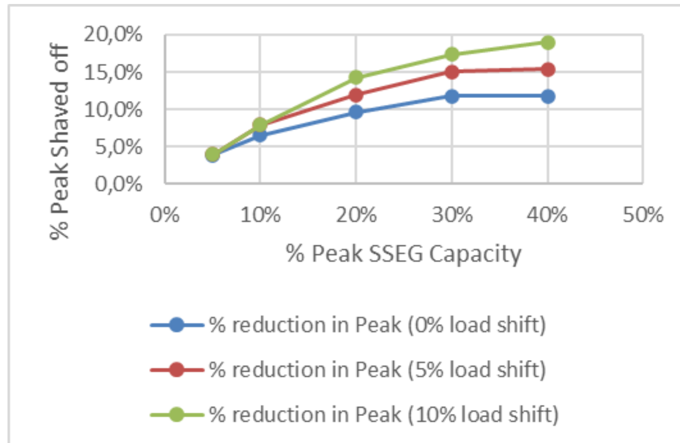

Figure 7: Commercial Demand Peak Reduction with increasing SSEG Penetration and various levels of Load Shifting

We modelled a conservative level of 7% peak shaving, meaning that the system cost impacts would be neutral (as shown in Figure 6Figure 7). The amount of SSEG is kept constant at 40% of peak, or 2.3GW of PV. Figure 8 presents the cost elements that contribute to the commercial SSEG system cost impact. The upfront capital cost of the 2.3 GW of SSEG is R3.03 billion (far-right blue bar), while the utility-scale solar PV is only slightly cheaper at R2.52 billion. As with the residential sector, these capital costs have the largest impact on overall system cost. Interestingly, the model shows that commercial SSEG increases the system's consumption of gas fuel by R0.14 billion (the small blue bar). This is because the gain in utility-scale PV capacity factor outweighs the avoided electricity losses by commercial SSEG (because commercial customers are typically connected at medium voltage which has lower losses than the residential sector). The peak demand assumptions are very conservative, and as such, the distribution and transmission infrastructure cost savings are relatively modest.

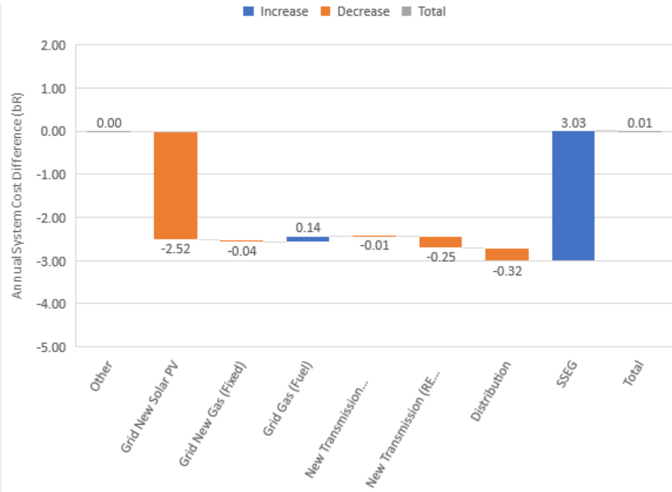

Figure 8: Breakdown of Commercial SSEG System Cost Impact

3.3. Industrial SSEG Impact on System Cost

The industrial sector has a relatively constant load, meaning that SSEG peak demand reductions are relatively low. Also, since industrial customers are connected at high voltages, SSEG avoids less electricity losses. However, since industrial SSEG installations can be very large, the economies of scale are better. As a result, the model finds that industrial SSEG has a neutral impact on the system cost, on average.

4. Discussion and Conclusion

The paper presents an analysis of the locational value of SSEG in the South African power system for different levels of SSEG penetration considering the electricity load profiles of potential SSEG adopters in different sectors of the economy.

The first major finding is that the upfront capital cost of the PV systems being compared has the biggest impact on overall system cost. Hence, due to the higher upfront capital cost of residential SSEG systems, these systems increase the overall system cost. However, with the rapidly declining capital costs of commercial and industrial SSEG systems, these systems compete well with utility-scale PV.

The second major finding is that the system cost is highly dependent on whether a SSEG system reduces the building's peak demand or not. As such, the model shows that SSEG in commerce (or any buildings with daytime peak demands) is most viable, and depending on level of peak shaving achieved, commercial SSEG systems can reduce the overall system cost.

A third key finding is that simply shifting load into the daytime, when solar PV is generating, reduces system cost considerably. Further, when residential SSEG systems are coupled with load shifting, even these systems can reduce system cost.

As such, we argue that electricity tariff design should reflect the value of a reduced peak demand by setting demand charges that reflect the distribution grid's peak demand i.e., coincident demand charges. Secondly, electricity tariffs should reflect the value of shifting load to cheaper generation periods by setting dynamic time-of-use tariffs for all high consuming customers.

While this paper has focused on the impact of SSEG on the total cost of the power system, there are several other non-financial impacts of SSEG. Few people dispute the fact that SSEG creates more jobs per MW installed than utility-scale PV. In addition, these jobs are within cities, nearer amenities, as opposed to jobs in the desert where the solar resource is best. Conversely, utility-scale systems can be rolled out much quicker, allowing for accelerated emissions reductions.

In conclusion, we find that, at worst, SSEG does not significantly increase the overall cost of the power system. Private sector investment in SSEG should therefore receive increased policy support alongside an aggressive state-coordinated rollout of utility-scale PV.

Acknowledgements

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