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Comparative analysis of services from soft open points using cost–benefit analysis

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ABSTRACT

Soft Open Points (SOPs) are power electronic-based devices which can replace Normally Open Points (NOPs) in distribution networks. They can improve network performance by enabling controllable power transfer between adjacent feeders. This flexible meshing can provide a wide range of services, including loss reduction, reduced renewables curtailment, improved reliability, reinforcement deferral, or enabling flexibility services. This paper proposes a novel framework, based on the Cost–Benefit Analysis methodology, to quantify and compare the cost-effectiveness of SOPs for providing each of these five value streams. The framework includes the development of mathematical models that encapsulate the key variables that drive competitive SOP use cases, as well as providing detailed analysis to determine quantitative estimates for each of the parameters. Results suggest that, whilst all services could be cost-effective, that reinforcement deferral and reduced DG curtailment are most likely to find wide usage. It is also suggested that the fast response time of SOPs as compared to conventional NOPs is unlikely to be a viable value proposition for improving reliability via conventional loss of load metrics such as energy not supplied. A detailed case study demonstrates that in marginal cases, where a SOP has a similar system net benefit compared to Business-as-Usual, that all services need to be considered rather than just single value streams in isolation. It is concluded from the research that there are multiple potential competitive applications for SOPs in future distribution networks.

1. Introduction

A transformation in the planning and operations of electrical distribution networks is necessary for power systems to reach net zero. These changes are needed to support consumers as they adopt low carbon technologies such as electric vehicles, heat pumps and solar PV. One technology which has shown significant recent interest as part of this evolution is the Soft Open Point (SOP) [1], a technology designed to replace Normally Open Points (NOPs) with flexible power electronics (typically back-to-back voltage source converters). Installing SOPs allows distribution networks to be operated in a 'soft meshed' configuration, enabling benefits such as new network capacity, loss reduction, or voltage control without requiring the expensive upgrade of protection or switchgear [2,3].

Research into the use of SOPs has primarily focused on operational or placement issues to calculate technical benefits [3]. For example, in the seminal works [2,4], the authors discuss how a SOP can provide benefits to the distribution network when the network is in a post-fault condition. In [5], the authors consider how the equivalent capacity value of SOPs can be calculated, whilst the potential for SOPs to reduce voltage unbalance is demonstrated in [6,7]. As SOPs can respond much more quickly than traditional reconfiguration technologies, papers often consider SOPs as a means of supporting supply restoration (i.e., improving consumer reliability) [8,9]. Some authors treat SOPs as a means of 'transacting' energy between regions, with [10,11] considering peer-to-peer trading mechanisms that make use of SOPs. SOPs have even been considered as a means of mitigating against the risk of cyber attacks [12], or as a component of an Active Distribution Network scheme [13,14]. However, despite it being well-known that power electronic capacity is typically expensive compared to Business-as-Usual solutions [15], there are very few works that explicitly monetize those technical benefits to determine the viability of SOPs via an appropriate decision making tool [3]. Without an understanding of the most promising services for SOPs, SOPs risk remaining an academic curiosity rather than a versatile and flexible component of a Distribution System Operator's (DSO's) toolkit.

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1.1. Literature review and gap analysis

The relatively small number of studies that consider SOPs in the context of network planning has been noted in recent works [16,3]. Planning-focused papers typically considering just a single value stream or project in a high level of technical detail, rather than comparing the benefits in the context of the suite of potential services SOPs can provide. The cost-effectiveness of SOPs and remote-controlled switches is considered in [17], focusing on cost savings due to a reduction in energy not supplied. The industry-led 'FUN LV' project undertakes a Cost–Benefit Analysis (CBA) for SOPs, although the scope of the CBA was limited to the consideration of reinforcement deferral benefits [18]. In [16], the authors consider the optimal planning and placement of SOPs for enhancing resilience of a distribution network that is vulnerable to typhoons, considering power losses and lost supply (i.e., costs due to energy not supplied). Similarly, the authors of [19] site and size SOPs based on investment costs, operational costs, and power losses. Other works, such as [20] consider planning in a system with SOPs, but focus on energy storage sizing as the main objective for the network operator.

Other papers consider the SOP planning problem under uncertainty. In [21], the authors consider a multi-objective stochastic optimization approach for sizing and siting of SOPs. Real Options have been considered for SOPs in a number of contexts (through determination of 'Option Value'), including as a stand-alone device [22], as combination with other smart technologies [23], or in combination with a portfolio of energy storage [24]. Should high quality forecasts and data allow the modelling of stochastic load growth, then using the Real Option methodology can yield highly accurate estimates of the net present value (NPV) under uncertainty. However, these approaches are unlikely to change the NPV of a project substantially (i.e., a project which has a large, negative NPV will not become viable due to the consideration of uncertainty, and vice versa) [25]. Therefore, the complex, sophisticated modelling required to perform Real Options analysis is considered unsuitable for the comparative framework considered in this paper. Other alternatives to CBA for decision making (e.g., multigoal analysis, qualitative CBA, distributionally weighted CBA) are effective when there are substantial uncertainties in valuation of societal impacts, or when the choice made has a considerable non-monetary factor associated with it (e.g., if there is a major political risk associated with a project) [26, Ch. 2.5]. CBA is the simplest and most effective tool for a DNO to use as these two factors are not significant—well-established methods exist for consideration of social factors (e.g., the economic cost of power outages on different consumer types), and DNO's role as a regulated monopoly ensures their primary goal is to provide value-for-money to consumers.

In summary, whilst topics around the planning of SOPs have been considered in a number of specific contexts, there are no works that propose approaches to meaningfully compare the viability of SOPs for providing the range of services that are possible. Given the range of applications for SOPs [3] and need for improved network performance in the coming decade [27], this is a considerable and timely gap.

1.2. Contribution and novelty

The main overall contribution of this work is to address the gap identified in Section 1.1. Specific contributions for the paper are both methodological and model-based, as follows.

- Firstly, the methodological contribution is the development of a CBA-based comparative framework. This is used to study and consider the viability of SOPs for five key SOP value streams, namely loss reduction, reduced curtailment, reliability improvement, reinforcement deferral and congesting management to enable flexibility. This enables an identification of critical parameters that drive viable projects.
- Secondly, models are proposed and data collected to study the viability of SOPs for those five value streams. Upper, lower and central estimates of critical model parameters are identified for each of the value streams, aiming to capture the widest range of network conditions.

The combination of the proposed framework, models and data will enable researchers, analysts and decision-makers to identify and understand the most promising applications for SOPs, whilst additionally providing a structure for considering further potential use-cases of SOPs and other smart grid technologies.

Viability is evaluated using both net present value and the SOP cost parity point (i.e., the required unit cost of power electronics that would be required to reach a break-even point). Note that the proposed framework is most suited to be used as an exploratory technique, exploring how system parameters impact on the viability of projects. Should a DNO be considering installation of a SOP, then appropriate technical planning procedures will need to be considered. Nonetheless, processing the output of such planning procedures will yield the parameters proposed in this framework, enabling a planner to consider how the proposed SOP's location compares to the range of all SOP projects that are potentially credible for a given service.

Both the methodological and modelling contributions of the work are novel. Comparative analyses have been considered for a number of local energy system technologies such as energy storage [28], electric vehicle batteries [29], grid-connected DC microgrids [30], microgrid energy management strategies [31], and even power-to-gas technologies [32]; such a framework has not been considered for SOPs. The CBA-based approach is well-suited to provide the basis for such a framework as it avoids complex stochastic formulations (e.g., using real options [23] or multi-objective comparative approaches [29]), is well-understood by utilities [33], and allows meaningful direct comparisons between the viability of value streams that SOPs can provide. It is also particularly suited when considering physical assets that DSOs might own, as DSOs are regulated monopolies and so have an obligation to provide value for money for customers. In comparison with other closely related papers that consider SOP planning and CBA [16,19], this work uses the proposed framework to compare a range of value streams, quantitatively considering the applicability of SOPs for a wide range of possible network services. Additionally, the novel combination of proposed, parsimonious models with appropriate system data has allowed for the comparative analysis to be undertaken for five value streams, where prior works focus only on one or two value streams.

The structure of this paper is as follows. In Section 2, we describe the proposed framework, detailing the CBA methodology and its application in the context of SOPs, showing how this determines SOP economic viability for each value stream. Mathematical models of the five value streams are then developed in Section 3, with each revealing critical parameters that determine viability of a given SOP proposal. The value of some of these parameters are not available from the literature, and so analytic techniques are proposed for determining upper, lower and central estimates of these parameters in Section 4. The estimated parameters and viability of each SOP value stream is explored in Section 5, including detailed case studies and a discussion, to highlight the results from the framework and consider its applicability beyond the analysis of SOPs. Salient conclusions are then drawn in Section 6.

2. Comparative analysis framework using cost–benefit analysis

The aim of this work is to provide and demonstrate a framework to enable comparisons of the viability of value streams provided by SOPs. In this section, we first describe the proposed framework to highlight how it enables a meaningful comparison between value streams. We then describe how the method adheres to the CBA methodology and present the metrics used to determine viability.

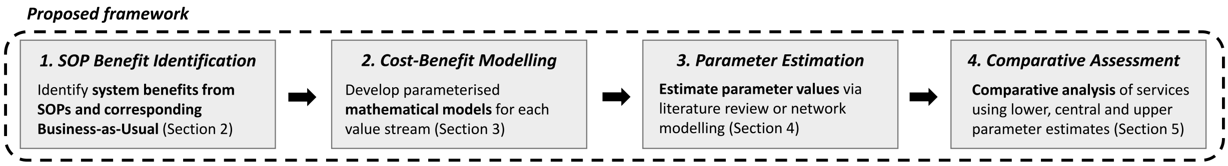

Fig. 1. The proposed four-step framework for the comparative assessment of SOP value streams.

2.1. Comparative analysis framework

The proposed framework for comparative assessment of SOP value streams is summarized in Fig. 1, and consists of four main components.

The first step of the framework is to identify the individual value streams of interest and the corresponding Business-as-Usual (as required for the CBA methodology, described in Section 2.2). Implicitly, in doing so, it is assumed that a SOP would be installed by a DSO for one key service. The framework assumes that if a project is highly attractive for one value stream, that the other value streams are likely to affect the economics in a relatively small way. There are two ways that such an assumption requires further analysis. Firstly, if a SOP project is only marginally viable for a given value stream (i.e., the project has a NPV that is close to zero), then the interaction between multiple value streams becomes much more important (as demonstrated in Section 5.3). Additionally, if there is a very strong link between a value stream which has a strong positive NPV which is countered by a second value stream that is equally strongly negative, then the result will require detailed modelling of both value streams in parallel. Multiple value streams therefore are unlikely to significantly impact on accuracy of the qualitative economic outcome (unviable, indeterminate, viable) from the comparative framework. In any instance, if a SOP project is considered potentially viable, a detailed technical appraisal would be necessary prior to investment. We also note that future work could also consider multiple value streams through a composite value proposition where there are strong interactions between value streams (e.g., previous works have considered interactions between generator reactive power control to reduce solar curtailment and impacts of the subsequent increased line losses this causes [34]).

In the second stage, mathematical models are determined that capture the key parameters that determine the cost-effectiveness of the device from the system level. These models need to summarize the key drivers and uncertainties that drive system-level benefits and costs. Following the principle of parsimony, these models should have mathematical simplicity to clearly highlight these drivers.

Next, estimates of each of the critical parameters need to be determined. The approach considered in this work is to use a scenario-based approach, considering lower, central and high estimates of each of these parameters. Such an approach deliberately avoids quantification of uncertainty, instead using these estimates for sensitivity analysis to explore how outcomes can change for a range of network types and future system evolutions (e.g., prices). It is worth noting that this sensitivity analysis is used for energy system decision making today, even in mid-term decision making as close as one year ahead (e.g., in the context of the UK capacity market [35]).

Finally, the estimated parameters are combined with the models of the net benefits of each value stream to determine how economic viability varies between value streams. Lower, higher and central estimates can be used to estimate credible ranges of net present value, and the SOP unit cost that would lead to a marginally viable project for each value stream.

2.2. Cost–benefit analysis

A CBA can be defined as [26, Ch. 1] *a policy assessment method that quantifies in monetary terms the value of all consequences of a policy to all members of society*, where 'policy' refers to an initiative such as a project or strategy. The key metric of the CBA is the total net social benefit, taken by comparing all costs of proposed projects against a benchmark case [26,36].

The steps required to undertake a Cost–Benefit Analysis can be summarized as follows. The proposed (SOP) and benchmark (Business-as-Usual, BaU) cases are defined for a given project. Based on this, the costs and benefits of the SOP and BaU options are calculated; finally, the Net Present Value (NPV) of the benchmark and proposed cases are compared to determine the project which maximizes the social welfare (i.e., has the greatest NPV). Sensitivity analysis can then be conducted to identify impacts of uncertain parameters. This approach has informed the comparative framework as outlined.

The NPV of project Ω over N_t years with social discount rate r can be calculated as

$$\mathrm{NPV}^{\Omega} = \sum_{t=0}^{N_t-1} \frac{1}{(1+r)^t} \left(B^{\Omega}(t) - C^{\Omega}(t) \right) . \tag{1}$$

considering project costs and benefits as C^{Ω}, B^{Ω} respectively.

Furthermore, we also define the *cost parity* (CP) value for a SOP as an alternative way of considering SOP viability. For NPV of proposed SOP and BaU solutions as $\mathrm{NPV}^{\mathrm{SOP}}$ and $\mathrm{NPV}^{\mathrm{BaU}}$ respectively, the CP is the SOP marginal cost C_α (in \$/kVA) for which the SOP changes from unviable to viable,

$$\mathrm{CP} = C_\alpha \quad \text{s.t.} \quad \mathrm{NPV}^{\mathrm{SOP}}(C_\alpha) = \mathrm{NPV}^{\mathrm{BaU}} . \tag{2}$$

In some ways, the CP is more informative than NPV. This is because it allows forecasts of future cost reductions in power electronics to be considered, enabling an analyst to understand if a project based on a given value stream is ever likely to become viable. Typical values of the marginal costs of SOPs C_α are typically in the range of 100–400 \$/kVA [37,15,17].

If a SOP of size α has net benefits B that are constant over the lifetime of a project, then the NPV can be rewritten

$$\mathrm{NPV} = \tilde{N}_t B - C_\alpha \alpha , \qquad \tilde{N}_t(N_t) = \sum_{t=0}^{N_t-1} \frac{1}{(1+r)^t} . \tag{3}$$

For example, for a discount rate r of 3.5% and SOP lifetime of 10 years the value of $\tilde{N}_t = 8.54$; an annual net benefit B of \$1000 yields a NPV of \$8540.

In this paper we consider five value streams, shown in Table 1 alongside each project's BaU. Note that this only shows the DSO BaU approach, i.e., DSO current or near-future practise. This BaU will not be unique in general, as each service can be provided by other alternative solutions (e.g., energy storage). Detailed outlines describing the mechanism by which each services provide a system benefit are presented in Section 3.

These five value streams were selected as they account for future distribution system needs of resilient, efficient and flexible network capacity. Furthermore, these services also capture the applications considered in previous works [16,18,19] and the benefits of the use-cases of the recent review [3].

Note that these value streams are distinct from the technical benefits themselves, however–the value streams represent the monetization of the SOP impacts as required for the CBA [26]. For example, feeder balancing leads to both a reduction in losses, and can address network

Table 1
Five value streams considered in this work.

Value stream	Business-as-usual (BaU)
Loss reduction	No SOP
Reducing curtailment	No SOP
Reliability improvement	NOP automation
Enabling flexibility	No SOP
Reinforcement deferral	Network reinforcement

congestion; or, reinforcement deferral can be driven by a need for voltage regulation, to address thermal congestion, or to deal with high levels of voltage unbalance. Note that we focus on AC grid services, although we note SOPs can also create microgrids (i.e., the SOP can allow formation of electrical islands). Future works could consider the CBA tool applied to such novel situations.

3. Estimating benefits of SOP value streams

Although contemporary, smart technologies can provide a wide range of services, in practice the implementation of new technologies is often focused on the exploitation of a single, high-value revenue stream (as discussed in Section 2.1). In this section, we consider five candidate value streams for a SOP that have been identified (Table 1). The mechanism by which each value stream provides a system benefit is outlined. Subsequently, mathematical models are described that capture the critical parameters used to study SOP viability for each service.

3.1. Loss reduction

The NPV for a SOP of size α that is acting to reduce losses, $\mathrm{NPV}_{\mathrm{Loss}}$, can be determined as

$$\mathrm{NPV}_{\mathrm{Loss}} = \tilde{N}_t C_{\mathrm{Energy}} L_\alpha \alpha - C_\alpha \alpha \,, \tag{4}$$

where L_α is the annual average loss reduction per unit of SOP installed (in MWh/kVA-yr), C_{Energy} is the marginal unit cost of energy (in \$/MWh), and $\tilde{N}_t$ is as defined in (3). As the BaU case is for no SOP installation, the cost parity point for loss reduction $\mathrm{CP}_{\mathrm{Loss}}$ is

$$\mathrm{CP}_{\mathrm{Loss}} = \tilde{N}_t C_{\mathrm{Energy}} L_\alpha \,. \tag{5}$$

The cost parity is high for projects where a SOP has a long lifespan, when the SOP enables high rates of loss reduction, and when the system has high marginal energy costs.

The average annual losses reduction L_α will in general be a function of the SOP size α. As we describe in Section 4.1, it was found that the location and network characteristics are much more important than the size of the SOP, although it was found that smaller SOP sizes (100 kVA or smaller) are required for the highest values of L_α.

The cost of energy C_{Energy} varies considerably depending on the system and season. For the purposes of this work, gas is assumed to be the marginal fuel (as is the case in countries such as the UK). Lower, central and upper estimates of this parameter are assumed to be 25, 54 and 100 \$/MWh based on UK government long-term forecasts [38].

3.2. Reducing curtailment of variable renewables

The second benefit that is considered is that of a reduction in the curtailment of variable renewables. If a SOP can transfer power to increase the output from DERs (e.g., solar PV) then this reduces the output of high-cost marginal generators. Note that it is implicit that the SOP is located at a place in the network for which it can support additional power transfer by the generator. For example, a SOP could be installed at a NOP adjacent to a DER–if the NOP cannot be dynamically reconfigured during normal operation, the SOP will be able to transfer power to the neighbouring feeder that was not possible for the Business-as-Usual case.

The NPV for reduced curtailment, $\mathrm{NPV}_{\mathrm{DG}}$, can be calculated from the grid energy cost of C_{Energy}, reduced curtailment per unit SOP G_α (in MWh/kVA-yr), SOP size α and number of years with a congestion N_{DG}

$$\mathrm{NPV}_{\mathrm{DG}} = \tilde{N}_t(N_{\mathrm{DG}}) C_{\mathrm{Energy}} G_\alpha \alpha - C_\alpha \alpha \,, \tag{6}$$

where the function $\tilde{N}_t()$ is as-defined in (3).

Comparing Eqs. (4), (6) it can be seen that the monetization of the curtailment and loss reduction value streams are very similar. However, the stakeholders and mechanism by which these two value streams provide a benefit are different (e.g., loss reduction benefits are socialized, where curtailment avoidance largely benefits the generator who can increase their export). Therefore, for the purposes of this work, these value streams are kept distinct.

Industry reports highlight that the amount of curtailed energy can be as high as 76% for individual plants across multiple years [39]. Given this, assuming a capacity factor for renewables between 10% and 30%, we assume low, medium and high levels of curtailment to be 1%, 5% and 12.5% across the whole year. This yields marginal DG curtailment reduction rates G_α of 0.09, and 0.44 and 1.1 MWh/kVA-yr, respectively. Given that planned distribution system reinforcement may relieve congestion, it is assumed that 3, 6 and 10 years might be low, medium and high numbers of years N_{DG} that a generator might expect significant levels of curtailment.

The cost parity for reduced curtailment $\mathrm{CP}_{\mathrm{DG}}$ is

$$\mathrm{CP}_{\mathrm{DG}} = \tilde{N}_t(N_{\mathrm{DG}}) C_{\mathrm{Energy}} G_\alpha \,. \tag{7}$$

This equation shows that the cost parity is high when energy costs are high, the rate of curtailment is high, and when network congestion is expected to remain for a long period of time.

3.3. Improving reliability

By reducing the severity or likelihood of outages, a SOP can reduce the societal cost of network failures. For example, sub-second SOP response times allow rapid reconnection, where NOP manual reconfiguration may take a number of hours. It is worth noting, however, that the difference between fully automated NOPs and SOPs is measured in hundreds of milliseconds [9], and so this benefit will most likely be found where reconfiguration is not possible (or when the highest levels of power quality are necessary).

For a given Expected Energy Not Supplied (EENS, in kWh/yr) and Value of Lost Load (VoLL), C_{VoLL}, the expected annual cost associated with circuit outages $C_{\mathrm{Rlty.}}$ is

$$C_{\mathrm{Rlty.}} = C_{\mathrm{VoLL}} \times \mathrm{EENS} \,. \tag{8}$$

Even if the shortfalls are relatively infrequent, the high values of C_{VoLL} mean that changes in reliability can lead to considerable changes in NPV. In this work, we use C_{VoLL} of \$20/kWh [40]. Note the that reliability improvement value stream is based a broad definition of reliability as a risk metric measured through EENS (i.e., based on both likelihood and severity) rather than just the reliability as an availability (as a likelihood).

The EENS can be estimated by calculating failure rates of equipment, repair times, and considering the load duration curve (LDC) of a given network. For the purposes of this work, this EENS can then be used to determine the outage utilization of the SOP μ_α in kW/kVA, which determines the rate at which the SOP reduces outages when the network is unavailable. For example, if a 500 kVA SOP can reduces the demand disconnected by 200 kW on average when there is an outage, then the outage utilization μ_α is 0.4 kW/kVA.

Therefore, for a network with unavailability U (in h per year) and SOP outage utilization μ_α, then the NPV of the reliability benefit $\mathrm{NPV}_{\mathrm{Rlty.}}$ is

$$\mathrm{NPV}_{\mathrm{Rlty.}} = \tilde{N}_t U C_{\mathrm{VoLL}} \mu_\alpha \alpha - C_\alpha \alpha \,. \tag{9}$$

In general, estimating the unavailability U and the SOP utilization μ_α during outages is not trivial, and is discussed in more detail in Section 4.

The cost parity for projects improving reliability $\mathrm{CP}_{\mathrm{Rlty.}}$ is

$$\mathrm{CP}_{\mathrm{Rlty.}} = \tilde{N}_t U C_{\mathrm{VoLL}} \mu_\alpha \,, \tag{10}$$

showing that SOPs are most useful when the VoLL, unavailability and SOP outage utilization are high. Note that DNOs are often incentivized by regulators to ensure that the number and duration of outages experienced by customers stays within acceptable limits.

3.4. Reinforcement deferral

A SOP can reduce the NPV of reinforcement by deferring investment a number of years, due to the time value of money (1). For example, if a substation transformer installed 30 years ago has a useable lifetime of 10 years remaining, but new connections cannot be accommodated with the existing asset, then the Business-as-Usual approach would be to reinforce the substation by installing a new transformer. Alternatively, a SOP could be used to dynamically transfer demand to other less congested substations during peak hours, so the full useable lifetime of the transformer can be exploited. Even if the cost of the transformer is the same today and in ten years, the present value today is higher, due to the discount rate applied to future costs (1). For a SOP lifetime of N_t years, enabling mean load growth of G_N MW/yr, the NPV $\mathrm{NPV}_{\mathrm{Dfrl.}}$ can be calculated as

$$\mathrm{NPV}_{\mathrm{Dfrl.}} = \left(1 - \frac{1}{(1+r)^{N_t}}\right) C_{\mathrm{Reinf.}} - C_\alpha G_N N_t \,, \tag{11}$$

so the cost parity point $\mathrm{CP}_{\mathrm{Dfrl.}}$ is given by

$$\mathrm{CP}_{\mathrm{Dfrl.}} = \left(1 - \frac{1}{(1+r)^{N_t}}\right) \frac{C_{\mathrm{Reinf.}}}{G_N N_t} \,. \tag{12}$$

Unsurprisingly, cost parity is proportional to reinforcement costs $C_{\mathrm{Reinf.}}$, but it is also inversely proportional to the mean load growth G_N. The latter is due to the fact that larger load growth implies that a larger SOP will be required to have the same reinforcement deferral benefit. Low, medium and high annual load growth is considered at 0.1, 0.4 and 0.8 MVA per year for 33/11 kV substations (estimates based on [41]). Note that the peak load here assumes either insignificant levels of demand-side response during peak load (as is typically the case today), or that this peak load is accounted for in the definition of peak load (e.g., if the 10% of demand at peak can be shifted, that the 'network peak demand' is 90% of the baseline peak demand).

The relationship between the project duration and cost parity is more complex. A longer duration project leads to a greater deferral of cost, but (assuming constant load growth) requires a larger SOP. It is shown in the Appendix that in this model (of constant load growth) that the differential of NPV with respect to project duration N_t is small—specifically, that

$$\frac{\partial \mathrm{CP}_{\mathrm{Dfrl.}}}{\partial N_t} \approx \frac{C_{\mathrm{Reinf.}}}{G_N} r^2 \,, \qquad \mathrm{CP}_{\mathrm{Dfrl.}} \approx \frac{C_{\mathrm{Reinf.}}}{G_N} r \,. \tag{13}$$

This means that small changes in the number of years ΔN_t such that $\Delta N_t r \ll 1$, there will be little change in $\mathrm{CP}_{\mathrm{Dfrl.}}$.

3.5. Congestion management for enabling flexibility services

SOPs can provide a service by enabling flexibility services. In particular, if a service required at a higher voltage level (e.g., network congestion at transmission) which can be mitigated by controlling DERs at lower distribution voltages, then a SOP can provide a service by addressing distribution system congestion to enable higher levels of participation from DERs. In other words, the SOP provides a service by enabling DERs to increase the amount of flexibility offered (see Fig. 2). For example, in the UK, the electricity system operator now procures a demand flexibility service [42], and network operators have tendered for more then 3700 MW of flexible capacity [43]. Restrictions to access to these markets due to network congestion represents an opportunity cost for potential market participants—the SOP alleviates this congestion to enable flexibility.

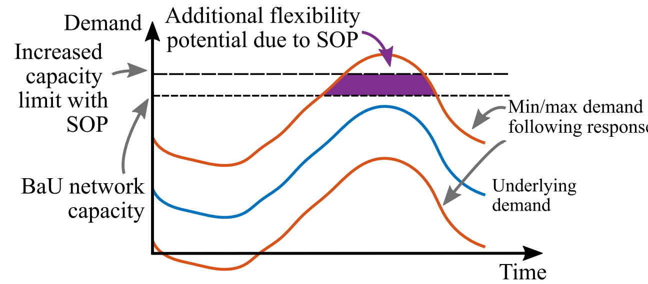

Fig. 2. Flexibility services provide value to energy systems by changing the temporal demand profile to improve system-wide performance (e.g., to alleviate transmission system congestion). By relieving network congestion, SOPs enable additional flexibility to be provided when required.

There are therefore two aspects to the benefit of enabling flexibility: the average potential increase in flexibility provision ρ_α (in MWh/kVA-yr), modelling the increase in flexibility that can be provided, and the value of the provision of the flexibility service $C_{\mathrm{Fbty.}}$. The value of the enabling flexibility service $\mathrm{NPV}_{\mathrm{Fbty.}}$ is

$$\mathrm{NPV}_{\mathrm{Fbty.}} = \tilde{N}_t C_{\mathrm{Fbty.}} \rho_\alpha \alpha - C_\alpha \alpha \,. \tag{14}$$

The corresponding cost parity $\mathrm{CP}_{\mathrm{Fbty.}}$ is

$$\mathrm{CP}_{\mathrm{Fbty.}} = \tilde{N}_t C_{\mathrm{Fbty.}} \rho_\alpha \,. \tag{15}$$

The SOP is an attractive solution when there is a high value service $C_{\mathrm{Fbty.}}$, and when the distribution congestion leads to a high potential increase in flexibility ρ_α

The central value of the flexibility cost $C_{\mathrm{Fbty.}}$ is calculated based on the high frequency Dynamic Containment service provided to the UK system operator, which has a mean value of \$2/MWh [44]. The upper and lower values of the flexibility $C_{\mathrm{Fbty.}}$ are estimated based on upper and lower curtailment values of a renewable plant G_α (Section 3.2), and the central estimate of the marginal energy cost C_{Energy}. This yields upper and lower estimates of \$0.54/MWh and \$6.8/MWh respectively.

The determination of the marginal potential increase in flexibility provision ρ_α is complex, as the congestion within an interconnected distribution network needs to be accounted for. This is discussed in more detail in Section 4.3.

4. Estimating framework parameters via optimal operation of a SOP

The services of loss reduction, increased reliability and enabling flexibility all require detailed modelling to determine the value of the parameters which can be passed into the comparative framework, as these parameters are not available from the literature. In this section we outline the modelling approaches used to achieve this aim for these three services, to clearly highlight the conditions that lead to high or low values of the framework's parameters.

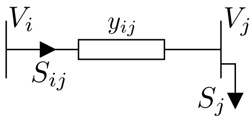

Fig. 3. Voltage phasors $V_{(\cdot)}$ at buses i and j are related to the power flow $S_{ij} = P_{ij}+\jmath Q_{ij}$ through admittance $y_{ij} = g_{ij}-\jmath b_{ij}$, with the jth node having net demand of $S_j = P_j+\jmath Q_j$.

4.1. Optimal operation of a soft open point for loss reduction

The estimation of average loss factors L_α must be based on an optimal power flow-based method, so that the change in system losses across all components of the distribution system and SOP itself can be accounted for. In this work we make use of the conic optimization formulation of [45] to formulate a suitable optimal power flow problem. This formulation is attractive as conic problems can be solved using fast off-the-shelf solvers, and because it is a convex relaxation, such that optimal solutions in the relaxed problem which are feasible in the original non-convex problem can be guaranteed to be the global optimal point. In practise, this second condition holds in many practical cases (and did so in the cases considered in this work). Furthermore, as the method is based on convex optimization, it scales well. For example, the approach has been demonstrated on networks with many hundreds of nodes [46], and so is a practical tool approach that can be used with many typical distribution network models (e.g., any of the UK generic distribution networks [47]). Note that other scalable optimization approaches can also be developed with more complex interactions with the network—e.g., a robust, convex optimization approach for scheduling both energy storage and SOPs is presented in [48].

A distribution network is modelled as having nodes $\mathcal{N}$, branches $\mathcal{B}$ and pairs of power converters $\mathcal{S}$. Fig. 3 shows two buses within a network. In [45] it is shown that

$$P_i = -\sqrt{2}u_i \sum_{ij\in\mathcal{B}(i)} g_{ij} + \sum_{ij\in\mathcal{B}(i)} \left(g_{ij}\alpha_{ij} - b_{ij}\beta_{ij}\right) , \tag{16}$$

$$Q_i = -\sqrt{2}u_i \sum_{ij\in\mathcal{B}(i)} b_{ij} + \sum_{ij\in\mathcal{B}(i)} \left(b_{ij}\alpha_{ij} + g_{ij}\beta_{ij}\right) , \tag{17}$$

$$S_i = \sum_{ij\in\mathcal{B}(i)} S_{ij} , \tag{18}$$

$$2u_iu_j = \alpha_{ij}^2 + \beta_{ij}^2 , \tag{19}$$

where $\mathcal{B}(i)$ is the set of branches connected to node i, and

$$u_i = \frac{|V_i^2|}{\sqrt{2}} , \qquad \alpha_{ij} + \jmath\beta_{ij} = \frac{V_i}{V_j}|V_j|^2 . \tag{20}$$

The losses in the ijth branch $P_{\mathrm{Loss},\,ij}$ are

$$P_{\mathrm{Loss},\,ij} = |S_{ij}|^2 g_{ij} u_i \sqrt{2} , \tag{21}$$

and the voltage limits $u^{\min}$, $u^{\max}$, and branch limits $S_{ij}^{\max}$ are enforced as

$$|S_{ij}| \leq S_{ij}^{\max} \,\forall\, ij \in \mathcal{B}, \quad u_{\min} \leq u_i \leq u_{\max} \,\forall\, i \in \mathcal{N} . \tag{22}$$

SOP losses $P_{\mathrm{Loss,\,SOP},\,i}$ are modelled as [3]

$$P_{\mathrm{Loss,\,SOP},\,i} = k_{\mathrm{SOP}} |S_{\mathrm{SOP},\,i}| , \tag{23}$$

where k_{SOP} is the SOP converter loss factor, and $S_{\mathrm{SOP},\,i}$ is the complex power injected by the converter, bounded by the power rating $S_{\mathrm{SOP},\,i}^{\max}$ as

$$|S_{\mathrm{SOP},\,i}| \leq S_{\mathrm{SOP},\,i}^{\max} . \tag{24}$$

The real power balance across converters i, j (together forming a SOP) is given by

$$P_{\mathrm{SOP},\,i} + P_{\mathrm{SOP},\,j} + P_{\mathrm{Loss,\,SOP},\,i} + P_{\mathrm{Loss,\,SOP},\,j} = 0 . \tag{25}$$

Table 2
Minimum, median and maximum annual average loss reduction L_α, in kWh/kVA-yr, as determined with the approach described in Section 4.1.1.

Network ID	Marginal loss reduction L_α, kWh/kVA-yr					
	Nominal loading			Increased loading		
	Min[a]	Med[b]	Max[c]	Min[a]	Med[b]	Max[c]
33 Bus (Baran + Wu)	3.8	128.1	356.7	67.0	315.3	653.9
Taiwan Power Co.	0.0	0.0	76.0	0.0	1.6	178.6
HV UG (UKGDS)	0.0	0.0	16.5	0.0	0.0	28.7

'Increased' loading scales the load duration curve by 140% for Taiwan Power Company and 33 Bus networks and 111% for the UKGDS HV/UG network.
[a]Calculations with SOP efficiency of 93%.
[b]Calculations with SOP efficiency of 96%.
[c]Calculations with SOP efficiency of 98%.

The total system losses, $P_{\mathrm{Loss,\,Total}}$, consists of the sum of SOP losses and network losses. The objective of the loss minimization optimization can therefore be written

$$\min\; P_{\mathrm{Loss,\,Total}} \tag{26a}$$

$$\text{s.t. } 2u_iu_j \geq \alpha_{ij}^2 + \beta_{ij}^2 , \tag{26b}$$

$$P_{\mathrm{Loss,\,Total}} = \sum_{ij\in\mathcal{B}} P_{\mathrm{Loss},\,ij} + \sum_{i\in\mathcal{S}} P_{\mathrm{Loss,\,SOP},\,i} , \tag{26c}$$

$$(16),\ (17),\ (21)\text{–}(25) , \tag{26d}$$

where we have relaxed (19) as in [45]. This can be solved efficiently as it takes the form of a convex second order cone programme—so long as the constraint (26b) is active, the solution of (26) yields the globally optimal solution. (This condition held in all simulations considered.) Note that a DNO wishing to provide congestion management can also use this procedure, as voltage and thermal constraints are accounted for in (22).

4.1.1. Estimating the average loss reduction factor

To estimate a credible range of average loss factors L_α, we consider optimal SOP operation for three networks, using an LDC from [49], and operated using the optimal formulation (26). The networks used are given in Table 2, with each networks having between 5 and 13 locations for a SOP can replace a NOP.

The minimum, median and maximum average loss factors L_α for three efficiencies and these three networks are given in Table 2. For these simulations, it has been assumed that the SOP that is installed is small (100 kVA), as the benefits of loss reduction quickly diminish when the SOP is larger than this. Lower, central and upper loss reduction capabilities of 10, 100, and 650 kWh/kVA-yr are therefore assumed. For comparison, 653 kWh/kVA-yr is equivalent to an average loss reduction of 75 W for every kVA of SOP installed.

4.2. Evaluating network unavailability and SOP utilization

The likelihood of network outages depend on the construction of the network (e.g., overhead, underground lines) whilst the severity depends on the network design standard (e.g., if the network is $N-1$ secure), and load profile. In this subsection, we estimate the lower, central and upper estimates for network unavailability U and SOP outage utilization μ_α for estimating the network reliability viability as in (9). Note that it is implicit in this section that the goal of the SOP is to reduce total loss of load subject to network constraints, a well-accepted objective for SOP operation in post-fault settings [5].

The benefits of improved reliability due to a SOP can be demonstrated by considering Fig. 4. In this network, if a fault occurs on line $\mathcal{L}_{1,1}$, then the line can then be isolated by the normally closed switches, then loads upstream of $\mathcal{L}_{1,1}$ reconnected to Feeder $\mathcal{F}_1$ and loads downstream of $\mathcal{L}_{1,1}$ would be reconnected through Feeder $\mathcal{F}_2$. Following this isolation, the SOP can then reduce the EENS by providing

Table 3
An estimate of low, central and high estimates of network unavailability considering two interconnected feeders, assuming urban networks have underground (UG) cables with 0.05 faults/km-yr and rural networks have overhead (OH) construction with 0.1 faults/km-yr. Values based on [50, Ch. 4].

Value	Description	Total length, km	Failure rate, per yr	MTTR, h	Unavailability U, h/yr
Low	Short urbanfeeder (UG)	0.5	0.05	10	0.5
Med.	Suburbanfeeder (UG)	2	0.2	10	2
High	Ruralfeeder (OH)	20	2.0	4	8

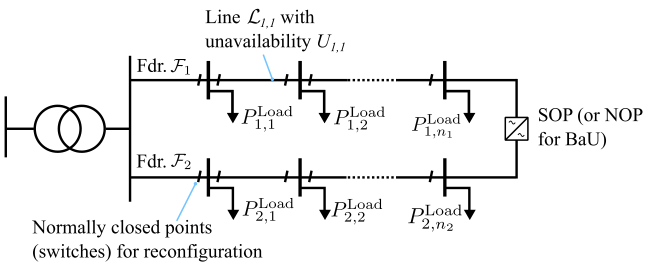

Fig. 4. A model of a network ring main used for evaluating reliability benefits of SOPs, quantified by estimating the likelihood and severity of outages. SOPs can reduce the impact of outages by responding more quickly than electromechanical switches, or by delivering capacity in post-fault conditions which cannot be provided by reconfiguration alone.

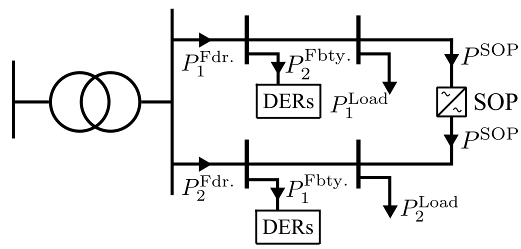

Fig. 5. A model of a ring main system, used to quantify the benefits that a SOP can provide by enabling DER flexibility in a congested distribution network. The flexibility can be used to provide a range of system services (e.g., relieving transmission congestion).

an instantaneous response to supply loads, rather than having to wait potentially more than an hour for manual reconfiguration.

The total unavailability of the two feeder system can be approximated (assuming faults do not occur concurrently) by summing all unavailabilities,

$$U = \sum_{i=1}^{2} \sum_{j=1}^{n_i} U_{i,j} \,. \tag{27}$$

We assume this unavailability U to have low, medium and high rates between 0.5 and 8 h/yr, as summarized in Table 3.

The SOP outage utilization μ_α (in kW/kVA) can then be calculated by estimating the EENS for BaU and SOP cases, then determining the utilization as

$$\mu_\alpha = \frac{\text{EENS}^{\text{BaU}} - \text{EENS}^{\text{SOP}}}{\alpha U} \,. \tag{28}$$

Lower, central and upper estimates of the utilization factor μ_α have been calculated as follows.

- The upper estimate assumes a SOP is connected between feeders for which traditional reconfiguration is not possible post-fault due to network constraints, and for which there is always a shortfall when an outage occurs which the SOP can only partially meet. The SOP is then fully utilized during the fault by definition, so the utilization rate μ_α is 1 kW/kVA.
- The central estimate assumes the SOP also allows power transfer not possible via reconfiguration, but it is assumed that after a fault there is a shortfall only part of the time (i.e., there is some spare capacity on the network). If it is assumed that peak demand is 40% greater than the capacity of the network following one outage, then the utilization of a SOP μ_α is 0.097 kW/kVA (using the LDC from [49]).
- The lower estimate of SOP utilization is when the SOP replaces a NOP for which reconfiguration would be possible (e.g., as in Fig. 4). The benefit of the SOP is then through the reduction in reconnection time. It is estimated to reduce connection time by 30 min per interruption, with average utilization of 50% during those periods (e.g., assuming a SOP sized to meet total demand on the feeder, with uniform load density and uniform outage probability along the length of the feeder). Assuming 2 faults/yr with MTTR of 10 h, the utilization rate μ_α is then 0.025 kW/kVA.

Note that the fast rate of response of a SOP, which is often discussed one of the key advantages of SOPs [3], actually leads to a much lower utilization rate during fault conditions as compared to those cases where it is used where reconfiguration is not possible. This implies that, where the societal cost of network outages is accurately described by the VoLL, the speed of the power electronics is relatively inconsequential when compared to post-fault power transfers that the SOP enables that would not be possible via reconfiguration. Some network configurations where power electronics may be useful in this context are described in [51].

4.3. Flexibility of a ring main system

To consider how SOPs can enable flexibility in a distribution network with congestion, we consider the 'ring main' style system shown in Fig. 5. The DERs in the network can change their demand $P_i^{\text{Fbty.}}$ to respond to the common flexibility signal, but must not increase the demand such that total feeder power $P_i^{\text{Fdr.}}$ is greater than the feeder power limit $P_i^{\text{Fdr., max}}$ in either feeder. The SOP shift powers P^{SOP} between feeders to maximize the DER demand turn up.

In this case, the additional flexibility that the SOP enables can be found by solving the linear program

$$\max_{P^{SOP}} \sum_{i=1}^{2} P_i^{\text{Fbty.}} \,, \tag{29a}$$

$$\text{s.t. } |P^{\text{SOP}}| \leq P^{\text{SOP, max}} \tag{29b}$$

$$P_1^{\text{Fdr.}} = P_1^{\text{Load}} + P_1^{\text{Fbty.}} + P^{\text{SOP}} \tag{29c}$$

$$P_2^{\text{Fdr.}} = P_2^{\text{Load}} + P_2^{\text{Fbty.}} - P^{\text{SOP}} \tag{29d}$$

$$|P_i^{\text{Fbty.}}| \leq P_i^{\text{Fbty., max}} \,, \quad i \in [1,2] \tag{29e}$$

$$|P_i^{\text{Fdr.}}| \leq P_i^{\text{Fdr., max}} \,, \quad i \in [1,2] \,, \tag{29f}$$

where it has been assumed that losses can be neglected. The objective of the optimization is to use the SOP to maximize the total additional demand of the ring main, given controllable additional flexibility $P_i^{\text{Fbty.}}$ and SOP controllability (29a). This is subject to constraints on the power that the SOP can transfer (29b), power balance constraints (29c), (29d), limits on the permissible flexibility for the loads in the network (29e) and thermal limits on the lines (29f).

Note that, if one of the feeders has a large capacity (e.g., $|P_2^{\text{Fdr.}}| \ll P_2^{\text{Fdr., max}}$ throughout the year), then the SOP will be more effective

Table 4
Summary of parameters used in Cost–Benefit Analysis.

Parameter	Description	Value				Reference
		Lo.	Med.	Hi.	Unit	
r	Discount rate	3.5	3.5	3.5	%	[52]
N_t	SOP lifetime	10	10	10	yrs	[53,15]
C_α	SOP marginal cost	100	160	400	\$/kVA	[37,15]
C_{Energy}	Marginal cost of energy	25	54	100	\$/MWh	Section 3.1
$C_{\text{Fbty.}}$	Mean value of flexibility	0.5	2.0	7.0	\$/MWh	Section 3.5
C_{VoLL}	Value of Lost Load	20	20	20	\$/kWh	[40]
$C_{\text{Reinf.}}$	Reinforcement costs	0.6	5	20	\$m	[54]
N_{DG}	No. years DG curtailment	3	6	10	yrs	Section 3.2
G_N	Load growth	0.1	0.4	0.8	MVA/yr	[41]
L_α	Loss reduction per unit SOP	0.01	0.1	0.8	MWh per kVA-yr	Table 2
G_α	Reduced curtailment per unit SOP	0.09	0.44	1.1	MWh per kVA-yr	Section 3.2
μ_α	SOP outage utilization	0.025	0.1	1.0	kW/kVA	Section 4.2
U	Circuit unavailability	0.5	2	20	h/yr	Table 3
ρ_α	Potential flexibility utilization p.u. SOP	0.67	1.72	5.75	MWh per kVA-yr	Section 4.3

as the power transferred will not be from a feeder which also has congestion. When this condition holds, the flexibility benefit over the year can be determined in closed form rather than by the solution of the program (29). In particular, by calculating the margin Z at each time instant j, the marginal flexibility potential ρ_α can be determined as

$$Z[j] = P_1^{\text{Fdr., max}} - P_1^{\text{Load}}[j] - P_1^{\text{Fbty., max}}, \tag{30}$$

$$\rho_\alpha = \frac{1}{\alpha}\sum_{j=1}^{8760}\left(\min\{Z[j]+\alpha, 0\} - \min\{Z[j], 0\}\right). \tag{31}$$

Lower, central and upper estimates for the potential SOP utilization ρ_α are therefore estimated as follows.

- Central and upper potential SOP utilization ρ_α are calculated assuming one of the feeders has high capacity, so that (30), (31) hold. Assuming 35% and 70% additional flexibility for central and upper flexibility capabilities $P_i^{\text{Fbty., max}}$, and assuming the feeder peak demand $P_1^{\text{Fdr.}}$ matches the feeder rating $P_1^{\text{Fdr., max}}$, then using the LDC from [49] and 0.1 pu capacity SOP yields a potential utilization ρ_α of 1.1 and 7.1 MWh/kVA-yr, respectively.
- For the lower estimate of utilization, again 35% peak power is assumed to be available for flexibility; in contrast to the central estimate, however, it is assumed that the feeder is connected to an feeder which is has identical loading characteristics but with a capacity that is increased by 10% (i.e., $P_2^{\text{Fdr., max}} = 1.1 \times P_1^{\text{Fdr., max}}$). By solving the program (29) across the year, the SOP utilization ρ_α is 0.43 MWh/kVA-yr.

5. Comparing the viability of soft open points using the CBA framework

Table 4 collects the range of credible values estimated for each of the parameters required to apply the proposed framework. In this section, these parameters are used to estimate both NPV and CP points for SOPs that enables a comparison between each of the value streams. To demonstrate the estimated values of parameters are accurate quantitatively whilst exploring the advantages and limitations of the approach, a pair of case studies are presented for the value stream of reinforcement deferral. Finally, a detailed discussion is presented to discuss the advantages and limitations of the approach, and to discuss possible future research directions.

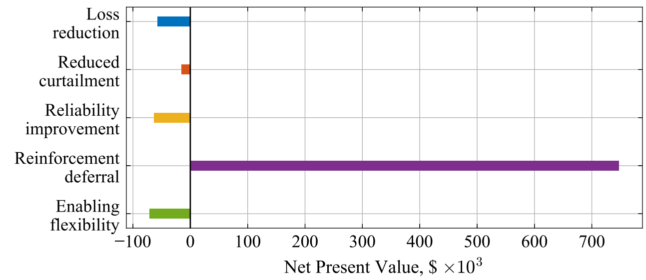

Fig. 6. The NPV of each value stream, assuming an 0.5 MVA SOP (except reinforcement deferral with a 4 MVA SOP). Reinforcement deferral is the only value stream with a positive NPV. Note that the installation of a 0.5 MVA SOP has a capital cost of \$80k.

Table 5
Parameter values that result in SOP and BaU projects having identical NPVs.

Value stream	Assumption(s)	Critical parameter value
Loss reduction	Energy cost C_{Energy} is 54 \$/MWh.	Marginal loss reduction L_α of 0.34 MWh/kVA-yr.
Reduced curtailment	Energy cost C_{Energy} is 54 \$/MWh, and 6 yrs of DG benefits N^{DG}.	Marginal curtailment reduction G_α of 0.54 MWh/kVA-yr.
Reliability improvement	VoLL C_{VoLL} of 20.0 \$/kWh and unavailability. U of 2.0 h/yr.	SOP outage util μ_α of 0.469 kW/kVA.
Reinforcement deferral	Reinforcement cost $C_{\text{Reinf.}}$ of \$5.0 m.	Annual load growth G_N of 0.867 MW/yr.
Enabling flexibility	Flexibility cost $C_{\text{Fbty.}}$ is 2 \$/MWh.	Marginal potential SOP utilization ρ_α of 9.37 MWh/kVA-yr.

5.1. Central estimates of net present value

In the first instance, to consider the viability of SOPs we calculate the NPV of each of the value streams using the central estimates of all parameters values of Table 4. In each case, the SOP is assumed to be 0.5 MVA, except for the reinforcement deferral value stream (which has a 4 MVA SOP to align with the central estimate of 0.4 MVA/yr load growth over ten years).

The results of this calculation are presented in Fig. 6. It can be seen that reinforcement deferral is the only value stream with a positive NPV. This is an interesting result as it confirms that the approach of using SOPs to provide capacity for a limited time can yield system-wide benefits.

It is worth noting, however, that the reinforcement deferral benefit may only be realizable at a relatively small number of locations. This value stream requires the distribution network to not only have a moderate or low level of load growth, but also that the substation or circuit is on the cusp of reaching its declared capacity. Furthermore, there must be a nearby network which can provide the capacity required for the duration of the project. Nevertheless, as consumers adopt increasing numbers of LCTs, this could be an important use-case for SOPs in future distribution systems.

5.1.1. Critical parameter values for a viable SOP

To explore in more detail the viability of the other value streams, the value of parameters required to yield a viable project are given in Table 5, assuming a SOP cost of \$160/kVA and a project life of ten years. As expected, a higher value of load growth than the central estimate (Table 4) is permissible for the reinforcement deferral (by (11), lower load growth leads SOPs to be more competitive).

On the other hand, the values of four critical parameters for the other applications are also higher than the central estimates. For the loss reduction, reduced curtailment, and SOP reliability cases the project becomes viable if the parameter considered is between the

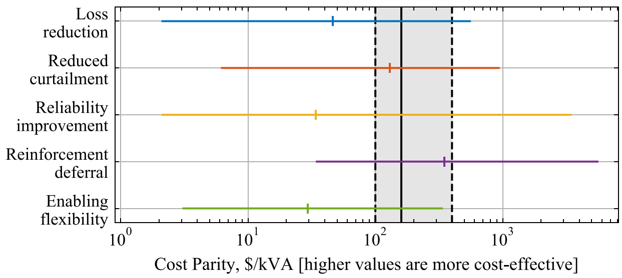

Fig. 7. The range and central estimate of cost parity (as defined in (2)) using parameter values from Table 4, with the range and central estimate of the power electronics marginal cost C_α indicated by shaded area and vertical lines. A higher CP indicates a more robust case for the SOP proposition; a CP higher than the cost of power electronics indicates a viable project.

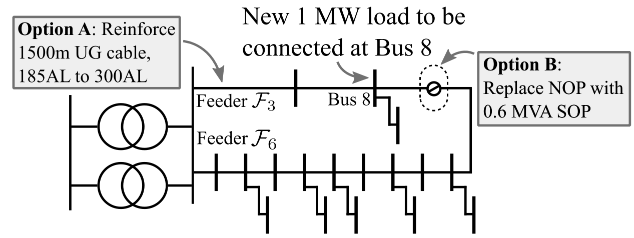

Fig. 8. Two of eight feeders of the 75 bus UKGDS HV UG network, as modelled in Case Study 1. This case study considers two approaches for meeting an additional 1 MW load at Bus 8, either reinforcing 1500 m of cable at the head of Feeder $\mathcal{F}_3$ (Option A/BaU), or the installation of a 0.6 MVA SOP in place of the NOP between the end of the two feeders $\mathcal{F}_3$, $\mathcal{F}_6$ (Option B/SOP).

central and upper estimates (from Table 4), although it is worth noting that in some cases it is many times the central estimate (e.g., for service reliability).

For enabling flexibility service, the marginal potential SOP utilization ρ_α must be 9.4 MWh/kVA-yr. This is greater than the nominal value if the SOP has 100% throughout (with value 8.76 MWh/kVA-yr), and so is considered very unlikely. This suggests that enabling flexibility is the weakest value stream.

5.2. Variability in viability of value streams

It can be seen in Table 4 that the parameters that drive SOP viability change by several orders of magnitude. As discussed in Section 2, the CP provides an alternative approach of considering the viability of a SOP, providing the marginal cost C_α for which a SOP proposition becomes viable. A value much greater than the cost of power electronics indicates a strong proposition.

The value of the CP has been calculated assuming lower, central and upper estimates of each of the parameters in Fig. 7 for all five value streams. The central tick of each value stream on this figure is calculated assuming all parameters are at their central values (from Table 4), whilst the range is plotted by calculating the cost parity assuming all values are at their upper or lower values. The shaded area covers the range of estimated marginal costs of SOPs C_α, with the solid black line indicating the central estimate of $160/kVA. Note that the values are plotted on a logarithmic scale due to the wide range of CP values.

This figure suggests that reinforcement deferral is likely to be a key use-case for the SOP where it is feasible, with reduced curtailment also providing potential opportunities as a viable proposition. For all value streams, the upper estimates of CP are cost-effective, indicating all services could have potential application in future distribution systems.

The central estimates for loss reduction, flexibility and service reliability are, however, all some way below the lower estimate of the cost of power electronics C_α. This suggests that the SOP is unlikely to have widespread use in providing those services in themselves, except for in cases where there are favourable conditions for the SOP. Furthermore, in marginal cases, where one service only just has a positive NPV, these services can be the differentiator between a viable and unviable project, as we demonstrate in the case study in Section 5.3.

5.3. Detailed case studies

When a project is viable but only has a moderately positive NPV (i.e., with a CP only slightly higher than the SOP marginal cost), is particularly important to undertake detailed analysis required to evaluate and stack the value of each service to determine the overall project NPV and therefore the SOP viability.

In this subsection, two detailed case studies are presented to demonstrate how projects which are superficially viable can have either positive or negative NPV once the full suite of value streams are considered, whilst also highlighting that the parameters presented in the previous section (Table 4) are accurate. A full year's hourly simulation is undertaken to ensure the values are calculated accounting for all operating conditions of the network.

5.3.1. Case study descriptions

The proposed case studies are based the 75 bus UKGDS HV UG urban network [55]. The network has a peak load of 24 MW, distributed between eight feeders, with distributed generators spread throughout the network (sized as 400 kVA in this work). A representative demand profile for the network has been used as provided by the local DSO (Northern Powergrid), with DGs following a solar PV profile from [56].

5.3.2. Case study 1: Non-secure ring main

The first case we consider is an HV ring main between two feeders, shown in Fig. 8. In this first case, it is assumed that the DSO is required only to maintain supply during normal operation. As a result, if there is an outage in either Feeder $\mathcal{F}_3$ or $\mathcal{F}_6$, then there will often be a shortfall in the network (e.g., if there is a network fault during the evening peak).

A total of 9.4 MW additional load is connected between these two feeders, putting them both close to the thermal limit of their underground cables. If a further 1 MW load is connected at Bus 8 then there will be a thermal overload at the head of Feeder $\mathcal{F}_3$ at peak load. The DSO is therefore obligated to identify the most cost-effective solution to increase network capacity to alleviate this congestion. The BaU reinforcement approach (Option A) would be to upgrade the 1.5 km of underground cable conductor from 185 mm aluminium (Al.) to 300 mm Al., increasing the thermal limit from 6.82 MVA to 8.86 MVA, with an estimated cost $C_{\text{Reinf.}}$ of $469k.

Alternatively, the NOP between the two feeders could be replaced with an 0.6 MVA SOP. In this case, the SOP can then be used to inject power from Feeder $\mathcal{F}_6$ to the end of Feeder $\mathcal{F}_3$ to reduce the power flowing to the head of Feeder $\mathcal{F}_3$ during peak loads. This operation is shown in Fig. 9 for three days in January, demonstrating the increase in load on Feeder $\mathcal{F}_6$ and reduction in load on Feeder $\mathcal{F}_3$ during peak load hours.

Assuming a SOP installation cost of 160 $/kVA, the installation of a SOP costs $96k, whilst deferring the reinforcement by SOP lifetime N_t of 10 years yields a benefit of $130.1k. Therefore, based on this analysis of only the reinforcement deferral value stream, the SOP is cost-effective–the NPV is $34.1k greater for the SOP case (Option B) as compared to Business-as-Usual reinforcement (Option A), with a total present value of the required investment costs of $434.8k.

However, the SOP case (Option B) performs poorly when compared to the BaU reinforcement (Option A) for flexibility and reliability improvement services (Table 6). This is because the SOP case leads

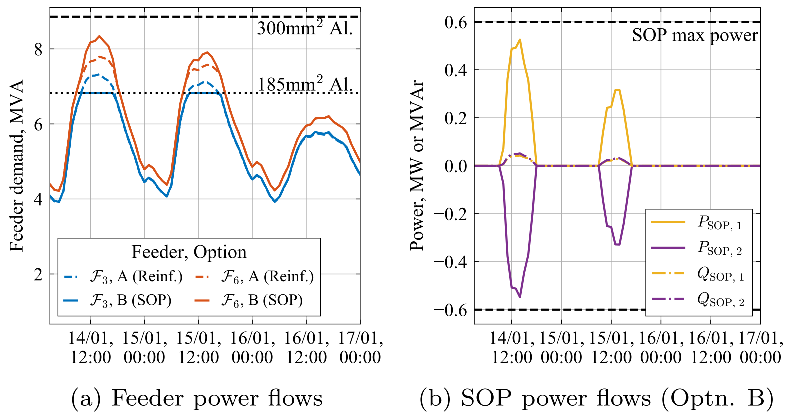

Fig. 9. Power flows (a) in the feeders $\mathcal{F}_3$, $\mathcal{F}_6$ considering either conductor reinforcement (Option A) or SOP installation (Option B); and, the power flows through the SOP (b). The conductor of Feeder $\mathcal{F}_6$ is 300 mm^2 aluminium (Al.). The conductor of Feeder $\mathcal{F}_3$ is 300 mm^2 Al. for reinforcement (Option A) or 185 mm^2 Al. in the SOP case (Option B).

Table 6
NPV and difference in NPV between Option A (Reinforcement) and Option B (SOP installation).

Value stream	NPV, \$×10^3		ΔNPV, \$×10^3
	Opt. A (Reinf.)	Opt. B (SOP)	
Loss reduction	1.9	−48.7	−50.6
Reliability improvement	70.5	−32.0	−102.5
Reinforcement deferral	0.0	34.1	34.1
Enabling flexibility	67.9	10.2	−57.8

to higher levels of congestion at the head of feeder $\mathcal{F}_3$ when the new load is added at Bus 8, resulting in additional demand without any new capacity on lines in either Feeder $\mathcal{F}_3$ or $\mathcal{F}_6$. This means that when faults occur (or flexibility is requested), the DSO has to step in to restrict power flow even more than in the base case. In contrast, reinforcing feeder $\mathcal{F}_3$ (Option A) adds more capacity to Feeder $\mathcal{F}_3$ than the increase in demand, leading to improved service (and therefore greater NPV) as compared to the base case. To calculate the reliability benefits, branches are assumed to have an emergency rating of 120% of their steady-state rating, with a failure rate of 0.05 failures/yr, and a mean time to repair of 10 h. It is assumed that the DNO can disconnect customers in a continuous way, following prior works (e.g., [5]).

Furthermore, because the SOP must transfer power between feeders during periods of high demand (and there is only a low rate of loss reduction during off-peak periods) the losses are significantly greater in the SOP case (Option B). As a result, when all value streams are combined, the NPV is instead negative, with the NPV of the \$–176k (Table 6). In other words, once the whole system value is calculated, the result is that the SOP is economically nonviable. Conversely, the reinforcement deferral SOP benefit is clearly not sufficiently great to neglect other value streams in this case study.

The significance of these value streams can be made clear by exploring the values of the parameters resulting from the analysis, given in Table 7, with the breakdown of benefits of each value stream represented visually in Fig. 10(a). It can be seen that the reinforcement cost $C_{\mathrm{Reinf.}}$ is relatively low, whilst the marginal loss reduction L_α, potential SOP flexibility utilization ρ_α and SOP outage utilization μ_α are all well above the central estimate. This explains why, when the value streams are compared, the reinforcement deferral has a relatively low impact on the overall project feasibility.

5.3.3. Case study 2: Secure ring main

The second case study is based on a ring main that is operated to an $N-1$ security standard. $N-1$ security means that, when there is an outage on a circuit, there is sufficient capacity to meet all demand without load shedding (except at the faulted section of the network).

Table 7
Net value of parameters from case 1 (non-secure) and Case 2 (secure), taken as the difference between BaU (reinforcement) and proposed (SOP) cases as appropriate.

Parameter	Value, Case 1	Value, Case 2
N_t	10 yrs	10 yrs
C_α	160 \$/kVA	160 \$/kVA
$C_{\mathrm{Reinf.}}$	\$469k	\$469k
G_N (eqvlnt.)	0.06 MW/yr	0.06 MW/yr
C_{Energy}	54.3 \$/MWh	54.3 \$/MWh
L_α	−140.0 kWh/kVA-yr	−8.7 kWh/kVA-yr
$C_{\mathrm{Fbty.}}$	2 \$/MWh	n/a
ρ_α	−5.64 MWh/kVA-yr	n/a
C_{VoLL}	20 \$/kWh	20 \$/kWh
U	4.66 h/yr	n/a
μ_α	−0.21 kWh/kVA	n/a

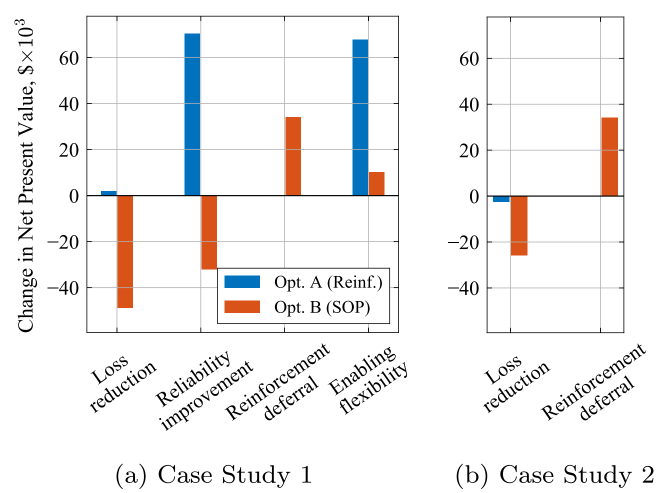

Fig. 10. Net present values for each case study for the four value streams for both Business-as-Usual reinforcement (Opt. A) and a proposed SOP project (Opt. B).

For this case, we consider the interconnection of Feeder $\mathcal{F}_3$ and $\mathcal{F}_6$ and a second ring main, connected between Feeders $\mathcal{F}_7$ and $\mathcal{F}_2$, as shown in Fig. 11. In this case, an additional 2 MW load shared between Feeders $\mathcal{F}_3$, $\mathcal{F}_6$ means that a proposed 0.8 MW load at Bus 28 cannot be connected whilst maintaining secure operation.

As in Case 1, the Business-as-Usual approach (Option C) is to reinforce the conductor at the head of Feeder $\mathcal{F}_3$, which means that both Feeder $\mathcal{F}_6$ and $\mathcal{F}_3$ have capacity to carry the total peak load of both of those feeders. This means that if there is a fault anywhere on feeder $\mathcal{F}_3$ or $\mathcal{F}_6$, the fault can be isolated, then all of the demand fed

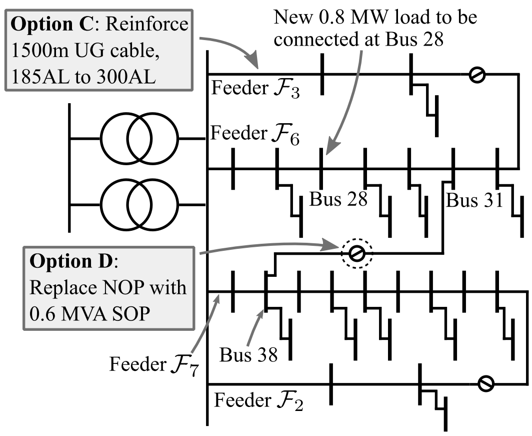

Fig. 11. Case Study 2 considers two approaches for meeting an additional 0.8 MW load at Bus 28, either reinforcing 1500 m of cable at the head of Feeder $\mathcal{F}_3$ (Option C/BaU), or the installation of an 0.6 MVA SOP in place of the NOP between feeders $\mathcal{F}_6$, $\mathcal{F}_7$ connecting Bus 31 and Bus 38 (Option D/SOP).

Table 8
NPV and difference in NPV between Option C (Reinforcement) and Option D (SOP installation).

Value stream	NPV, $\$\times10^3$		ΔNPV, $\$\times10^3$
	Opt. C (Reinf.)	Opt. D (SOP)	
Loss reduction	−2.6	−25.9	−23.4
Reinforcement deferral	0.0	34.1	34.1

by the adjacent feeder by closing the NOP that is connected between Feeders $\mathcal{F}_3$ and $\mathcal{F}_6$.

Alternatively, a SOP can be installed between Feeder $\mathcal{F}_7$ and $\mathcal{F}_6$ (Option D). In this case, when there is a fault, the NOP between $\mathcal{F}_3$ and $\mathcal{F}_6$ again closes once the fault has been isolated; the SOP is used to inject power from Feeder $\mathcal{F}_7$. This power injection reduces the power drawn from the substation into Feeder $\mathcal{F}_3$, meaning that the underground cable reinforcement required for Option C is no longer needed.

Because the network has a relatively high capacity (to meet the security standard), the value of enabling the flexibility service does not change from the BaU case (Option C) to the SOP case (Option D). Similarly, by definition, secure operation means that the EENS is zero for both cases.

There are therefore only the reinforcement deferral and loss reduction value streams in this second case study. The NPV for reinforcement deferral (equipment costs) is identical to Case Study 1, as the reinforcement and SOP equipment costs of Options C, D are the same as Options A, B. However, because the inefficient SOP power transfer does not have to occur to meet peak demand (as was necessary to address congestion in Case Study 1), the impact of the SOP on system losses is much less. As a result, the project is viable with an NPV that is greater than the reinforcement solution by \$10.7k (Table 8, represented visually in Fig. 10(b)), with parameter values in Table 7 demonstrating the average loss reduction L_α has been reduced tenfold.

5.4. Discussion

The proposed framework has advantages of simplicity and scalability. However, as highlighted in Section 4, determining the value of some values can be challenging, particularly given the wide range of distribution system topologies, equipment types, and changing consumer profiles. It is therefore both a feature and challenge with the proposed method that it does not evaluate the likelihood of conditions being realized. Nevertheless, future work could look to assess this for a more complete picture across network types–for example, if the relative fraction of networks that fit given archetypes was known (e.g., considering the breakdown of [47]), then estimates for the prevalence might also be possible to estimate rather than just viability in individual cases. Additionally, if a project is viable (i.e., has a positive NPV), then there are a number of measures that can describe how attractive a project is. For example, payback period, internal rate of return, cost–benefit ratio or even risk-aware quantities such as conditional value at risk can also be used to assess the effectiveness of a project. Nonetheless, it is worth noting that maximizing the expected NPV is the correct decision-making rule for risk-neutral entities [26, Ch. 1].

A further point that the comparative analysis approach highlights is the need to consider future uncertainty. For example, recent geopolitical events in Eastern Europe have caused natural gas prices (and therefore the cost of generating from OCGT and CCGT plants) has gone up by huge amounts–for example, the UK's gas price has increased from a historic average close to 50p/therm to more than 200p/therm in the first half of 2022 [57]. Conversely, if consumer investment in resilience measures to protect against blackouts (e.g., Vehicle-to-Home systems), the average VoLL will drop as consumers become less sensitive to short duration power outages. The construction of credible future scenarios is therefore a challenging task in itself and could be considered in future works.

It is interesting to note that the analysis suggests that the speed of the SOP is not as important as other parameters in the CBA, as noted previously in Section 4.2. For example, it is noted in [9] that SOPs can operate within milliseconds, where electromechanical NOPs typically operate within hundreds of milliseconds, and therefore operate in the timeframes associated with network protection. In other words, without a clear system need for responsive elements within those timeframes, the speed benefits of SOPs are unlikely to provide a significant service beyond remote control switching efforts (which would be needed prior to a SOP installation in any instance). Future efforts could therefore consider solutions more suited to power quality applications as the BaU, such as uninterruptible power supplies (UPSs).

Finally, although this framework has been proposed for the analysis of the SOP, there are other smart technologies for which the proposed framework could be applicable. In particular, the framework is best suited when a proposed solution can support a range of possible services and when these solutions would naturally be wholly owned by the DSO. For example, solid state transformers or MVDC lines can also provide a range of network services. Future work could consider applying the proposed comparative framework to other such new network technologies.

6. Conclusion

Determining the most promising services for new, smart technologies such as Soft Open Points is complex, requiring assessment of a range of parameters that are influenced by SOP behaviour in both normal operation and under emergency post-fault conditions. The proposed framework enables the comparison of the viability of these services, underpinned by the powerful Cost–Benefit Analysis methodology used in a novel setting. The modelling of each service via a small number of CBA parameters enables a transparent and manageable comparison between services. Methods of evaluating all of these parameters have been presented, enabling a comprehensive comparison of five candidate SOP value streams in terms of both Net Present Value and Cost Parity values.

Results suggests that reinforcement deferral has potential to be a key use-case of the SOP, with a viable project requiring moderate deferred reinforcement investment with low or moderate demand growth. The other four value streams of loss reduction, curtailment avoidance and flexibility enhancement all show that feasible projects are possible; however, of those, only the central estimate of DG curtailment leads to a potentially neutral NPV as compared to business-as-usual. In particular, it has been shown that benefits provided by enabling flexibility services or due to the speed of SOPs as compared to electromechanical NOPs are unlikely to prove cost-effective, except in exceptional circumstances.

Decision makers and DSOs and will need to evaluate not only the cost-effectiveness of Soft Open Points, but a range of new and innovative technologies in the next decade. Economically unviable solutions will never be taken up at scale, and so economic analysis cannot and should not be neglected by researchers. It is concluded that the proposed comparative framework highlights an ongoing need for rigorous CBAs to identify and match promising innovative grid solutions to achieve the necessary acceleration required to achieve a Net Zero power system in the next decade.

CRediT authorship contribution statement

Matthew Deakin: Conceptualization, Methodology, Investigation, Data curation, Funding acquisition, Writing – original draft. **Ilias Sarantakos:** Methodology, Writing – review & editing. **David Greenwood:** Methodology, Writing – review & editing. **Janusz Bialek:** Conceptualization, Methodology, Funding acquisition, Supervision, Writing – review & editing. **Phil C. Taylor:** Conceptualization, Methodology, Funding acquisition, Supervision, Writing – review & editing. **Sara Walker:** Funding acquisition, Supervision, Writing – review & editing.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Phil C Taylor reports a relationship with Northern Powergrid that includes: board membership.

Data availability

Data will be made available on request.

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Appendix

Our goal is to demonstrate the relations (13). The latter can be determined by considering the Taylor expansion,

$$\frac{1}{(1+r)^{N_t}} = 1 + N_t r + \frac{N_t(N_t-1)}{2!} r^2 + \cdots\,, \tag{32}$$

$$\approx 1 + N_t r\,, \tag{33}$$

where it has been assumed $rN_t \ll 1$. Substitution into (12) yields the second relation of (13).

Differentiating (12) and collecting terms yields

$$\frac{\partial \mathrm{CP}_{\mathrm{Dfrl.}}}{\partial N_t} = \frac{C_{\mathrm{Reinf.}}}{G_N N_t^2}\left(\frac{1 + N_t \log_e(1+r)}{(1+r)^{N_t}} - 1\right). \tag{34}$$

Again using Taylor's expansion yields the first relation as

$$\frac{\partial \mathrm{CP}_{\mathrm{Dfrl.}}}{\partial N_t} \approx \frac{C_{\mathrm{Reinf.}}}{G_N N_t^2}\left(\frac{1 + N_t r - \frac{1}{2}N_t r^2}{1 + N_t r + \frac{1}{2}N_t(N_t-1)r^2} - 1\right) \tag{35}$$

$$= \frac{C_{\mathrm{Reinf.}}}{G_N}\frac{-r^2}{1 + N_t r + \frac{1}{2}N_t(N_t-1)r^2} \tag{36}$$

$$\approx \frac{-r^2 C_{\mathrm{Reinf.}}}{G_N}. \tag{37}$$

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