2.9 Technoeconomic modelling of Non - Network Solutions

Milestone Report 1: 31/08/2024

Report for C4NET

C4NET

Project Consortium

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Acknowledgement

- This research is part of a program of fourteen projects, which have variously been funded and supported under C4NET's Enhanced System Planning collaborative research project. While conducted independently, the authors acknowledge the funding and in-kind support of C4NET, its members and supporters, and its ESP project partners.

Executive Summary

This report corresponds to “Milestone 1: Literature review on flexible network and DER technologies” of Work Package 2.9, focused on techno-economic modelling and impact assessment for valuing non-network solutions and future network investments in the context of electrification. It provides an overview of the benefits, methodologies, and applications of integrating flexibility from distributed energy resources (DERs) into distribution system planning (DSP), compared to network asset investments, within the context of the energy transition.

Key aspects of this report include:

1. **Energy transition and distribution systems**: A contextualization of the current uptake levels of DER in Australia and its challenges on the operation and planning of the distribution systems.
2. **Distribution system planning with DER**: A review on different studies that have included DER in the planning of distribution systems and the benefits coming from the flexibility, highlighting key aspects to be in the methodology such as uncertainty, physical and economic risk analysis.
3. **Methodological approaches**: The study highlights the development of modelling frameworks to find a value of DER in network planning. It explores the techniques explored in the literature to assess the value and benefits of flexibility to the grid, with considerations of the fundamental aspects that needs to be considered.
4. **Real-world frameworks for flexibility in planning**: A review in the different frameworks to incorporate DER in the distribution planning in UK, California and Australia, summarising what is the methodology applied to value DER as an option against network reinforcement.

Conclusions about DER flexibility integration in network planning

Based on the literature review, there is value in incorporating the flexibility of DERs in DSP, as these technologies, under coordination schemes, allow their operation to be adapted in order to reduce operational and investments costs. In this regard, findings from the literature on the definition of a methodology to evaluate DER flexibility in planning—key aspects such as network location, the incorporation of uncertainty, and, based on this, economic and physical risk analysis—must be considered to fully assess DERs as an alternative to network reinforcements. Furthermore, the approaches adopted in both the literature and ‘real-world’ applications often fail to integrate all the complexities that need to be analysed to establish a pricing scheme that allows DERs to become a viable option for distribution system operators (DSOs). For this reason, this project aims to develop a methodology that can incorporate the before mentioned aspects and assist DSOs and regulators in evaluating the integration of DERs into network planning.

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1. Project Overview

Background

During the last decade a massive uptake of distributed energy resources (DER) has been seen in Australia with the adoption of solar photovoltaic system and batteries [1], and the electrification of different sectors of energy consumption such as transport with electric vehicles [2] and heating with heat pump and hot water systems [3]. Furthermore, the expected uptake of these technologies is expected to continue growing in the following decades according to AEMO's forecast of DER capacity installed by 2050 [4] as is shown in Figure 1:

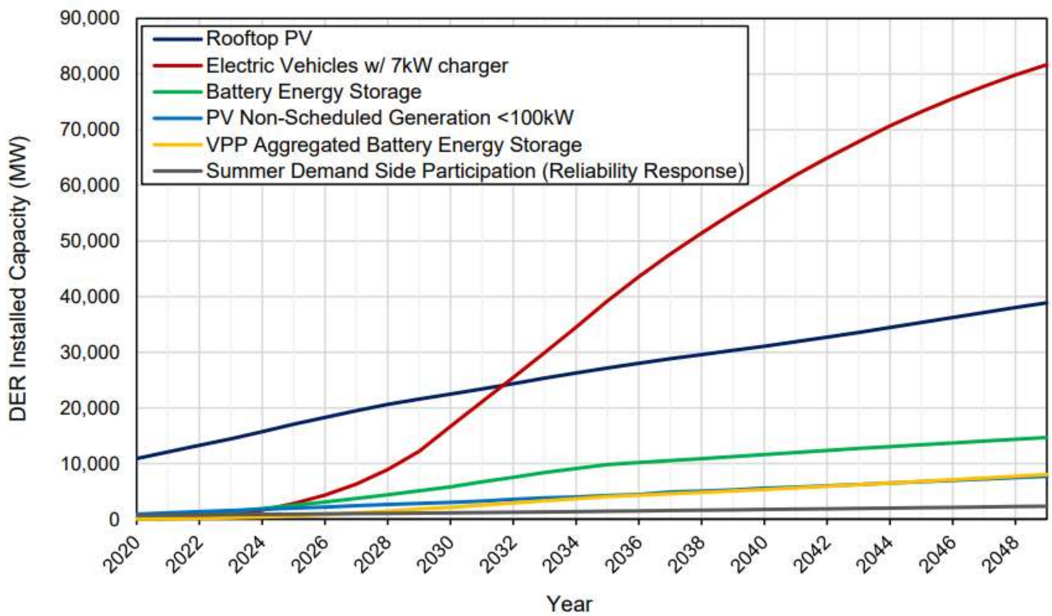


Figure 1: Average of AEMO Scenarios for DER installed capacity forecast [4]

The adoption of these technologies represents a paradigm shift, where end users are no longer just consumers of energy but also actively participate in the generation, and storage of electricity. Although this transition brings environmental and economic benefits for consumers, it also presents challenges in the operation and planning of power distribution systems.

Operationally, the massive uptake of non-controllable DER in distribution systems can lead to technical issues such as upstream congestion and overvoltage during periods of maximum non-dispatchable renewable generation[5], as well as undervoltage and downstream congestion during peak demand periods due to EV charging demand [6]. Moreover, the operation of these technologies is also of uncertain nature, since the behaviour of battery systems or EVs will be closely linked to the daily preferences of users, and the renewable generation will depend on meteorological factors such as solar radiation and wind.

Additionally, in the long term the levels of adoption of this technologies also introduces uncertainties in the planning of the system, given that the investments are scheduled into a regulatory process typically of 5 years, while the adoption levels of DER may change rapidly [1], [7]. Driven by these technical challenges, the DSP must ensure that the network capacity is able to cope with the increasing and uncertain adoption of DERs and the technical challenges that they may produce [8].

Traditionally, network planning involved the approach generally known as "fit-and-forget", carried out in a deterministic way, based on the worst scenario envisaged by the planning technician regarding the peak demand growth, however, due to both adoption levels and operation uncertainties, this approach may lead to overinvesting, resulting in loss of capital efficiency [9].

Although non-controllable DER introduce problems in the operation and planning of the distribution system, controllable DER and demand side response-generally non-network solutions- arise as an option to provide network support to DSOs, accommodating these resources to reduce peak demand, thus emerging as an option to defer investments in network assets [10].

However, for these solutions to be a viable investment alternative for network operators, their value must be assessed in comparison to traditional network reinforcement, considering the economic benefits that they can provide, the capacity of these solutions to defer investment and the risks associated with the planning decisions. In this regard, the primary objective of this project is to develop a methodology to evaluate the technical-economic impact of flexibility on network benefits and risk mitigation in distribution network planning.

Objectives

WP2.9 “Techno-economic modelling and impact assessment and planning methodologies to value non-network solutions, future network investment and associated risk in the context of electrification”, as part of C4NET Enhanced Systems Planning (ESP), aims to:

- Assess the benefits of future intelligence in networks, home energy management systems, and DER flexibility in general, in reducing network investment costs and risks.
- Development of a methodology for risk-aware network planning approach considering the benefits coming from flexible options.
- Assess the value of flexible network and DER technologies in planning, with considerations for planning uncertainty and of risk of stranded asset.

Milestones

The milestones established for the WP 2.9 project are shown in **Error! Reference source not found.**:

Table 1: Milestones Work Package 2.9

Milestone Number	Description	Timelines
Milestone 1	Literature Review	September 2024
Milestone 2	Methodological approaches for an enhanced techno-economic planning framework	December 2024
Milestone 3	Benefit assessment from flexible solutions based on electrification in providing network investment risk mitigation across different network areas and for different scenarios	January 2024
Milestone 4	Final Report with summary of input data and assumptions book	March 2024

2. Literature Review

a. DER as flexibility option in DSP

The integration of non-controllable DERs into the distribution system can cause technical problems in the network that may lead to reinforcement of the network. However, the implementation of coordination schemes to increase control over DER allowing DSOs to eventually operate them to reduce operational costs and defer network reinforcements. This flexibility can come from different participants of the distribution network, such as flexible loads, generators, storage systems or the use of flexible assets of the network. These schemes can be categorized as: Active Power Generation Curtailment (APGC), Energy Storage Systems (ESS), Demand Response (DR) and Active Network Management (ANM).

APGC systems grant the DSO control over the inverters of PV systems to curtail/adjust the active power output of distributed generators to reduce congestion and over voltages produced by solar energy in high radiation hours [11].

On the other hand, ESS can provide flexibility to the grid to solve technical problems due to their ability to charge and discharge energy according to the network needs. While the concept of ESS is broad, applications on the consumer side of the grid primarily focus on three areas: Battery Energy Storage Systems (BESS), Heating Storage (HESS), and Electric Vehicles (EVs).

BESS consists of static chemical storage systems that allow withdrawing and injecting power from the network, which can be used to effectively reduce peak of demand through charging in hours of high renewable energy to then inject in hours of high demand. These systems have been widely studied with the aim of reducing congestion and as an alternative to defer network reinforcements [12]. Moreover, HESS such as electric boilers and hot water systems, allow for the utilization of thermal energy stored in buildings or houses to withdraw energy during periods of low power consumption and then release it as heat during peak power demand hours reducing building consumption of energy and therefore the peak in the electrical system [13].

Following a similar principle, plug-in electric vehicles (EVs) has been studied in the literature under two operational modes to provide flexibility: unidirectional (usually called ‘smart charging’) or bidirectional (usually called ‘Vehicle-to-grid’ (V2G)). In the smart charging scheme EVs are incentivized, usually studied through price signals, to accommodate their charge schedule to answer to the needs of the system [14].Similarly, V2G systems use bidirectional chargers to use the energy stored in EVs. Thus, EVs demand can be accommodated to not only to consume energy in low demand hours but also to provide support to the network grid in congested hours [15]. One of the benefits of this technology include is that PEV generally have higher discharge power, allowing them to operate over power variations in shorter timeframes than other storage systems [16].

These last two systems (V2G and HESS), while capable of storing energy, are also considered demand response (DR) schemes, as users adjust their energy consumption to provide technical benefits to the electric grid. However, the concept of demand response is broader, encompassing any incentive that motivates end-users to shift their loads to reduce peak demand [17].

Finally, Active Network Management (ANM) schemes enhance network control by utilizing flexible assets to relieve constraints. Among different options for voltage regulation, devices such as on-load tap changers (OLTC) transformers and reactive power compensation systems are employed [18]. Moreover, to solve network congestions utilizing network reconfiguration using normal open points (NOPs) that connect two adjacent feeders that are normally open, allowing power flow and alleviating current overloads[19].

Since these flexibility options allow resources to be accommodated in the grid to alleviate technical issues, various studies have incorporated the modelling of these resources into distribution system planning. In general, by using flexible resources, network infrastructure investments are avoided, resulting in a reduction of total planning costs, which underscores the value of considering these alternatives. Although different studies reach this conclusion, each follows different assumptions, approaches, and methodologies, meaning the results obtained are closely dependent on them.

The planning approaches can be widely divided into: Deterministic, Stochastic, and Robust approaches. *Deterministic* approaches assume completely knowledge of all the variables (demand, generation, etc) and do not account for risk and uncertainties. However, it is simpler to implement and is suitable for some scenarios where uncertainties can be ignored. *Stochastic* approach considers uncertainties and incorporates them into the model using probability distributions. Involves a set of scenarios representing possible outcomes of uncertain parameters. *Robust* approaches also consider a set of scenarios, but it focuses on the worst-case analysis, offering a more conservative approach specially when the true distribution of uncertainties is difficult to specify. Moreover, the perspective of the DSO can be divided into 2 approaches: DSO perspective, where the DSO seeks to minimize the total cost without considering DER cost or profits, and DSO central planner where the DSO maximizes social welfare (or equivalently minimize total cost considering all actors in the distribution system).

The Table 2**Error! Reference source not found.** shows different papers that have developed the planning of distribution networks including DER flexibility:

Table 2: Distribution planning problems considering flexibility options

Reference paper	ESS	DR	ANM	Approach	Optimisation Perspective	DER Participates in Energy Markets	Source of uncertainty	Planning cost reduction compared with reinforcement [%]
[12]	X			Stochastic	DSO		BESS investment costs	35%
[20]	X		X	Robust	Central Planner	X	Solar generation	17%
[21]	X			Deterministic	DSO			28%
[22]	X			Stochastic	Central Planner		Net load	75%
[23]	X			Stochastic	DSO		Load growth	50%
[24]	X			Stochastic	Central Planner	X	Load/Energy prices	18%
[25]	x			Deterministic	DSO	X		1%
[26]	Generic DER			Deterministic	DSO			36%
[27]	Generic DER			Deterministic	DSO			69%
[28]	x			Deterministic	Central Planner	X		18%
[29]	x			Stochastic	Central Planner		Load growth	16%
[30]	X		X	Stochastic	Central Planner	X	Solar generation	25%
[31]		X	X	Stochastic	DSO		Load growth	45%
[32]			X	Stochastic	DSO		Load growth	34%
[33]			X	Stochastic	DSO		DR consumer participation	36%
[25]			X	Stochastic	DSO		EV-users behaviour	30%
[34]	x	x	X	Stochastic	Central Planner		Solar generation and load	26%

Different planning studies have found that DER can provide benefits in the DSP due to their capacity to provide operational flexibility to reduce network reinforcements, therefore unlocking economic value. However, these studies consider different assumptions and approaches so that different results are obtained as it can be seen in the percentage of cost reductions in the **Error! Reference source not found.**. Therefore, is important to find a methodology that considers relevant and realistic aspects in the context of DSOs to capture the benefits and the value that DERs can provide to the network as an alternative against network reinforcement.

b. Uncertainty and Risk in DSP

The integration of distributed resources introduces uncertainties in the operation and planning of distribution systems, which subsequently create risks in the decision-making process because network investments must be planned with years in advance, while the network capacity requirements will depend on the levels of DER adoption and orchestration of these resources. On the one hand, DSO must face economic risks, primarily related to investment in underutilized network assets—also referred to as 'stranded assets'—thus over-investing in network capacity augmentation that is only needed for a few hours during the year, which leads to economic inefficiencies. On the other hand, DSO faces physical risk of underinvesting in network capacity, leading to problems of reliability in the network if the demand exceeds the expected growth.

Although the uptake of DER may increment the uncertainty and therefore the risk related to the planning of the network, adopting strategies and technologies that enhance DER controllability can provide a viable approach to mitigate economic risks. To this end, several studies have incorporated methods to represent scenario-based uncertainty in network planning, evaluating this risk using metrics such as expected net present costs (NPC) [33], least-worst-regret [18], Conditional Value at Risk (CvaR) [35],etc. Results show that under this analysis, flexibility options become a more cost-effective option than network investments due to their capacity to adapt their operation to different realizations of peak demand growth, unlike traditional network reinforcements, therefore DSOs can opt for 'wait-and-see' until the realization of uncertainty to finally invest in network assets, concluding that flexibility options have more value when uncertainty is considered [31].

Despite reducing economical risks, regarding the physical risk before mentioned, the option of underinvesting in network assets giving preference to DER solutions may increase the physical risk, mainly because the power availability of this resources depends on weather conditions, market participation of DER, etc. Therefore, the reliability of these resources is generally lower than network assets [36] so that is important to analyse the capability of them to substitute distribution network capacity and hence contribute to delivery of network security. In that way, in the literature physical risk metrics such as expected excess load has been considered to analyse the performance of DER as an option against traditional reinforcement [32]. Alternatively, reliability indexes (SAIDI/SAIFI [20] or LOEE [21]) have been incorporated in the planning optimisation problem as constraints to ensure that the portfolio of network expansion is able to cope with certain performance level. Other approaches have adopted a N-1 iterative approach over the DER availability [37] in order to measure the cost incurred by the DSO if sequentially a flexibility provider is not able to operate when is needed.

It is important to highlight that when relying on DER flexibility, a trade-off exists between cost savings and reliability compared with investing in network reinforcement, since opting for flexibility options reduce cost and mitigate economic risk, but it may increase the physical risk. Therefore, a methodology to accurately assess the capability of DER as an option against network reinforcement must give a quantitative basis to both economic and physical risk, enabling a decision-makers to decide between different strategies.

Flexibility policies and applications world-wide

In the global context, different countries have developed policies and frameworks aimed at incorporating flexibility into the planning of distribution systems as an alternative option against network reinforcement.

c. UK

The current regulatory framework of distribution systems (RIIO-ED2) a policy of 'flexibility first' has been developed to encourage DSOs to evaluate DER flexibility as an option before investing in network reinforcement [38]. In that way, a framework based on flexibility tenders has been evolved to arrange flexibility contracts with DERs. Figure 2 shows the 4 types of contracts in flexibility tenders considered in UK regulation [39]:

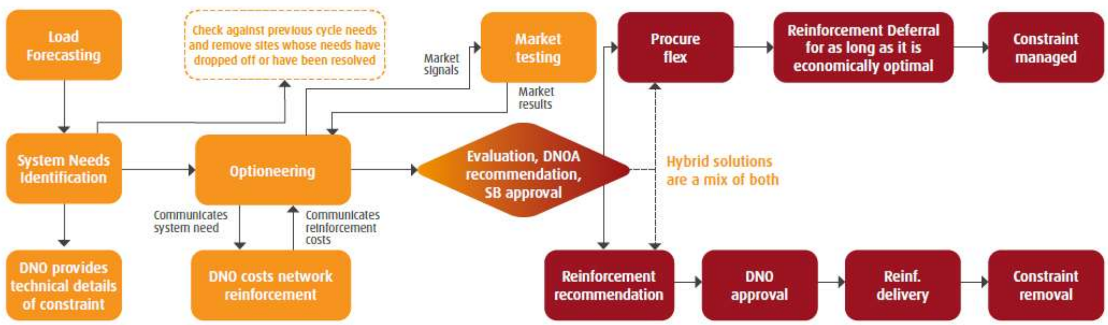
Figure 2: Flexibility Tenders Services

Market	Product name used in contract	ENA product name	Description
Long-term tender	Secure	Scheduled Availability + Operational Utilisation (SAOU)	Awarded through a long-term tender where the Provider commits to be available during contracted windows, with utilisation confirmed at Day-Ahead.
	Sustain	Peak Reduction (PR)	Awarded through a long-term tender where the Provider reduces their highest demand peaks during contracted windows.
Day-Ahead tender	Dynamic	Scheduled Utilisation (SU)	Awarded through a Day-Ahead tender where the Provider agrees to deliver their flexibility for the following day.
Outage tenders	Outage Flex	Scheduled Availability + Operational Utilisation (SAOU), Peak Reduction (PR), Scheduled Utilisation (SU), Operational Utilisation (OU), Variable Availability + Operational Utilisation (VAOU)	Awarded through irregular tenders where the Provider agrees to deliver their flexibility in line with the specific needs of a network outage. Due to variations in need, the product used can vary.

Every flexibility product is designed to provide flexibility under different objectives. In *sustain*, *secure* and *dynamic contracts* the DSO seeks to defer network reinforcement, therefore it assures capacity reservation from the flexibility provider. The objective of "Sustain" Flexibility Product is to reduce highest forecasted demand peaks, while Dynamic and Secure are designed for planned outages and demand-driven congestion, respectively. On the other hand, *Outage Flex* is designed to unplanned outages, therefore DSO does not buy capacity reservation.

In order to assess whether flexibility options can defer network reinforcement, DSOs perform a Distribution Network Options Assessment (DNOA) methodology to determine when and where a reinforcement is needed, the capacity of flexibility options to defer reinforcement and the budget to flexibility tender which represents the maximum value that can be paid to providers based on cost reductions by deferring investments in network assets [40]. Figure 3 shows the flowchart of this methodology:

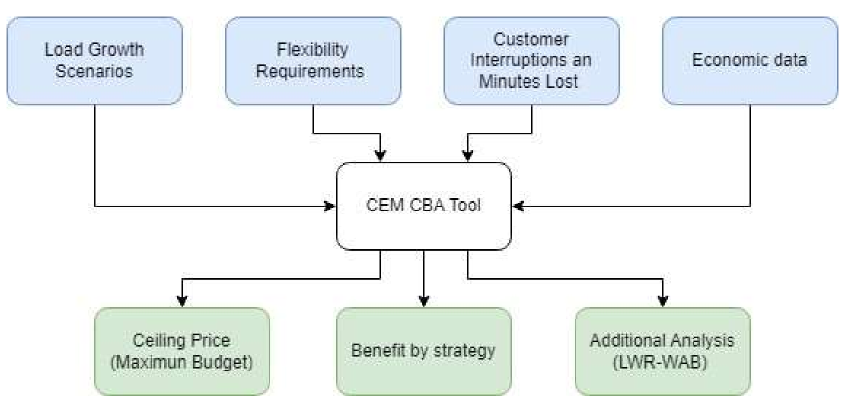
Figure 3: DNOA Methodology



This methodology firstly begins with load growth forecasting and the selection of 'best-view' scenario regarding levels of adoption of electrification and decarbonisation. Then, in 'Optioneering' step the system capacity exceedance per year is identified and along with that the planning cost analysis is undertaken according to the load forecast and considering the cost of a reinforcement project. In this, fixing a deferral time target, the cost reductions using flexibility instead of network assets are calculated to finally obtained the maximum budget of DSO to participate in the market for a specific area. Finally, if market price is economically efficient to DSOs the flexibility contract is signed, otherwise DSOs perform hybrid solutions or directly network reinforcement.

To drive DSOs in the 'Optioneering' step, Energy Network Association (ENA) published a methodology-Common Evaluation Methodology (CEM) Cost Benefit Analysis (CBA tool)- to estimate the budget for flexibility services. In this manner, the CEM not only allows DSO to enter as input a 'best-view' scenarios but also results considering scenario-based approaches such as Least Worst Regret (LWR) and Weighted Average Benefit (WAB) Analysis, allowing the network operators to value the flexibility in view of economic risk [41]. However, DSOs usually rely on a 'best-view' scenario, taking a deterministic perspective[40]. In Figure 4 the inputs and outputs of the developed tool are shown:

Figure 4: CEM CBA tool



In this manner, DSOs use as inputs the load growth scenarios, the flexibility requirements (MWh/year, number of days, hours per day and type of flexibility service), performance standards (Customer Interruptions and Minutes Lost) and economic data such as discount rate, deferral time target and traditional reinforcement plan costs. Then, the tool calculates the benefits, the maximum budget and additionally-if multiple scenarios are included- an analysis over scenarios.

This methodology has been followed by DSOs across UK to value and adopt flexibility against network reinforcement. Following this, UK's DSO SP Energy has tendered around 1500 [MW] to defer between 36 and 145 m£ in RIIO-ED2 process [42].

Even though the utilization of this tool has been useful in providing a budget gap to flexibility contracts to DSOs, since the tool does not include a DER modelling and network modelling, instead it uses technical data provided from the DSOs as inputs from previous steps in DNOA methodology to develop economic to estimate the budget to flexibility contracts.

d. California

In 2018 the California Public Utilities Commission (CPUC) established an initiative to encourage DSOs to consider DER in the existing planning process as an alternative option to defer network reinforcement, particularly through the creation of the Distribution Investment Deferral Framework [43]. This framework obligates to the DNOs to develop two analysis and reporting at the end of each year in parallel to traditional planning analysis: Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR). Considering a planning horizon of 5 years, the GNA identifies the expected issues under 4 categories of services that DERs can provide according to CPUC: Distribution Capacity, Voltage Support, Reliability (back-tie) and Resiliency (Micro-grid) [44].

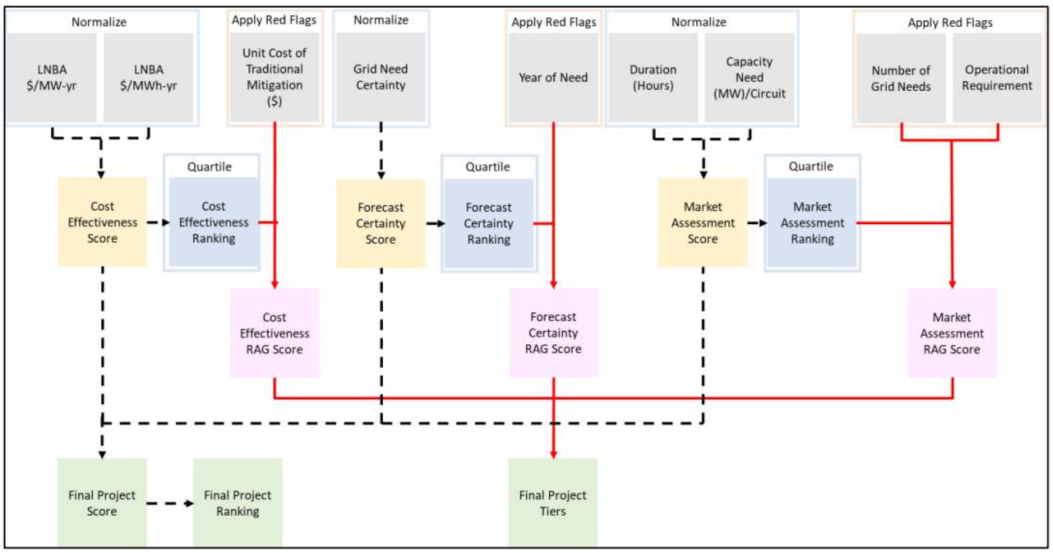
The utility then informs the identification of candidate deferral projects in DDOR, including the potential of non-wires alternatives that are prioritized into 3 tiers indicating ones that are more likely to be deferrable: Cost-Effective Metrics, Market Assessment Metrics and Forecasted Certainty Metrics [45].

Cost-Effective Metrics are divided into 3: unit cost of traditional mitigation (UCTM) [$], LNBA [$/MW-yr] and LNBA [$/MWh-yr]. UCTM is used as a red flag to disregard projects that cost less than 1[MUSD]. The LNBA-related metrics are developed by taking the deferral value for the project and dividing that value by peak capacity needs [MW] associated with project during the deferral period and the maximum annual energy required in a peak day [MWh-yr]. In that manner, projects with higher LNBA are prioritized.

Market Assessment metrics are intended to give a relative indication of how likely DER resources can be sourced to successfully meet the DER distribution service requirements. Thus, projects with high probability of service during a peak day [hours] and low-capacity needs [MW/circuit] are prioritized. The methodology applies a red flag to candidate projects with more than 3 grid needs and with forecasted failures with less than 5 minutes of operational dispatch requirement, since it is considered that the capacity of DER to solve multiple grids needs and respond in shorter timeframes than 5 minutes dispatch is not feasible.

Finally, Forecasted Certainty Metrics are intended to prioritize projects that have a high certainty of network need. In this sense, projects with high certainty are prioritized and projects that have a year of need beyond 3 years are disregarded. In Figure 5 the methodology to choose deferral projects is shown:

Figure 5: Deferral Projects Selection Process



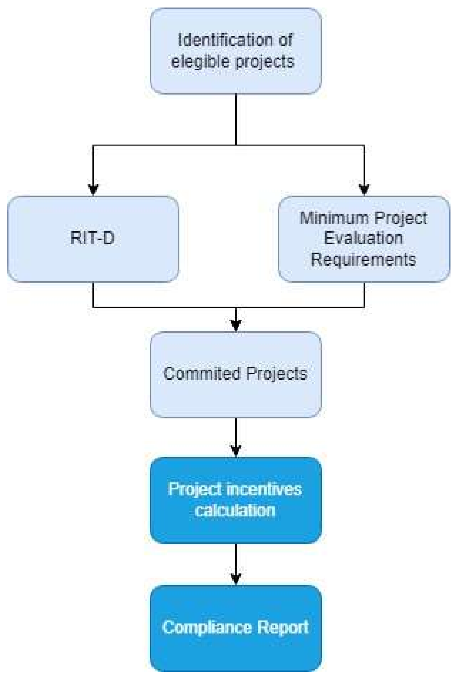
The value to grid of DER is calculated with the LNBA tool (Locational Net Benefit Analysis) based on economic data such as deferral timeframe, net present value of all the annual deferral values during the deferral timeframe considering capital cost (considering revenue requirements), operation and maintenance costs associated with the new equipment that would have been added if the traditional project had been built. Additionally, technical input data is entered such as DER profile, load profile, overloading hours, and threshold magnitude. Then, the LNBA is calculated considering the identified peak capacity [MW] and maximum annual energy per peak day [MWh-y] that is required from DER to avoid investing in network reinforcement.

This methodology has been successful in deferring investments in network reinforcements in California and evaluating the value that DERs add as an option in distribution network planning. However, this methodology is based on a deterministic approach regarding demand and generation growth in the network throughout the years. Moreover, the methodology has been focused in reducing uncertainty to select projects with high certainty of forecasted network need instead of moving towards scenario-based analysis [31].

e. Australia

The incorporation of flexibility in distribution system planning in Australia has been under the AER's demand management incentive scheme (DMIS) that gives to DNOs a financial incentive to develop non-network solutions that are able to defer, reduce or postpone network investments [46]. In that sense, the process to determine whether a project is suitable for deferring network reinforcement is presented in Figure 6:

Figure 6: DMIS process



The DMIS process starts identifying zones of the network that may need to be reinforced and possibles non-network solutions that are able to solve the network violations. In that manner, distributors must describe the identified need either through regulatory investment test of distribution (RIT-D) or minimum project evaluation requirements, detailing technical information of the identified network need such as load at risk, energy at risk, probability and frequency of relevant events, sensitivity analysis for demand scenarios (in the case of RIT-D), etc.

During the identification process, distributors issue a request for demand management solutions to potential providers that have the capability to address the identified need. In this proposal, non-network solutions providers must provide information about size and capacity (MW/MWh), type of technology, availability and reliability, then DSOs provide a maximum annual applicable payment for deferring a network investment. Finally, an economic analysis is assessed to determine whether the non-network solutions offer a more cost-effective solution than the network options through Net Present Value (NPV) analysis.

The identification process is completed when a distributor enters to a demand management contract (DMC) or a demand management proposal (DMP). DMC is a contract between distributor and another legal entity to provide flexibility while DMP is a proposal in which the demand can be managed at distributor's influence and that sets out the expected cost for managing network demand. Finally, the project incentives are calculated as follows [47]:

$$PV\ incentive_i \leq max\ \{0.5 \times E\ [PV\ DMcost_i - S_i]\ ,0\}$$

$$0.5 \times E[PV\ DMcost_i]\ \leq\ E[PV_i]$$

Where $PV\ incentive_i, E[PV\ \mathrm{DM\ cost}_i], S_i, E[NPV_i]$ are the present value of the incentive of the project *i*, expected demand management cost of project *i*, subsidies of the project *i* and expected relevant benefits of the project *i* (e.g. cost reduction from using non-network solutions), respectively.

After these steps, distributors must send a yearly compliance report of eligible (following steps described before) and committed projects, notifying the volume of demand management and the economic benefits delivered throughout the year considering payments costs. Then, incentives are assigned to distributors, where the total financial incentive must not exceed the 1% of the total annual revenue for the regulatory year.

From a regulatory standpoint, it can be inferred that AER proposes a techno-economic methodology to select projects that utilize network flexibility to defer investments in network assets. However, the regulation does not include a methodology to assess the value of contracts or proposals stipulated in the procedure for executing a non-network solutions project. Instead, the regulation allows distributors to establish contracts with flexibility providers at a certain value, if the previously mentioned constraints are met.

Methodologies to value DER in planning

Regarding the objective of assessing the benefits that flexible options offer to the grid, various approaches have been explored in the literature. These can broadly be divided into two categories: those that incorporate flexibility technologies as a decision variable (option based) in a planning problem and those that use an approach based on marginal capacity costs.

f. Option-Based Methodology

The first approach consists of a comparison between two planning problems, one considering only network assets as investment options and a second problem where the DSO can install a network asset or either pay for flexibility or install a DER, both assuming a certain fixed cost of operation and investment beforehand. Then, the benefits are calculated as the expected cost reduction between the two cases, and sensibility analysis can be conducted to analyse the value aggregated by each type of DER [31]. In these frameworks, usually is assumed that if DSO decides to implement a flexibility option, this option can be fully controlled by the DSO throughout the planning horizon for a fixed deferral period.

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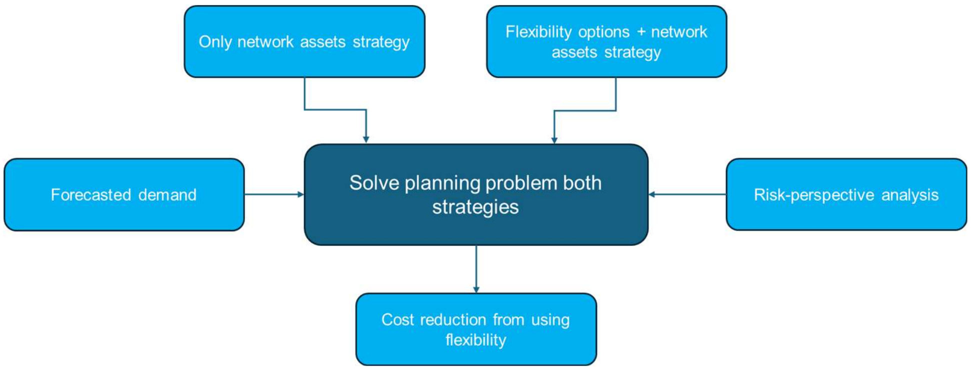
Figure 7: Option-Based Methodology



Regarding risk analysis, several studies have incorporated risk metrics or risk perspectives in the optimization problem to analyse the effect of including DER flexibility in physical and economic risk when considering scenarios of uncertainty.

In order to analyse economic risk, optimisation problems of planning under different risk perspectives of DSOs have been analysed in the literature. On the one hand, adopting a risk-neutral perspective and then calculating the expected net present costs (NPC) for both planning cases considering weighted-scenarios [33]. On the other hand, to quantify the value of flexibility studies have adopted risk-averse perspective approaches such as least-worst-regret [23],which minimise the regret felt by a decision maker after verifying that the decision made was not optimal given the occurred future, or min-max approach [48], which minimize the worst case scenario. In general, as it has been analysed in subsection b, when more uncertainty is considered, the cost reduction of planning with flexibility options become greater.

Moreover, in order to analyse physical risk, studies have incorporated constraints of reliability, such as SAIDI/SAIFI [30] so that the investment decisions are taken considering that the standards of performance of the network are kept under certain conditions against variability or intermittency of DERs. As another alternative, an additional layer of uncertainty has been developed in [37] to represent the availability to provide flexibility from DER and analyse the physical risk of relying on flexibility against network reinforcement through a iterative process that calculates the costs incurred in the case of no availability of flexibility providers. Similarly, in [32] an additional layer of uncertainty using Montecarlo simulations is developed to measure the excess load probability for a certain value of demand response contracted.

Furthermore, these studies often do not determine an optimal contract value per MW delivered to the grid to displace investments in network assets, usually taking these values input of the problem, but rather quantify the benefits based on the reduction in total costs at the end of the planning exercise compared to a planning considering only network assets options. In that way, an iterative process can be added to the optimization problem increasing the contract value for flexibility operation to obtain the break-even-point of contract of flexibility (e.g. the value of MW delivered at what the DSO do not see cost savings from acceding to flexibility), so that DSOs can estimate their flexibility budget plan [32].

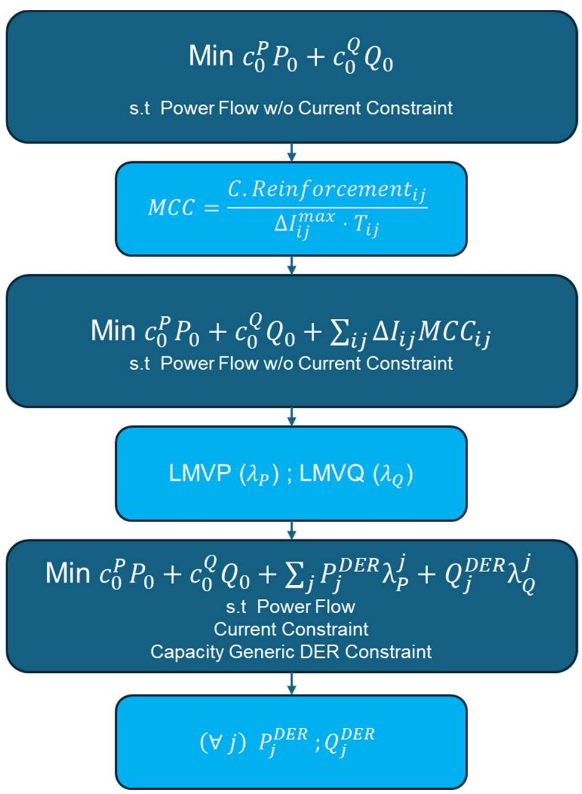
g. Marginal Cost Based Methodologies

Another approach of methodologies to find a ‘value to grid’ of DER technologies have been developed by using local marginal values to address the temporal valuation of DERs, considering their capacity to alleviate grid congestion and defer investments in grid reinforcements.

i. Marginal Capacity Cost – Based Methodology

In this methodology the valuation of DER is conducted through an iterative process, in which three consecutive optimisations are performed to derive an equivalent value of DER flexibility compared to traditional grid reinforcement. This value depends on the number of grid congestion events, the amount of power needed to overcome congestion, and the cost of traditional grid reinforcement. The Figure 8 provides a simplified schematic of the implementation of this methodology:

Figure 8:LMV-Based Methodology



This is the core of methodologies using marginal capacity costs to determine the capacity value of DERs, which is the cost of increasing 1 [MW] the capacity in a given element of the network[27]. The methodology uses as inputs network data, reinforcement project costs, wholesale prices of active and reactive power in the main substation and demand over the evaluation period.

Then, an optimisation problem is developed to minimize cost of power imports from the transmission grid without considering technical network limitations. The Marginal Cost of Capacity (MCC) is calculated based on the ratio between the network reinforcement cost $C.Reinforcement_{ij}$ and the number of congestion hours T_{ij} multiplied by the additional line capacity ΔI_{ij}^{Max}. This value is introduced into a new minimisation problem that seeks to reduce the payments incurred for linearized overloads ΔI_{ij} valued at MCC (e.g. monetise the value of relieving an overload).

Locational Marginal Values (LMVP and LMVQ) of DERs are then obtained which are the equivalent capacity prices that should be paid to DERs for their power provided and represent the equivalent value of DER against network reinforcement. It is important to highlight that these values will be equal to the marginal cost of substation + losses to any bus that is not connected to an overloaded line.

A final optimization problem is executed to evaluate DERs using LMVP and LMVQ as their operational costs, determining the DER power generation required to alleviate network congestion optimally.

The benefits of this methodology are firstly that allows DSO to temporally allocate, value and schedule the operation of DER throughout the planning horizon. Additionally, since the MCC is pro-rated to the capacity added and the number of hours of overload, it results in DER owners and customers sharing the avoided cost. If the entire avoided cost of planned traditional investments were included in MCC, then all the avoided cost could be captured by generic DERs, and customers/ratepayers would realize no net savings. In contrast, if no cost associated with DER power provision were considered, customers would realize savings for all the cost reduction of operating DER, but no benefits would be seen by DER owners which are operated arbitrarily.

One of the limitations of this technology is that it assumes that the demand growth in all nodes is fully known, which it is not likely to happen in the coming years. Additionally, the congestions of the network are assumed to only be caused by high demand periods but due to high integration of PV systems congestions as result of reverse power flow may occur. Finally, by modelling generic DER that are always able to provide enough power to alleviate constraints do not capture realistic DER behaviour since they have operational limitations, and DER allocation and size does not usually depend on DSOs.

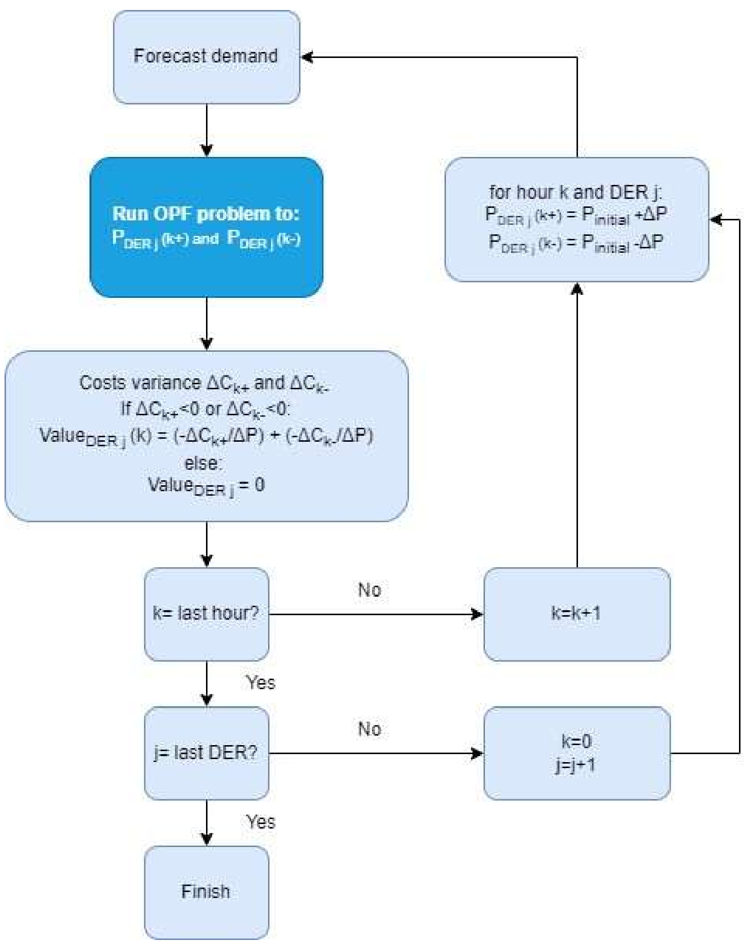
Regarding this last point, an iterative process proposed can be applied to combine DER deferral solutions and network assets investment when DER is not able to provide enough power, then calculating again the constraints of the system and the DER power procurement and its value until the system capacity is able to cope with all congestions [26]. On the other hand, to introduce uncertainty analysis over the demand, scenario-based analysis can be considered to analyse different demand growth levels in the planning horizon. Since the value of DER will depend on the demand in each bus of the system for each scenario of load a different value of DER will be obtained. In that manner, tools such as Monte-Carlo simulations to create scenarios of demand has been applied to calculate statistical metrics such as the probabilistic distribution of value of DER and total cost of planning compared with only network reinforcement solutions [49]. Additionally, decision ex-post simulations of small variations of the load can be conducted to measure physical risk given an adopted solution of DER contract power and network reinforcement [32].

ii. Disturbance Method

This method, also called Turvey Method [50] is based on the marginal changes in the forecasted demand/generation and their effect on the total cost of the planning problem, considering that the demand and generation over the period are fully known [51].

The methodology starts developing an optimal power flow over the planning horizon to determine the congested hours in the network and the potential costs of planning. Then, an iterative process is conducted where small increments/reductions of DER power ΔP are added to the forecasted net demand in all hours and DER buses to calculate variations of the total planning costs. Finally, since controllable DER will be required to operate to reduce network constraints, the value of each DER to each hour will be the systemic cost savings due to the injection or withdrawal of ΔP. This methodology has been applied to determine more cost-reflective distribution network tariffs in the UK considering the action of distributed generation [52]. This methodology is summarized in Figure 9:

Figure 9: Disturbance Method



This methodology, like the one presented in section G.i, has been studied in the literature assuming full knowledge of the system's forecasted demand, which has been proven to be unlikely in a context of high integration of active loads in future distribution networks[53]. Moreover, it addressed the problem of valuing DER flexibility from a point of view of operation rather than planning, since it does not consider the option of investing in the methodology and assumes that DER flexibility will have enough capacity to solve network constraints. One of the main differences in this method is that it incorporates demand variations in both direction (up and down of DER power), assigning value to DER not only when it relieves downstream network congestion but also upstream, in cases of high renewable energy penetration. Additionally, the value obtained corresponds to the marginal cost of using flexibility in the network to alleviate network congestion, which represents the cost savings from not investing in network assets, and this value is passed on to the DER. In this sense, since this value is transferred to the DER, the network operator does not see a cost reduction, and therefore, end consumers would not see a reduction in their network tariffs.

Since DER values depend on network conditions (the DER value is 0 if there is no network congestion), primarily determined by the system’s net demand, this methodology has been adopted under a deterministic approach. However, demand scenarios can be used to statistically assess the expected value of DER, considering demand scenarios with varying associated probabilities.

3. Conclusions

In the coming years, a massive growth in DER is expected, driven by the adoption of small and medium-sized generation and energy storage systems, as well as the electrification of various energy sectors, making customers active participants in the distribution network. This transition can be positive if there are schemes that increase user participation to enhance network flexibility.

Incorporating flexible DER into distribution system planning can unlock significant value, as it can reduce operational costs and defer network reinforcement investments, ultimately lowering the network tariff costs seen by end users. This has been demonstrated by various studies in the literature; however, these studies have been conducted with different approaches, making it necessary to develop a methodology that incorporates the key aspects needed to fully estimate the value of flexibility in DSP.

Findings from the literature show that the key factors in determining the value of flexibility are, on the one hand, the capacity and location of DER within the network. Depending on the position within the network and the capacity DER can offer (in terms of power and duration), it can alleviate network congestion to varying degrees. On the other hand, critical aspects of the methodology include the representation of uncertainty to analyse how integrating these technologies can mitigate risk. In this sense, results provided by the literature show that flexible DER helps reduce investment risk by allowing resources to adapt to different realizations of uncertainty, unlike traditional network assets. However, DER offers lower reliability, which creates trade-offs that must be analysed within the methodology on a quantitative basis, so that DSOs can choose between different strategies and estimate an equivalent value of DER compared to network assets.

With respect to this last point, methodologies to estimate DER value in the literature incorporate certain aspects but do not capture all the complexities that need to be considered to fully assess DER value in planning. This can also be observed in both the literature and methodologies adopted by various entities worldwide, which, although they provide a framework for evaluating DER capacity as a network option, often lack a structure to set prices for these services. Consequently, DER evaluation as a network option is often conducted through a deterministic approach.

Thus, it is necessary to develop a methodology that can assess the benefits of incorporating DER flexibility in planning by quantifying how these resources can help reduce investment risks under uncertainty. From this, a mechanism can be established to determine an equivalent value for DER to help DSOs set an appropriate price for flexibility and to enable regulators to evaluate whether this price is economically efficient.

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