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Analysis and implementation of Optimal Power Flow (OPF) tool for grid operation and planning under different future potential flexibility scenarios - Application to i-DE network.

Ricardo Noreña Alcalá-Galiano
Author

Raúl Bachiller Prieto
Industrial Advisor
i-DE Redes Eléctricas Inteligentes
(Grupo Iberdrola)

José Pablo Chaves Ávila
Academic Advisor
Instituto de Investigación Tecnológica
(IIT)

***Abstract*—Flexible resource optimization enables a more efficient grid operation without incurring in capital expenditures. This paper exposes the techno-economic benefits for a distribution system operator (DSO) of using transformer's on-load tap changers (OLTCs), shunt devices, distributed generation (DG) and flexible demand as potential flexible resources to optimize the operation of a real 20kV distribution network using an optimal power flow (OPF).**

***Keywords*— OLTC, DGs, Flexible demand, Shunt, OPF, DSO.**

I. Nomenclature

i	Bus number
U_i	Voltage magnitude at bus i
t_{OLTC}	OLTC transformation ratio
$Q_{sh.}$	Shunt nominal reactive power injection
$B_{sh.}$	Shunt nominal susceptance value
U_g	DG unit regulated bus voltage
Q_g	DG unit reactive power generation
P_g	DG unit active power generation
S_g	DG unit aparent power generation
P_{max}	DG unit maximum active power
P_{min}	DG unit minimum active power
Q_{max}	DG unit maximum reactive power
Q_{min}	DG unit minimum reactive power
S_{max}	DG unit maximum aparent power
x_d	Synchronous reactance
e_{fd_max}	Maximum excitation voltage
e_{fd_min}	Minimum excitation voltage
I_{s_max}	Maximum stator current
q_{nom}	Nominal reactive power
p_{max}	Nominal active power
q_{abs_max}	Maximum reactive power absorption
P_L	Flexible load from demand (power reduction)

II. Introduction

Traditionally, the distribution grid has been operated radially with a passive demand, where power flows go from the HV to the LV. In recent years, there has been an increase of Distributed Energy Resources (DER) such as distributed generators (DGs) powered by different technologies (cogeneration, renewable source…), electric vehicles (EVs) or demand response (DR) available in the distribution level.

These new flexible resources may become a challenge, increasing the complexity in grid operation, and causing issues in the equipment such as protections or transformer's On-Load Tap Changer (OLTC) due to the appearance of reverse power flows. But they offer plenty of opportunities as well, introducing new potential control variables that could lead to a more efficient operation, and cost-efficient alternatives to network investment.

The deployment of smart meters and automation equipment throughout the distribution network has enabled new remote control and supervision capabilities that did not exist in the past. Providing the necessary data infrastructure to run power flow calculations at the distribution level. This transition towards a smart grid is a necessary step for integrating the new flexible resources and be prepared for the upcoming scenario.

This paper reviews the potential control variables in the distribution grid given by the OLTCs, shunt elements, distributed generation, and flexible demand that could be used to optimize grid operation using an Optimal Power Flow tool (OPF). Defining some of the potential applications of the OPF tool, identifying the information required to parametrize each control variable in the software PSS®E and evaluating the techno-economic benefits by performing simulations over different flexibility scenarios in a real 20kV distribution network.

III. The Optimal Power Flow

The optimality problem appears in power systems when two or more generators must satisfy a given demand. The OPF determines the optimal power dispatch for each generation unit that minimizes total generation costs, keeping power flows within limits [1].

A formal formulation is presented in (1). The OPF determines the value of the set of control variables u $[t_{OLTC}, Q_{sh.}, U_g, P_g, P_L]$ which optimizes the objective function $f(x,u)$ while satisfying the equality and inequality constraints $h(x,u)$ and $g(x,u)$ respectively.

$$\begin{aligned} &Min. && f(x,u) \\ &Subject\ to && h(x,u)=0 \\ & && g(x,u)\geq 0 \end{aligned} \tag{1}$$

Several objective functions $f(x,u)$ may be defined, Fig. 1 provides the main applications given to the OPF tool for power system operation [1]. OPF objectives have been divided into three categories: Preventive Security Constrained OPF (PSCOPF), where security constraints are introduced to keep system variables within limits even after a contingency has occurred, secure state operation, which operates the system at its optimal point (minimizing losses or fuel costs) and emergency state operation, when the system is out of limits and the optimal corrective actions are determined to bring the system back to secure state, within limits.

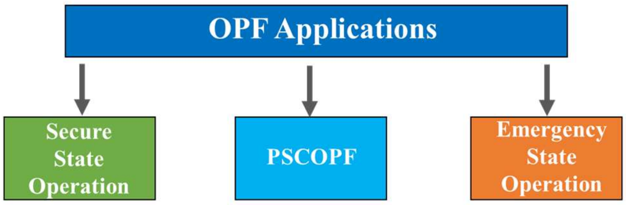

Fig. 1: OPF applications

At present, there is an economic incentive for Distribution System Operators (DSOs) to minimize power losses during grid operation, as well as reducing customer interruptions (NIEPI and TIEPI). Therefore, the OPF applications studied in this project are focused on the secure state and emergency state operation groups respectively.

IV. Distribution Grid Under Study

The distribution grid under study is shown in Fig. 2, it is a MV 20kV network owned and operated by i-DE, with a total of 247 buses and a high penetration of industrial loads and distributed generation (G1 to G10), most of them cogeneration from the industry. Generator units G1 to G6 will be used in the OPF.

The grid terminal nodes represent MV/LV secondary substations showing the aggregated load downstream. The secondary substations, also known as distribution transformers, can be owned by the client or by the DSO (i-DE), every big industrial consumer has its own distribution transformer.

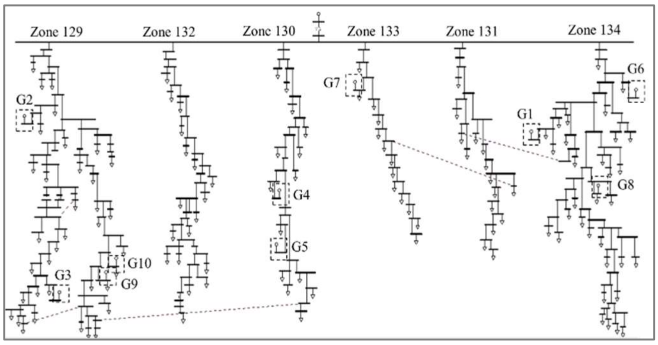

Fig. 2: 20kV real distribution network under study

The network is connected to the 66kV grid through a 66kV/20kV primary substation. The primary side of the transformer (66kV) has been considered as the slack bus, with a fixed voltage and reference angle.

V. Flexible Resources

Resources have been divided into 2 main groups as shown in Fig. 3: DSO owned equipment (On Load Tap Changers and shunt devices) and ancillary services provided by distributed resources (Distributed Generators and Demand Response).

Every flexible resource in the grid has control variables that could potentially be used in the OPF such as OLTC tap position, shunt element connection (reactive power injection), active power dispatch and reactive power regulation from DGs and demand load reduction.

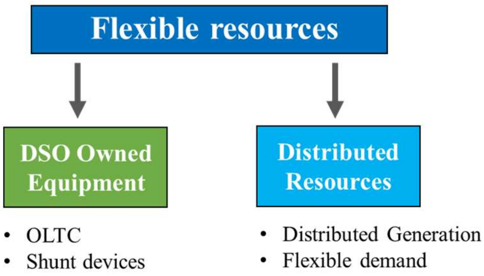

Fig. 3: Flexible resources classification

In a future context where a periodical OPF background execution is implemented during grid operation, control variables from DSOs owned equipment already installed such as OLTC tap position or shunt element connection will probably be the preferred controls to minimize losses, since they would have almost none Operational Expenditures (OPEX). However, new installations will have capital expenditures that need to be considered and compared with alternatives such as distributed resources which would incur operational expenditures (OPEX) [2].

Active power dispatch from generators and demand load flexibility could be used for contingency management in an emergency state operation. An overload can trip a line, leaving all the customers connected to it unenergized. Managing overloads in lines could also help in reducing minutes of non-served energy, which is another incentive in the DSO remuneration.

A. On-Load Tap Changer

Typically, primary substation transformers are equipped with on-load tap changers being able to modify their transformation ratio without de-energizing the transformer. Providing a control variable (t_{OLTC}) during operation to regulate voltages downstream.

Currently, OLTCs are managed in two ways, from the control center: the operator changes the tap position through a command or using a setpoint (voltage or tap position) which is managed by the transformer regulator unit at field to maintain the controlled voltage as close as possible to a reference value.

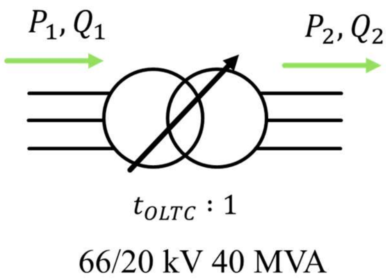

Fig. 4: Primary substation transformer with OLTC

Fig. 4 represents the 40 MVA, 66/20 kV primary substation transformer under study. An OLTC is placed on the primary winding (66kV) with 19 tap positions, regulating the secondary voltage (20kV).

Table I shows the transformation ratio (t_{OLTC}) for the central tap position (0) the maximum position (+9) and minimum position (-9). As the transformer's nominal voltage ratio is different from the grid nominal ratio 66kV/20kV, at the nominal tap position, the tap ratio is different to 1 pu.

TABLE I
OLTC TAP POSITIONS AND TRANSFORMATION RATIO IN PU

Tap position	Transformation ratio (t_{OLTC})
+ 9	1.008
0	0.916
-9	0.825

B. Shunt devices

At present, most of the shunt devices owned by i-DE are fixed value capacitor banks placed at the substation busbars. The connection of capacitor banks is made during demand peak hours where grid voltages are lower following a fixed pre-defined schedule independent from the actual status of the network, or connected by a manual operation. According to the sign criterion considered. The capacitor bank represents a positive nominal reactive power injection ($Q_{sh.} > 0$) and a positive susceptance ($B_{sh.} > 0$).

As demand profile depends a lot on the location and topology of the grid, peak hours are different depending on the substation and day studied. Making this fixed schedule approach, not the optimal one for every case. The OPF will use the shunt connection as a control variable to minimize power losses, the reactive power injection ($Q_{sh.}$) is zero when disconnected.

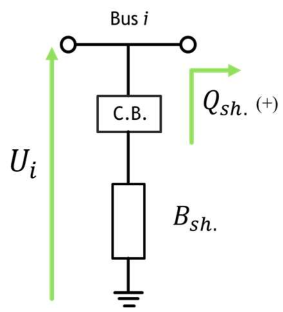

Fig. 5: Shunt device model

As there is not a capacitor bank in the actual network studied (Fig. 2), a modified base case including a shunt device (Fig. 5) in the primary substation busbar has been created. For this initial case, the shunt initial connection scheduling has been considered from 7:00h to 13:00h and 18:00h to 21:00h.

C. Distributed generators

Distributed generators offer an opportunity for Active Network Management (ANM) to operate the grid more efficiently. They are currently modelled by some of the i-DE electrical applications as negative fixed PQ loads generating active power at a fixed power factor with no control over the reactive power outputs.

Reactive power control of DGs can be used for minimizing technical losses as shown in [3]. Currently, the voltage/reactive power service regulatory framework and remuneration mechanisms are under discussion. It has been assumed a regulatory framework where flexibility services from these generators can be used by the DSO in exchange of remuneration (OPEX).

Two kinds of generation technologies are present in the distribution network under study: Combined heat and power (CHP) cogeneration for G1, G3, G4, G5 and G6 modelled as synchronous machines (Fig. 6) and a wind farm for G2 modelled as an inverter-connected plant (Fig. 7).

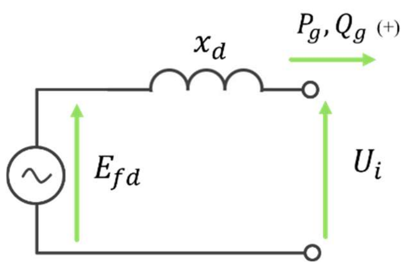

Fig. 6: CHP synchronous machine model (G1,G3,G4,G5,G6)

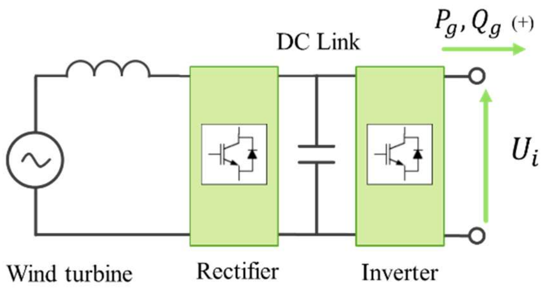

Fig. 7: Inverter-connected wind farm model (G2)

In the optimal power flow model, DGs are able to work as PV node generators, setting their active power injection P_g and regulating their bus voltage U_g. By controlling their reactive power output (Q_g) the OPF fixes the optimal voltage setpoint that optimizes the objective function (within PQ operational limits). The active and reactive power limits for the most common generation technologies are described in [4]. Fig. 8 represents the PQ constraints used for the CHP cogeneration plants in pu units.

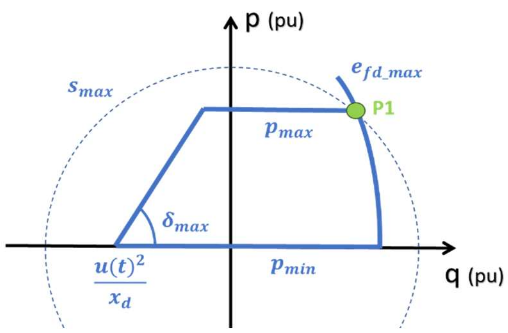

Fig. 8: Synchronous Generator (CHP) PQ Diagram in pu

Where the most important constraints are:

- Maximum excitation voltage in pu:

$$e_{fd\_max} = \sqrt{x_d{}^2 \cdot \left(p_{max}{}^2 + \left(q_{nom} + \frac{1}{x_d}\right)^2\right)} \quad (2)$$

- Minimum excitation voltage in pu:

$$e_{fd\_min} = 1 - x_d \cdot |q_{min}| \quad (3)$$

- Active power generation limits:

$$P_{min} \leq P_g \leq P_{max} \quad (4)$$

- Stator current limit:

$$S_g = \sqrt{{P_g}^2 + {Q_g}^2} \leq S_{max} \quad (5)$$

Fig. 9 shows the PQ constraints used for the inverter module of the wind plant G2.

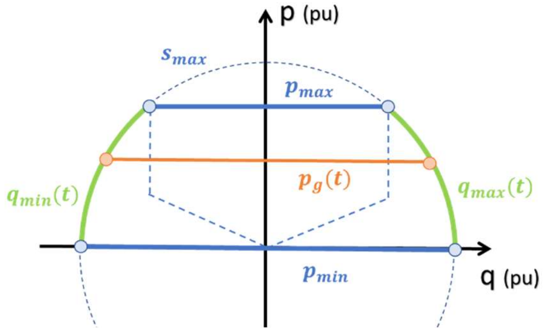

Fig. 9: Inverter PQ limits in pu. Total reactive capability (green). Typically used PQ capability (dashed blue line). Operational point (orange).

Where the reactive output is now constrained at every hour by the following limit:

$$\begin{gathered} |Q_{limit}| = \sqrt{{S_{max}}^2 - {P_g}^2} \\ Q_{min} = -Q_{limit} \\ Q_{max} = Q_{limit} \\ Q_{min} \leq Q_g \leq Q_{max} \end{gathered} \quad (6)$$

Table II shows the parametrization used in PSS®E for each of the distributed generator models. For the synchronous machine, the '*reactive capability model*' have been used. Generator G2 has been modelled as a PV node generator, regulating its bus voltage with the reactive power limits calculated as (6) for every hour.

TABLE II
DISTRIBUTED GENERATORS PARAMETRIZATION

Generators	Parametrization
G1, G3, G4, G5, G6	CHP (Synchronous machine) *Reactive capability model* x_d =1.8 pu I_{s_max} = 1pu Nominal leading power factor: 1 Nominal lagging power factor: 0.8 q_{abs_max} = 0.4 pu
G2	Wind farm (Inverter-connected) *Regulated PV node* Reactive power limits calculated every hour: $Q_{max} = \sqrt{{S_{max}}^2 - {P_g}^2}$ $Q_{min} = -Q_{max}$

D. Flexible Demand

This project studies the potential application of demand flexibility for optimal contingency management during an emergency state operation.

Two types of flexible loads with different costs and participation share have been considered in this project, industrial and residential loads, depending on whether the secondary substation is owned by the client or by the DSO (i-DE).

VI. SYSTEM CONSTRAINTS

A. Bus voltages

By regulation, Distribution System Operators must operate the grid to maintain supply voltages within some limits ensuring a secure and reliable supply. The Spanish regulation for the activities of transport, distribution, and supply of electricity (RD 1634/2006) [7] imposes a maximum variation limit at the final consumer's supply voltage of 7%.

Therefore, a maximum variation limit of 7% at every bus voltage has been imposed. Excluding the slack bus (primary substation 66kV bus) which is fixed to its initial value. This inequality constraint has been treated in PSS®E as a *'hard limit'* restriction [6]. This limit type introduces a logarithmic barrier term in the objective function, enforcing the variable to be within the feasible region in the final OPF solution.

B. Branch flows

Branch flows are currently modelled in some of the i-DE electrical applications with two different ratings, a summer, and a winter rating. Being the summer rating the most restrictive one. A '*reporting'* limit type has been considered in PSS®E, which does not include any penalty term in the objective function, allowing the variable to go out of the feasible range [6]. If any overload occurs, it will be reported in the final solution.

VII. SIMULATIONS METHODOOLOGY

First, control variables associated to each flexible resource have been modelled and parametrized. Secondly, benefits of applying an OPF in a real 20kV distribution network under different flexibility scenarios are evaluated and compared with the initial case. Finally, a sensitivity analysis is performed, determining for different flexibility scenarios, which are the most effective controls.

Project simulation's methodology can be resumed in the following steps:

- Base case scenarios from a real distribution network are obtained from the state estimator PSE (i-DE tool), analyzed using PSS®E and Python to automatize the 24h executions [5]. Obtaining the base case results.
- Optimization cases are defined for each of the flexible resources (OLTC, shunt device, DGs and flexible demand) evaluating different objective functions by using their available control variables (tap position, shunt device connection, active and reactive power regulation from DGs and demand load reduction).
- For the flexibility cases simulated, impacts of using each control variable are evaluated and compared with the initial case scenario results.
- With results obtained, a sensitivity analysis is performed, determining for different flexibility scenarios, which are the most effective controls.

Table III describes which are the objective functions, flexible resources and control variables used within each of the OPF simulations performed.

TABLE III
OBJECTIVE FUNCTIONS, FLEXIBLE RESOURCES AND CONTROL VARIABLES USED IN EACH SIMULATION

Simulation	Objective functions	Flexible resources	Control variables
Case 1	*Minimize Losses*	OLTC	Tap position
Case 2	*Minimize Losses*	Shunt device	Substation busbar Shunt connection decision
Case 3	*Minimize Losses*	DG	Volt/VAr regulation from DGs
Case 4	*Minimize Bus Load* *Minimize Fuel Cost*	DG & Flexible demand	Power dispatch (G1) Load shedding from industrial and residential flexible loads

Simulation cases 1 and 2 use the DSO owned flexible resources, controlling the OLTCs tap position and shunt device reactive injection (optimal connection schedule) variables respectively for power losses minimization. Simulation case 3 uses DGs Volt/VAr regulation, controlling their reactive power injection to obtain the optimal voltage profile that minimizes power losses. Evaluating their sensitivity with the objective function and their effect on other electrical variables such as voltages or power flows. Simulation case 4 uses active power flexibility of demand and DG power dispatch to eliminate an overload in a line.

Cases 1 to 3 correspond to a secure state operation where the optimal operation point with minimal losses is found. Case 4 corresponds to an emergency state operation where an emergency state operation. Obtaining the most cost-efficient control actions under different load-shedding costs to bring the system back into limits.

VIII. RESULTS

Fig. 10 shows the 24-hour power loss reductions obtained with respect the initial scenarios considered for secure state optimization cases 1 to 3, where OLTC tap position, shunt device connection schedule and reactive power from DGs are optimized respectively

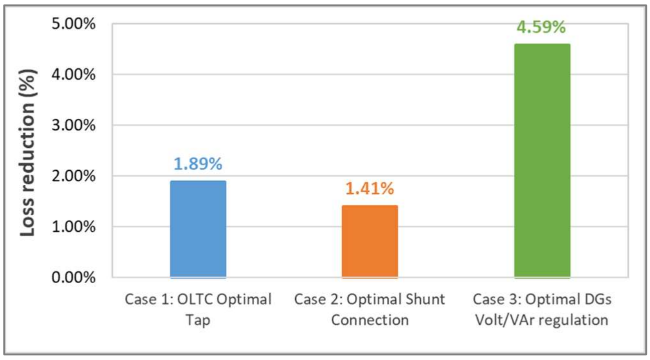

Fig. 10: 24 hour loss reduction for OPF secure state cases 1 to 3

A. *Optimal Tap Position*

Fig. 11 shows the optimal OLTC tap positions that minimizes losses during the 24h studied.

For the OLTC parametrization in PSS®E, tap positions have been treated as a continuous variable. Meaning that the OPF will provide the optimal transformation ratio that leads to minimal power losses (blue line in Fig. 11), without considering the real discrete steps restriction of the OLTC. This value has been discretized afterwards (green line in Fig. 11), by using an external logic to obtain a feasible and optimal tap position for the OLTC.

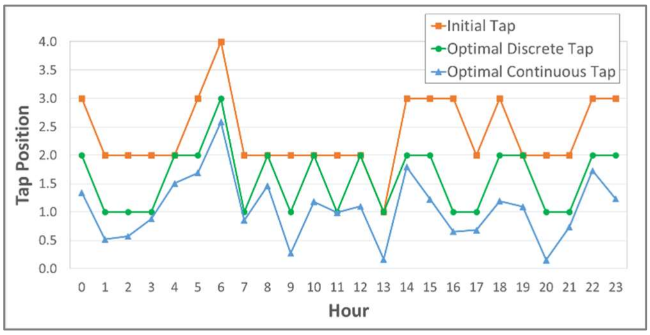

Fig. 11: 24 hour optimized tap position

The direct effect observed when minimizing losses is that transformer's tap ratio (tap position) is reduced. This causes the secondary voltage to increase, rising the voltage profile of the network, which leads to a reduction in branch currents and therefore power losses.

Fig. 12 shows the network voltage profile for the initial case and the discrete and continuous optimizations for the peak hour case (20:00h). For this hour, the initial tap position is 2 and the optimal continuous tap recommended by the OPF is 0.2. Which is rounded afterwards to the next upper discrete value 1, obtaining the optimal discrete tap. The network voltage profile increases proportionally with the decrease in the OLTC tap position.

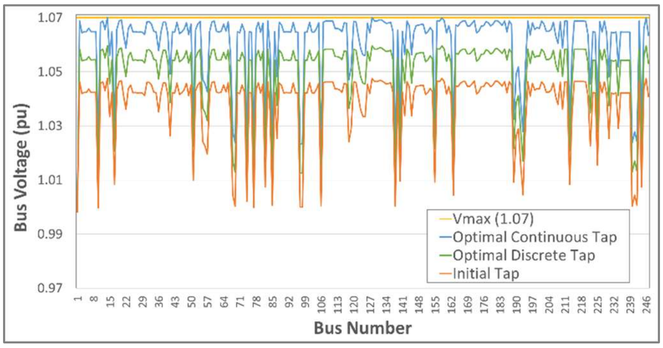

Fig. 12: Peak hour (20:00h)system voltage profile depending on tap position

The OPF has proven to be a useful tool for finding the optimal operational point with minimal losses. Obtaining a 24h losses reduction of **1.89%** by managing the tap position of the OLTC.

B. *Optimal Shunt Schedule*

Fig. 13 shows in green the optimal connection schedule for a 4 MVA shunt device connected to the substation busbar, considering an initial case with the OLTC tap position fixed at position 3. The *optimal adjustable shunt model* in PSS®E has been used in combination with the fixed shunt model, to evaluate the optimal hourly connection of the 4 MVA fixed shunt device. When the adjustable shunt value is greater or equal to 4 MVA, the fixed shunt device is connected. Otherwise, it is not connected.

The adjustable shunt value shown in blue in Fig. 13, represents the maximum (optimal) capacitor bank size, that minimizes losses within system limits, meaning that for this shunt value, it is bounded at some of the network buses by the 7% upper voltage limit.

For the shunt connection base case, the peak load hours for the initial shunt connection schedule have been considered from 7:00h to 13:00h and from 18:00h to 21:00h, similarly as it would be done in real life.

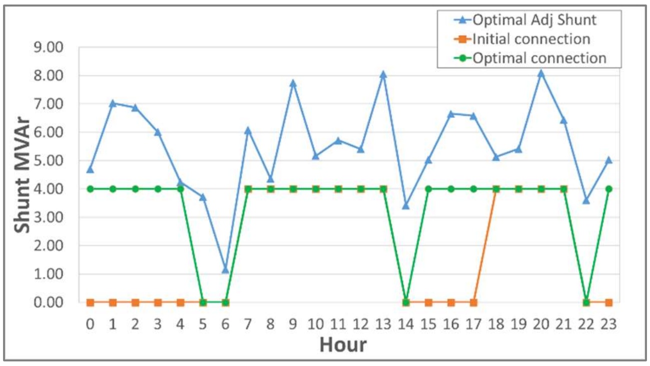

Fig. 13: 24 hour optimized substation busbar shunt connection

The OPF has proven to be a useful tool for finding the optimal operational point with minimal losses obtaining a reduction of **1.41%** when optimizing the substation's capacitor bank connection schedule

C. Optimal DG Volt/VAr control

Distributed generators are treated initially as PQ nodes with a fixed power factor of one. Fig. 14 shows every generator's initial reactive power sensitivity with respect to power losses in €/pu, using a 100 €/MWh losses cost. These sensitivities are negative for every hour, representing the expected reduction in € in the objective function when an extra pu unit in the reactive power constraint is relaxed. It can be noticed how DGs located more downstream the primary substation show a higher sensitivity in absolute value at every hour. Meaning that these are the most effective generators in reducing losses by injecting reactive power.

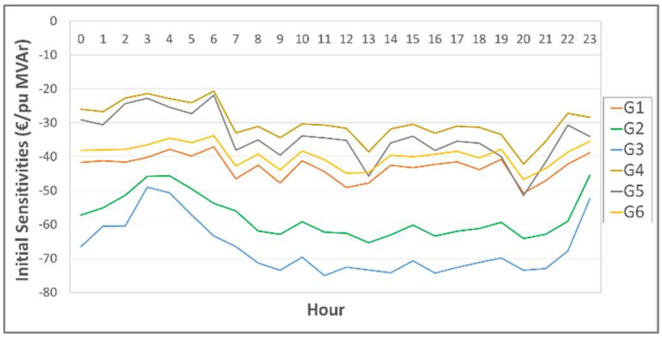

Fig. 14: Initial DG reactive power sensitivity

The global effect of using the reactive power from distributed generators is similar to the optimal shunt element case. As it can be seen in Fig. 15, the total optimal amount of reactive power provided by the DG (dashed blue line) has a similar shape to the optimal adjustable shunt chart for the initial base case scenario shown in Fig. 13. Comparing both charts, DGs prove to be more efficient than the substation adjustable shunt in reducing losses.

Using DG's reactive flexibility, results in a fewer amount of reactive power required and a higher reduction in power losses at the optimal point. The DG's inject reactive power in a distributed way downstream, which results to be a more optimal location for reducing power losses than injecting reactive power upstream in the substation (higher sensitivity is achieved downstream).

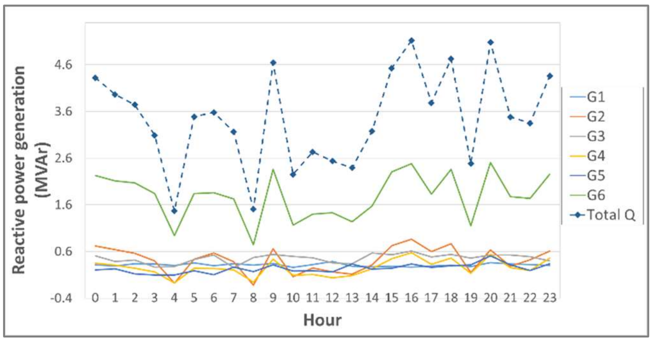

Fig. 15: 24 hour optimal DGs reactive power output

Final reactive output sensitivities obtained at the optimal solution for every hour and generator are zero, meaning that at the optimal solution, every generator is able to provide the optimal reactive power amount that leads to minimal losses within the 7% voltage limit and it is not limited by its PQ curve constraints.

The OPF has proven to be a useful tool for finding the optimal operational point with minimal losses obtaining a reduction of **4.59%** when using the reactive power regulation from DGs.

D. Emergency state operation optimal control

In order to create an overload for the emergency state scenario, Zone 131 clients have been transferred to Zone 134 opening the line inside the red box (Fig. 16) and closing the line inside the green box.

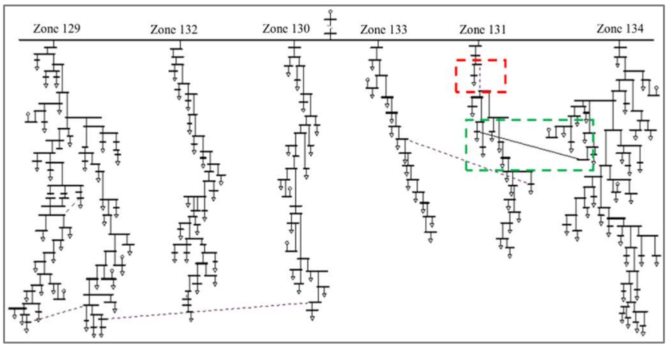

Fig. 16: Emergency state scenario

Generator G1 active power dispatch, with a marginal cost of 60 €/MWh and Zone 131 & 134 industrial and residential flexible demand have been used in the OPF. Table IV shows the OPF solution to the emergency state operation case under different load-shedding cost scenarios. Providing the control actions taken to eliminate the overload, showing the associated cost increment with respect the initial case.

The OPF has solved the emergency state situations by providing the optimal corrective control actions in terms of cost-efficiency for the flexible resources available. As shown in Table IV different flexible loads may be defined in the OPF, with different quantities and costs. For a low load-shedding cost scenario, below the generator's marginal fuel cost, demand flexibility has been used to solve the contingency. For a high load-shedding cost scenario, above the generator's marginal fuel cost, demand flexibility is not used, incurring higher costs.

TABLE IV
CASE 4 EMERGENCY STATE OPERATION

Emergency state operation	Generator marginal cost (€/MWh)	Load Type	Cost (€/MWh)	Load Flexibility use (%)	Total cost increment (€/h)
High load-shedding cost	60	Residential	70	0%	13.6
		Industrial	80	0%	
Medium load-shedding cost	60	Residential	50	10%	13.3
		Industrial	65	0%	
Low load-shedding cost	60	Residential	40	10%	2.5
		Industrial	45	10%	

IX. CONCLUSIONS

This project analyzes the benefits of using OLTC, shunt device, DGs and flexible demand as potential flexible resources and their available control variables (OLTC tap position, Shunt element connection, active and reactive power regulation from DGs and demand load reduction) to optimize grid operation using an OPF.

The OPF has proven to be a useful tool for finding the optimal operational point with minimal losses. The direct effect observed when minimizing losses is an increase in the network's voltage profile by using the associated control variable: decreasing OLTC tap position or injecting reactive power into the network with resources such as shunt devices or DGs. A rise in voltages leads to a reduction in branch currents and therefore power losses.

DGs have proven to be the most efficient control due to their more optimal location. DGs located more downstream from the primary substation, show a higher sensitivity to reduce power losses.

During the OPF problem configuration, it is very important to define coherent cost/weights to the objective terms and configuration parameters to conduct the solution in the desired direction. When applying hard limits to the bus voltages, losses cost coefficient greater than 1000 €/pu must be applied to minimize the power losses.

The OPF has been able to solve an emergency state scenario by providing the optimal corrective control actions in terms of cost-efficiency.

Flexible resources optimal control allows a more efficient grid operation at the cost of operational expenditures (OPEX). Under this new potential flexibility scenario, during the planning and operation of the distribution grid capital expenditures (CAPEX) for new installations must be evaluated and compared with the OPEX of existent grid flexible resources to obtain the most cost-efficient alternatives.

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