# GWP3 – gD3.8 GRID4EU Replicability at International level

## Application of GRID4EU SRA to California and Brazil

CO - FUNDED BY THE EUROPEAN UNION

*This project has received funding from the European Union's Seventh Framework Programme for research, technological development and demonstration under grant agreement n°268206.*

| | | | |
|---|---|---|---|
| **ID & Title :** | gD3.8. GRID4EU Replicability at International Level. Application of GRID4EU SRA to California and Brazil. | | |
| **Version :** | V5.0 | **Number of pages :** | 68 |

**• Short Description**

This report evaluates the extent to which the technical SRA rules presented in previous GWP3 reports would be applicable to contexts with different technical and regulatory boundary conditions. The cases of California and Brazil have been selected as both regions are active in the areas of renewable energy and smart grids. Furthermore, network characteristic and regulatory context in these two regions are noticeably different from the EU, thus enabling a wider and more comprehensive SRA analysis.

**• Revision history**

| Version | Date | Modifications' nature | Author |
|---|---|---|---|
| V0.0 | 05/10/2015 | Document initialization | Comillas |
| V1.0 | 15/01/2016 | First draft | Comillas |
| V2.0 | 20/01/2016 | Update on technical SRA results | Comillas |
| V3.0 | 23/01/2016 | Update on non-technical SRA results | Comillas |
| V4.0 | 27/01/2016 | Conclusions + executive summary | Comillas |
| V5.0 | 29/01/2016 | Final version for approval | Comillas |

**• Accessibility**

| | | | |
|---|---|---|---|
| ■ Public | ☐ Consortium + EC | ☐ Restricted to a specific Group + EC | ☐ Confidential + EC |

If restricted, please specify here the group

**• Owner / Main responsible**

| Name (s) | Function | Company | Visa |
|---|---|---|---|
| Rafael Cossent, Andrea Rodríguez, Pablo Frías | SRA Responsible | Comillas | Comillas |

**• Author (s) / Contributor (s) : Company name (s)**

Comillas University

**• Reviewer (s) : Company name (s)**

| Company | Visa |
|---|---|
| CEZ Distribuce, ENEL Distribuzione, ERDF, IBERDROLA Distribucion, RWE, VATTENFALL Eldistribution, Comillas, KU Leuven & RSE | Review validated by Technical Committee on January 29th 2016 |

**• Approver (s) : Company name (s)**

| Company | Visa |
|---|---|
| CEZ Distribuce, ENEL Distribuzione, ERDF, IBERDROLA Distribucion, RWE, VATTENFALL Eldistribution | Approved by Steering Committee on January 29th 2016 |

| | | | |
|---|---|---|---|
| **Work Package ID:** | **GWP3** | **Task ID:** | **GWP3.7** |

# Executive summary

Previous work within the GRID4EU project, evaluated the effect of different boundary conditions on the potential for upscaling and replication of the tested use cases focusing on the 6 demo countries, namely: Germany, Sweden, Spain, Italy, Czech Republic and France. One of the lessons learnt from such an exercise was that, despite the fact that DSO size or ownership may vary greatly across Europe, the characteristics of distribution networks and operational approaches are relatively homogeneous across European countries. Therefore, the SRA results could be broadly applicable on a wider European context, provided the relevant parameters identified are considered.

However, the applicability of the GRID4EU SRA rules to non-EU contexts, where the boundary conditions may be significantly different, could be more challenging. Addressing this concern, this report has evaluated the extent to which the aforementioned rules could be applied to other contexts. In order to perform such an analysis, two regions have been selected; the state of California (US) and Brazil. Both regions are active in terms of RES integration and smart grid deployment. Additionally, their distribution sectors and regulatory frameworks are distinctly different both among them and when compared to the European countries for which the SRA rules were developed. This provided suitable conditions for a wider analysis of the applicability and limitations of these rules.

A comparative assessment between GRID4EU countries and the selected regions was performed, attending to the most relevant boundary conditions, i.e. those with a stronger impact on the KPIs. This comparison has allowed obtaining qualitative indications of the potential impact and suitability of GRID4EU solutions in Brazil and California. The assessment of the upscaling and replicability potential has been divided into two subsequent steps: i) evaluation of the effect of technical boundary conditions related to distribution networks and ii) characterization of non-technical boundary conditions related to regulatory frameworks and stakeholders aspects. The main conclusions drawn from each of these two steps are summarized on the ensuing.

*Upscaling and replication: technical boundary conditions*

A detailed analysis of the technical boundary conditions has been carried out for both California and Brazil, comprising: distribution grid characteristics, performance indicators (continuity of supply, energy losses), smart metering status, and installed DG. These parameters have been compared with the data compiled from the GRID4EU demo countries. It has been shown that distribution networks in California and Brazil are quite different from European ones, particularly with respect to the design of LV networks. For instance, in Brazil and California, contrary to European countries, there are no secondary substations as such. Instead, distribution transformers, much smaller in size, switchgear and protection equipment are spread throughout the network. The implications of this and other differential features are manifold concerning GRID4EU uses cases implementation:

- **Demand response:** unlocking demand flexibility is a major target both in California and Brazil thus being GRID4EU solutions in this respect widely replicable. The situation in California can be considered to be similar to many European countries since this region is facing a growing penetration of intermittent generation in a system based on thermal generation. On the contrary, Brazil is already a quite flexible system since it is based mostly on hydro power. However, scarcity periods may occur during dry years, when demand response, e.g. in the form of critical peak pricing, could significantly alleviate the need for additional capacity.

- **Voltage/load control in MV to increase NHC:** current moderate DG penetration in MV does not presumably cause major voltage problems at the moment. In fact, relays preventing reverse power flows are deployed in California. However, the hosting capacity of MV networks in Brazil and California can be expected to be lower than in GRID4EU countries due to the generally lower rated voltages, longer feeders, higher R/X ratios and tighter voltage limits (which are well below the 10% stipulated in standard EN50160). Therefore, voltage control strategies may gain in relevance and replicability potential. In this regard, in both contexts analyzed, the presence of OLTCs and voltage regulators, capable of correcting the voltage in case of unbalanced feeders outgoing of the same substation, render DG power factor control less attractive than in the EU.
- **Voltage/load control in LV to increase NHC:** DG penetration in the LV is very low in Brazil nowadays. Hence, the need for this use case is not foreseen in the short to medium term. However, since this country presents long three-phase LV lines this conclusions may need to be revisited if small-scale DG grows significantly in order to tackle both phase unbalances and voltage issues. On the other hand, LV DG is already widespread in California. However, since LV lines are very short and single-phase, this use case is not a priority for distribution utilities.
- **Distribution automation:** this type of smart grid solution presents a significant potential in MV urban networks, both in Brazil and California. In these areas, the distribution network is meshed and could be reconfigured, as proven by the several ongoing demonstration projects. However, the SRA rules and the definition of the degree of automation developed for EU countries are not directly applicable due to the different network designs. Instead of at secondary substations, automation points would be placed at the NO switches that connect neighbouring feeders. Thus, new indicators and simulations may be needed so as to infer quantitative rules.
- **LV supervision:** this functionality is not very relevant for California owing to the fact that LV networks are very short and connect a very low number of consumers. Moreover, load unbalance correction would not make sense since Californian LV grids are usually single-phase. On the contrary, LV supervision presents a significant replicability potential in Brazil, not because of unbalances as DG penetration is rather low, but because of the extremely high levels of losses. Thus, LV monitoring could support distribution companies in their loss reduction efforts. Nonetheless, the communications architecture may need adaptations in response to: different network topology, highly scattered population and communications availability in remote areas.
- **Anti-islanding:** the current potential for this solution is quite limited in Brazil, owing to the little presence of PV in the MV network. On the contrary, there is an actual concern about this issue in California and a significant potential in the medium term. Current DG penetration levels are still moderate. However, utilities are already evaluating the use of communications-based disconnection systems to face higher penetrations of DG.

*Upscaling and replication: non-technical boundary conditions*

As a complement to the previous technical evaluation of the replicability potential of GRID4EU solutions, the barriers and drivers posed by non-technical boundary conditions have been explored for California and Brazil. The focus was mainly placed on the differential regulatory settings in these regions as compared to the EU context. The topics analyzed included: distribution regulation, smart meter deployment, RES promotion policies, self-consumption, energy storage, incentives for smart grid demonstration projects and treatment of DG units. Additionally, some noteworthy stakeholder issues have been discussed. The main lessons learnt from this analysis are the following:

- **Distribution regulation:** current regulatory frameworks in these regions provide distribution companies with virtually no incentive to defer investments, either because of a cost of service regulation (California) or, similarly to several EU countries, due to a separate treatment of CAPEX and OPEX under incentive regulation (Brazil). Thus, several smart grid solutions may be hampered. Notwithstanding, the Californian framework may be more easily adapted in the short-term since distribution utilities are already required to perform forward-looking business plans, which need to explicitly consider the presence of DER.
- **Performance indicators:** the existence of incentives to improve continuity of supply levels in both regions, together with the relatively poor quality levels (especially in some areas of Brazil), are important enablers for MV automation. On the other hand, energy losses are seen as a major concern in Brazil, particularly non-technical ones. Nevertheless, despite the fact that distribution companies are indeed encouraged to reduce these losses, the very low market prices for most of the time dilutes the power of these incentives, thus being a barrier for LV supervision replication. Lastly, the stringent voltage limits and financial penalties faced by Brazilian firms can be a potential driver for voltage control functionalities if DG penetration increased in the future.
- **Smart metering deployment:** barriers to the deployment of smart meters, necessary for LV supervision and demand response, can be found in both non-EU regions. A large-scale roll-out of AMI has already been carried out in California. However, an opt-out clause was introduced as a result of public concerns about health and privacy. On the other hand, the opt-in policy adopted in Brazil usually results in lower adoption rates. Moreover, the roll-out has stagnated due to the existing uncertainties on technical requirements. On the plus side (for smart meters), distribution companies in both regions are vertically integrated. Hence, contrary to the European context, there is no discussion about the fact that these companies are responsible for meter deployment, reading and data management.
- **Islanding and microgrids:** islanding solutions present an important replicability potential in California in the form of microgrids at the premises of sensitive loads, driven by security and resiliency concerns. In fact, since the focus is placed on consumer microgrids instead of utility microgrids, as in GRID4EU demos, the potential regulatory barriers would be much more easily overcome. On the other hand, microgrids for the electrification of remote areas show a limited potential since both California and Brazil present very high degrees of electrification.

- **Unbundling:** as mentioned above, Californian and Brazilian distribution companies are vertically integrated. This is not seen as a major concern since a competitive retail market is not a policy priority at the moment. This fact simplifies AMI deployment models and demand response schemes, although these become fully subject to the willingness of the incumbent utilities. Likewise, storage-based solutions, which in Europe are hindered by unbundling rules (besides economic reasons), are more straightforward as the utility may own and operate the installations.

# Table of contents

# List of figures

# List of tables

# 1 Introduction and scope of the document

## 1.1 Scope of the Document

Previous GWP3 reports have analyzed in detail the scalability and replicability potential of GRID4EU smart grid solutions in the European context, particularly considering the six demo countries, namely Germany, Sweden, Spain, Italy, Czech Republic and France. As a basis for the technical analyses, detailed network information was collected from the participating DSOs so as to characterize distribution grids in these countries and build a set of representative networks on which to perform simulations. Furthermore, non-technical boundary conditions were evaluated based on regulatory questionnaires, surveys and publicly available information. The full results on this SRA have been presented in gD3.4 and gD3.5.The applicability of the results obtained was then tested on the Belgian case as presented in gD3.7.

One observation obtained from the previous work was that despite the fact that DSO size or ownership may vary greatly across Europe, the major characteristics of distribution networks and operational approaches are relatively homogeneous across European countries. Hence, the technical SRA results obtained could be broadly applicable on a wider European context, considering the specific local network conditions. A similar conclusion could be applicable to some non-technical boundary conditions within the EU as a result of the existence of common EU legislation and supra-national institutions, e.g. DSO unbundling rules or harmonization efforts and knowledge-sharing among member states done by CEER. However, the application of the SRA results presented in previous deliverables to contexts outside the EU could be more challenging given the important differences that may exist with respect to distribution network structural design and operation criteria, as well as organizational and legal backgrounds.

Therefore, in order to address this question, this report evaluates the extent to which the technical SRA rules presented previous reports would be applicable to other contexts and what the main limiting factors would be. More specifically, the cases of California and Brazil have been selected.

## 1.2 Structure of the Document

After this introductory section, the remainder of this report is organized as follows. Section 2 briefly outlines the rationale and drivers for the realization of this report as a continuation of previous deliverables published within GWP3 and provides the general background for the two regions selected for this analysis, i.e. California and Brazil. Section 3 discusses the applicability of the technical SRA results obtained in previous tasks in the contexts of California and Brazil, attending to the characteristics of distribution networks in these regions as compared to the EU context. Subsequently, section 4 shifts the focus of the discussion to the non-technical boundary conditions affecting scalability and replicability of GRID4EU solutions in California and Brazil, with an emphasis on regulatory issues. Lastly, section 5 presents some concluding remarks.

## 1.3 Notations, abbreviations and acronyms

| | |
|---|---|
| ABRADEE | Brazilian Association of Energy Distribution Companies |
| AMI | Advanced Metering Infrastructure |
| AMR | Automatic Meter Reading |
| ANEEL | Brazilian Electricity Regulatory Agency |
| ARRA | American Recovery and Reinvestment Act |
| CAIDI | Customer Average Interruption Duration Index |
| CAISO | California ISO |
| CAPEX | Capital Expenditures |
| CBA | Cost-benefit Analysis |
| CCEE | Chamber for Electric Energy Trading (Brazil) |
| CfD | Contract for Differences |
| CHP | Combined Heat and Power |
| CSI | California Solar Initiative |
| DEA | Data Envelopment Analysis |
| DEC | Duração Equivalente de Continuidade |
| DER | Distributed Energy Resources |
| DG | Distributed Generation |
| DMS | Distribution Management System |
| DOE | Department Of Energy (US) |
| DRAM | Demand Response Auction Mechanism |
| DRP | Distribution Resource Plan |
| DSM | Demand Side Management |
| DSO | Distribution System Operator |
| EU | European Union |
| EV | Electric Vehicle |
| FDIR | Fault Detection, Isolation and service Restoration |
| FEC | Frequência Equivalente de Continuidade |
| FERC | Federal Energy Regulatory Commission |
| GIS | Geographic Information System |
| GPRS | General Packet Radio Service |
| GSM | Global System for Mobile Communications |
| GWP | General Work Package |
| HV | High Voltage |
| IOU | Investor Owned Utility |

| | |
|---|---|
| ISO | Independent System Operator |
| KPI | Key Performance Indicator |
| LV | Low Voltage |
| MAIFI | Momentary Average Interruption Frequency Index |
| MV | Medium Voltage |
| NHC | Network Hosting Capacity (for DG) |
| NO | Normally-Open |
| OLTC | On-Line Tap Changer |
| OMS | Outage Management System |
| ONS | Operador Nacional do Sistema Eletrico (Bazilian ISO) |
| OPEX | Operational Expenditures |
| PBR | Performance-Based Regulation/Ratemaking |
| PG&E | Pacific Gas & Electric |
| PLC | Power Line Communication |
| PNNL | Pacific Northwest National Laboratory |
| PUC | Public Utilities Commission |
| PV | Photovoltaics |
| RAB | Regulatory Asset Base |
| RES | Renewable Energy Sources |
| RPI | Retail Price Index |
| RPS | Renewable Portfolio Standard |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCE | Southern California Edison |
| SDG&E | San Diego Gas & Electric |
| SGDP | Smart Grid Demonstration Projects |
| SGIG | Smart Grid Investment Grant |
| SRA | Scalability and Replicability Analysis |
| T&D | Transmission and Distribution |
| TOTEX | Total Expenditures |
| ToU | Time of Use |
| TSO | Transmission System Operator |
| US | United States (of America) |
| WACC | Weighted Average Cost of Capital |

**Table 1: Acronyms**

# 2 Replicability potential outside the EU: drivers and selection of contexts

The scope of GRID4EU SRA presented in previous project deliverables was limited to the EU context, with a particularly emphasis on the six demo countries of the project. Nonetheless, this report broadens this scope by assessing the potential applicability of SRA results to areas beyond the EU. The proposed approach consists in performing a high-level qualitative evaluation of the potential barriers and drivers for the implementation of GRID4EU smart grid solutions in a few selected regions outside the EU. More precisely, this report focuses on the influence of the following parameters on the potential outcome of GRID4EU solutions: general characteristics about the distribution grids (operating voltage levels, load density, size of distribution substations, network architecture) and network users (consumer load profiles, DG penetration per technology), reliability levels, and regulatory framework.

Hence, a comparative assessment will be performed between the values of the most relevant parameters/boundary conditions, i.e. those with a stronger impact on the KPIs, both for the EU countries and the new regions, attending to the SRA rules obtained before. The previous comparisons will allow inferring qualitative indications of the potential impact and suitability of GRID4EU solutions in a different context taking into account technical and regulatory boundary conditions exclusively. The regions selected to carry out this analysis correspond to the State of California in the US and Brazil. The main reasons for the selection of these areas are the following: relevant information is publicly made available by regulators and institutions, reduced language barriers and, particularly, the fact that both regions are active in terms of renewable energy integration and smart grid deployment. Furthermore, this choice was also driven by the fact that the network characteristic and regulatory context of these two regions are noticeably different from the EU countries previously analyzed, thus enabling a wider and more comprehensive SRA analysis.

The specific data regarding distribution network characteristics and regulatory information for both regions, essential to perform the aforementioned comparative study, are provided in sections 3 and 4 respectively. Notwithstanding, for the sake of contextualization and introduction, the main features of the power sector organization and key data for both regions will be described on the ensuing.

## 2.1 The Californian general context

Most of the State of California, and part of the State of Nevada, share a common interconnected electricity market. This Californian electricity market is fully liberalized and it is run by an independent system and market operator, i.e. the California ISO or CAISO. According to FERC data[1], the CAISO system comprises over 60GW of generation installed capacity with a peak demand of around 50GW serving a population of over 30 million. As shown in Figure 1, the generation mix is still largely based on conventional centralized generation, particular large hydro units and especially natural gas, which amounts to around 60% of the power generation in the State. Concerning renewable energies, deployment rates have significantly increased over the last

[1] http://www.ferc.gov/market-oversight/mkt-electric/california/glance.pdf

few years due to the existing promotion policies aiming to achieve ambitious long-term RES and carbon reduction policy goals.

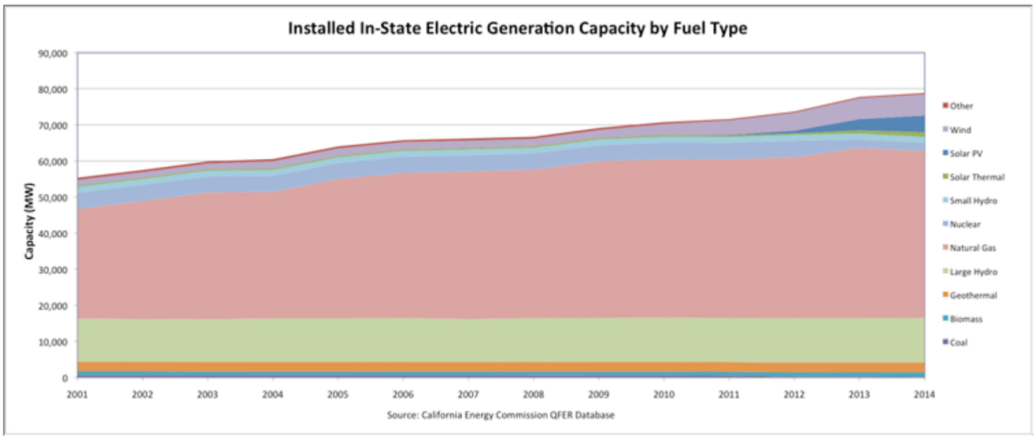



**Figure 1: Power generation capacity per technology in California in the period 2001-2014. Source: California Energy Commission[2]**

The main difference concerning the organization of the power market in the CAISO region, similarly to other ISO regions in the US, as compared to the European approach lies in the degree of separation between the functions of system and market operation. In the CAISO market, both activities are jointly carried out both institutionally and operationally. Thus, system physical constraints are directly incorporated in the market clearing process in such a way that reliability constraints are co-optimized and priced jointly with energy. This process is generally referred to as security-constrained economic dispatch. On the contrary, European systems follow a simpler approach for market clearing which enables this activity to be carried out by purely financial trading platforms named power exchanges, decoupled from system operation responsibilities. A separate agent, namely TSOs, are in charge of performing ex-post corrections to ensure system security as well as to procure the necessary reserves in separate markets.

Another important differential feature of the Californian electricity market is the use of nodal pricing through a detailed representation of the transmission network as well as the existence of a real-time electricity market. This is a spot market used to perform small adjustments to the day-ahead generation scheduling. Trading sessions close 75 min before the start of the trading hour and power plants are dispatched for intervals of between 15 min and 5 min.

The downstream segments of the power supply chain also show important organizational differences with respect to the European context. Power distribution is generally carried out by vertically integrated utilities supplying specific geographic areas. Despite the fact that there are over 50 utilities state-wide, most of these are publicly-owned utilities and cooperative. Only six of them correspond to private utilities or IOUs and are under the supervision of the State's utility regulator, i.e. the California PUC or CPUC. IOUs account for over 70% of the points of connection (around 15 million overall) and supply a similar share of the overall electricity demand in the State. Among these, the three major utilities (PG&E, SCE and SDG&E) put together represent more than 99% of the market share of IOUs in California, as depicted in Figure 2. Hence, the focus of

[2] http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html

distribution regulation is usually placed almost exclusively on these three companies. The service areas of these IOUs are shown in Figure 3.

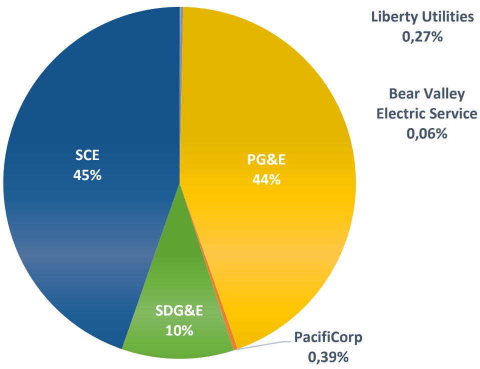



**Figure 2: Share of electricity demand supplied by each IOU in the year 2014. Source: California Energy Commission (California Electricity Data, Facts, & Statistics)**

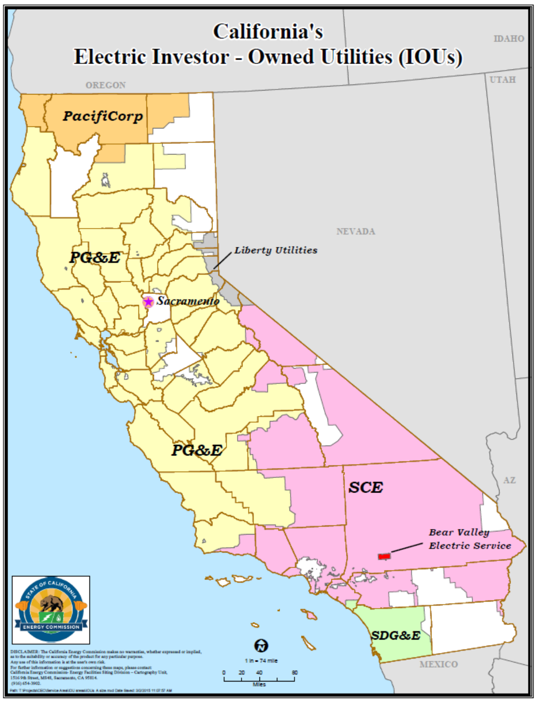



**Figure 3: Service areas of IOUs in California. Source: California Energy Commission[3]**

## 2.2 The Brazilian general context

Brazil has a liberalized and competitive electricity market operated under an ISO model similar to the Californian one, where the ONS makes all the decisions related to the generation economic dispatch and hydrothermal coordination. Nonetheless, ex-post prices and the settlement of economic transactions are duties of a separate entity named the Chamber for Electric Energy Trading (CCEE). This institutional framework mainly derives from a particular feature of the

[3] http://www.energy.ca.gov/maps/serviceareas/CA_Electric_Investor_Owned_Utilities_IOUs.pdf

Brazilian electricity system, which is largely dominated by hydropower. This technology amounts to more than 70% of the total installed capacity, which is around 140GW. The aforementioned generation capacity supplies a peak demand of about 85GW and over 77 million consumers.

Non-hydro RES capacity mainly corresponds to biomass power plants (CHP units) fired by sugarcane, small hydro units and wind power. In spite of the apparently high ratio of installed capacity over peak demand, significant capacity additions are deemed necessary due to the need to face fast load growth (around 4-5% annually) and the intermittency in RES output.

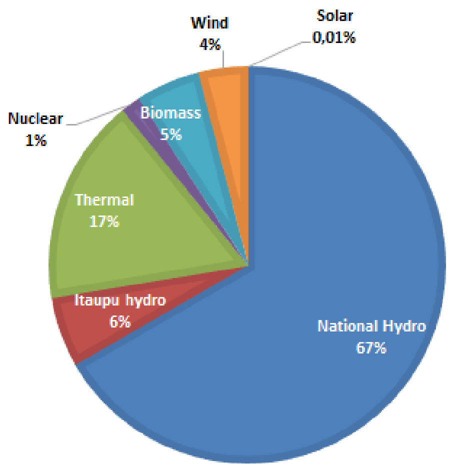



**Figure 4: Installed generation capacity in Brazil by the end of 2014. Source: ONS[4]**

The Brazilian energy market organization significantly differs from that of Europe or California as a result of the aforementioned dominance of hydro power generation. Whereas in the two former regions competitive electricity markets are based on the submission of production bids from generation units, a centralized economic dispatch based on audited costs is performed in the case of Brazil. Thus, hydro units are optimized considering the medium-term cost minimization considering the stochasticity in the water inflows and risk constraints (reliability). The time horizon used to compute spot prices is a weekly period, which contrasts sharply with the more typical day-ahead approach commonly used in Europe, and capacity-constrained power systems in general.

The main reason for this approach is that in a hydro-dominated power system, spot prices would be very low of zero for a significant share of the hours of the year, with price spikes during dry periods, as shown in Figure 5. Moreover, given the abundance of generation dependent on weather behaviour and water inflows, the main challenge in the Brazilian power system is not to supply the peak capacity demand, but to supply the whole energy demand even under dry conditions. Hence, a bid-based generation dispatch may lead to a great price volatility and market power abuse during scarcity periods. In order to prevent both challenges, under such market model, buying agents (distribution companies, suppliers and large consumers) are mandated to sign financial energy contracts (contracts for differences or CfD) with generation units. Spot prices, calculated ex-post on the basis of measured power injections and withdrawals, are then used to settle the differences between contract prices and short-run marginal prices.

[4] http://www.ons.org.br/download/biblioteca_virtual/publicacoes/DADOS2014_ONS/2_3.html

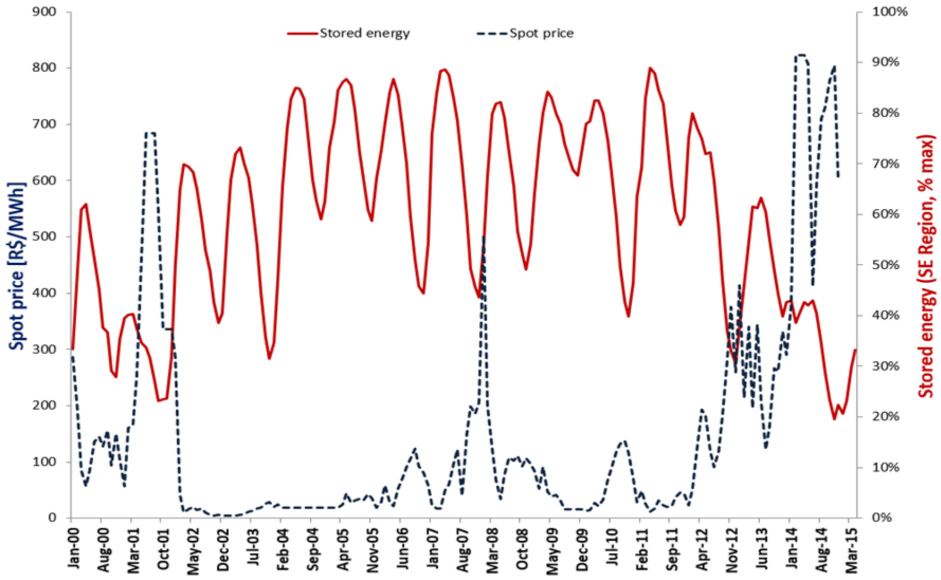



**Figure 5: Spot prices and stored energy in Brazil in the period 2000-2015. Source: (Barroso 2015)**

The organizational model of the downstream segments of the power sector is closer to the Californian approach than to the European one. Distribution companies, in addition to their network-related activities, act as electricity suppliers to regulated consumers, which represent around 75% of the final demand of electricity (the total electricity demand amounted to 500TWH in 2014). The remaining 25% corresponds to the so-called free consumers which directly contract their energy supply with generators, with or without the intermediation of a supplier. Free consumers must have a peak load above 3MW and be connected to a voltage level of 69kV or higher. Overall, there are 63 distribution companies in Brazil, of which the 48 largest supply 98% of the regulated consumers. These largest distribution companies are grouped under the Brazilian Association of Energy Distribution Companies or ABRADEE. Distribution companies are mostly private (47), being the rest of them public companies owned either by municipalities (3), states (8), or the federal government (6). All the sectorial regulation is determined at federal level by the Brazilian Energy Regulatory Authority or ANEEL.

# 3 Technical SRA barriers and drivers

This section evaluates the replicability potential of GRID4EU smart grid solutions to the contexts on California and Brazil from a technical perspective. Thus, the focus will be placed on the technical parameters associated with the distribution networks as well as the network users, mainly DG and end consumers, that may affect the replicability of the use cases under consideration.

In order to do this, the distribution network characteristics in the selected contexts have been firstly described to the extent possible on the basis of the publicly available information. This information is then compared to the technical parameters of the representative networks for EU countries used in previous SRA studies. The results of this comparative assessment is presented in section 3.1. Subsequently, using the previous comparison of technical features and the results of the technical SRA presented in gD3.4 and gD3.5, section 3.2 assesses the replicability potential of GRID4EU use cases for the contexts of California and Brazil.

## 3.1 Distribution networks in California and Brazil vs. the EU context

This section describes, using as much numerical data as posible, the main features of distribution networks in California and Brazil. Information collected comprises network design and structure, operational criteria, DG data, demand response status, continuity of supply levels, network energy losses or ongoing smart grid pilot projects.

### *3.1.1 Distribution networks in California*

Power distribution in California comprises the MV and LV levels located downstream of the transmission system, which typically operates at voltage levels of 66kV or above and are under the supervision of the CAISO. Nonetheless, some network assets operating at between 60kV and 138kV may be owned by distribution utilities and are considered as distribution assets in some cases (KEMA Consulting GmbH 2011). Note that this ambiguous categorization of HV assets into transmission and distribution is similar to the European situation, where subtransmission is operated by DSOs in some countries, whereas they are operated by TSOs in others. On the ensuing, HV or subtransmission networks will not be considered owing to the fact that GRID4EU use cases focus on the MV and LV levels, which are always under the ownership and operation of distribution companies.

The subsequent categorization of Californian MV distribution systems is largely based on an extensive study carried out by the PNNL that developed a taxonomy of 24 prototypical MV feeder models. In order to do this, a clustering analysis was carried out using data for 575 distribution feeders from 17 different utilities all across the US, categorized into five climate regions (Schneider et al. 2008). Overall 24 feeders representing the major characteristics of MV feeders across the US were built. Weighting factors were assigned for each of these feeders so as to enable scaling-up analyses. One of the main parameters used to classify distribution feeders was the voltage level. As shown in Figure 6, the US distribution system is largely dominated by feeders operated at around 12.5kV, followed by a smaller group of feeders operated at around 22-25kV and a few older legacy feeders operated at voltage levels below 5kV.

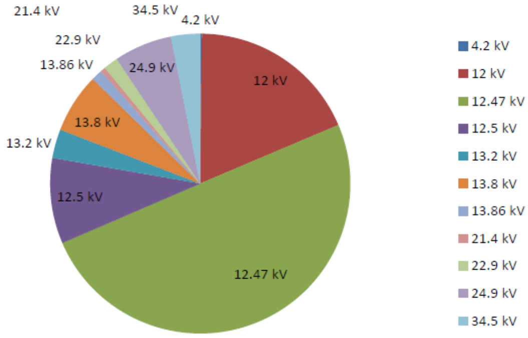



**Figure 6: Operating voltage levels of the 575 distribution feeders evaluated in (Schneider et al. 2008)**

In the specific case of California, the situation is rather similar to the picture depicted in Figure 6. The most common operating voltage level for MV grids is 12.47kV, albeit there are some legacy assets that are still operated at or below 4.8kV. Furthermore, some areas with a very low density of demand may be operated at higher voltage levels to prevent an excessive voltage drop caused by loads located far away from the substations (KEMA Consulting GmbH 2011).

Building on the previous report by the PNNL, (Cohen et al. 2015) created a subset of distribution feeders specific to the State of California by choosing those representative feeders corresponding to the climate regions where California is located: west coast characterized by a temperate climate (R1) and non-coastal south-west characterized by a hot and arid climate. The resulting subset of distribution feeders is shown in Table 2. Since the goal of the aforementioned study was to upscale results about the impact of distributed PV units on the network of PG&E, weighting factors for the different feeders were estimated for this utility. For the sake of a reference, these weights are provided in as well Table 2 (PG&E supplied almost 44% of the state's demand in 2014 and operates the largest distribution area in the State).

| Feeder name | Type of area | Peak load (MW) | Distribution transformers | Average house (kW) | Length (km) | Underground (%) | Voltage regulators | Connected to adjacent feeders | Weight (PG&E area) |
|---|---|---|---|---|---|---|---|---|---|
| R1-12.47-1 | moderately populated suburban and rural area | 7,15 | 618 | 4 | 5,5 | 40% | 0 | Yes | 8% |
| R1-12.47-2 | moderately populated suburban-lightly populated rural area | 2,83 | 264 | 4,5 | 10,3 | 30% | 0 | No | 9% |
| R1-12.47-3 | moderately populated urban area | 1,35 | 22 | 8 | 1,9 | 15% | 0 | Yes | 8% |
| R1-12.47-4 | heavily populated suburban area | 5,3 | 50 | 4 | 2,3 | 100% | 0 | Yes | 7% |
| R1-25.00-1 | lightly populated rural area | 2,1 | 115 | 6 | 52,5 | 40% | 1 | No | 4% |
| R3-12.47-1 | heavily populated urban area | 8,4 | 472 | 12 | 4 | 75% | 0 | Yes | 24% |
| R3-12.47-2 | moderately populated urban area | 4,3 | 62 | 14 | 5,7 | 67% | 0 | Yes | 24% |
| R3-12.47-3 | heavily populated suburban area | 7,8 | 1733 | 4 | 10,4 | 25% | 1 | Limited | 16% |

**Table 2: Summary data for representative distribution feeders for California. Data drawn from (Cohen et al. 2015) and (Schneider et al. 2008)**

Comparing the information in the previous table with the data for the representative networks built within the GRID4EU project, significant differences may be observed. Despite the fact that MV voltage levels are relatively similar (albeit several EU countries tend to have higher voltage levels, i.e. typically at 20kV) and the average length of MV feeders is comparable in both contexts, undergrounding levels tend to be lower in California, where overhead poles are common even in urban areas. Nonetheless, the most significant differences between California, and the US as a whole, and the EU presumably lie in the topological design of the distribution grid (see Figure 7).

In California, contrary to European countries, distribution utilities resort to MV networks to get very close to end consumers, at the expense of shorter LV networks. In order to do this, it is common to use a balanced three-phase systems in the main trunks downstream of HV/MV substations and then switch to use single-phase or two-phase systems in lateral branches (see Figure 7). Fuses are oftentimes used for protection purposes at the head of these lateral branches. Distribution transformers are generally located at these lateral branches and, as discussed below, present important differences with respect to the secondary substations used in the EU. As a result of this differential configuration, distribution networks in California require a much higher number of distribution transformers in order to supply a demand per feeder of the same order of magnitude.

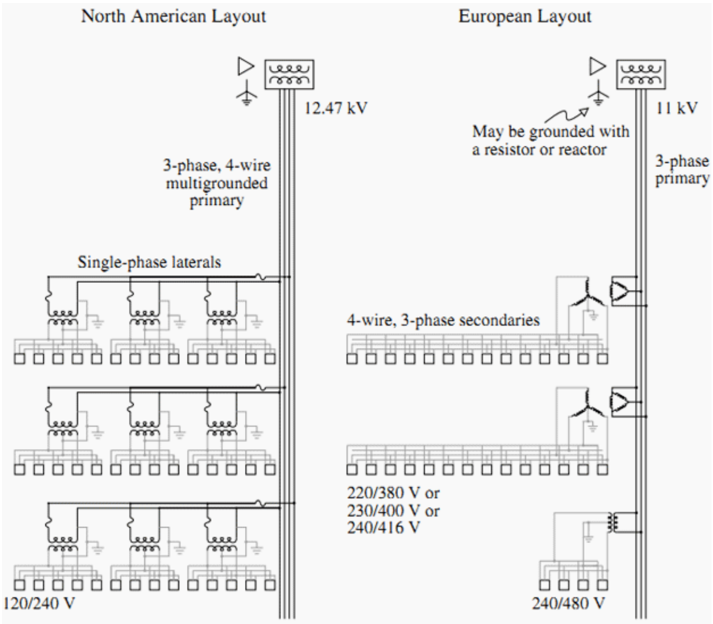



**Figure 7: Comparison of distribution network layout in North-America and Europe. Source: Electrical Engineering Portal[5]**

MV networks are operated in a radial configuration both in urban and rural areas, similarly to European DSOs. Moreover, as shown in Table 2, MV feeders are normally interconnected with several adjacent feeders through NO switches so as to provide alternative sources of supply in case of a fault, except in lightly populated rural areas. Nevertheless, the necessary switchgear is not located at the secondary substations as it is normally the case in Europe. This equipment is usually located throughout the MV feeders either pole-mounted (overhead lines) or pad-mounted (underground cables). MV feeders present several resources for voltage control. In addition to the OLTC (at the distribution substations) and capacitor banks that are also used by European DSOs, voltage regulators (autotransformers) are widespread, particularly in lightly loaded long feeders (Kersting 1991; Schneider et al. 2008; Arritt and Dugan 2010; Schneider and Fuller 2010).

[5] http://electrical-engineering-portal.com/north-american-versus-european-distribution-systems

As a result of the previous topological differences in the design of MV networks, the characteristics of LV distribution presents deep differences in California with respect to the European case. Single-phase distribution transformers typically have a size in the interval of 25-50kVA and supply a low number of end consumers[6], which does not normally exceed 20 and, in sparsely populated rural areas, may not be more than one. The resulting LV system, usually referred to as secondary system, is much shorter as it only needs to supply the few consumers located close to the transformer. In contrast, European secondary substations are equipped with three-phase transformers with capacities within the range of 250-1000kVA (being standard the use of 400kVA and 630kVA transformers). Each one of these substations typically supplies several tens or hundreds of consumers. One last important difference in the LV system consists in the standard voltage level, which is 120V (phase-to-neutral) in California and around the double, 220-240V, in Europe.

In California, the voltage at the point of connection of residential consumers must remain between the nominal value and a maximum variation of 5% below the nominal value. In some particular cases, and for commercial and agricultural consumers, an overvoltage of up to 5% above the nominal voltage is allowed, as defined in the electric Rule nº 2[7] and (ANSI 2011). The National Electrical Code (NEC) allows up to a 5% drop – up to 3% drop in the main feeder and an additional <3% in individual branch circuits.

Another important technical parameter regarding the replicability of GRID4EU use cases is the distribution reliability levels. In California, this is measured through three indices: SAIDI, SAIFI and MAIFI. As it will be described in section 4.1, the CPUC periodically sets annual reporting obligations and incentive mechanisms to encourage IOUs to improve reliability levels. Given the high number of distribution utilities in California and the fact that a small share of them are under the supervision of the CPUC, aggregate statistics for these indices could not be found. For the sake of illustration and broad-level comparison with EU DSOs, historical values of the reliability indices for three IOUs (PG&E, PacifiCorp and SDG&E respectively) are shown in Figure 8, Figure 9 and Figure 10.

[6] In the case of some large consumers such as offices of shopping centres in urban areas, three-phase LV networks may be used. However, this is more of an exception than the rule. In Europe, these consumers would oftentimes be connected directly at MV.

[7] https://www.sce.com/NR/sc3/tm2/pdf/Rule2.pdf
http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_2.pdf

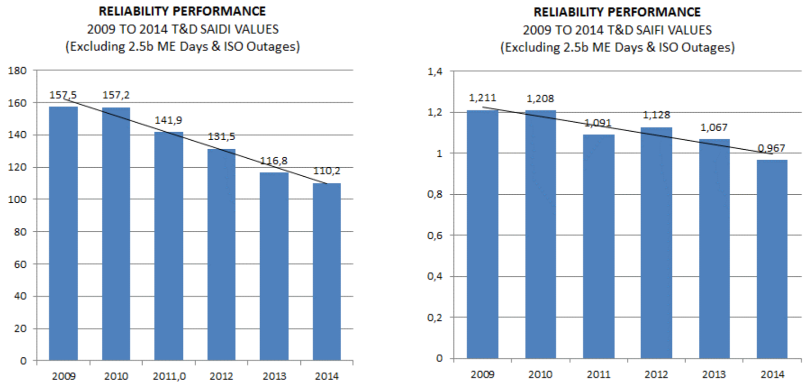



**Figure 8: Reliability indices corresponding to the PG&E utility area in California in the period 2009-2014. Source: (PG&E 2015)**

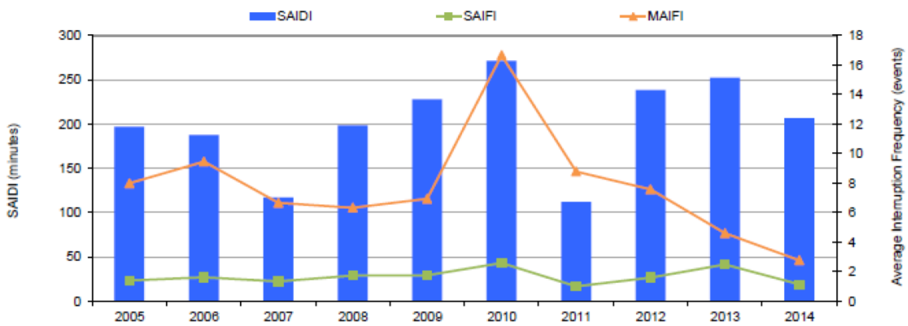



**Figure 9: Reliability indices corresponding to the PacifiCorp utility areas in California in the period 2005-2014 (excluding major events). Source: (PacifiCorp 2015)**

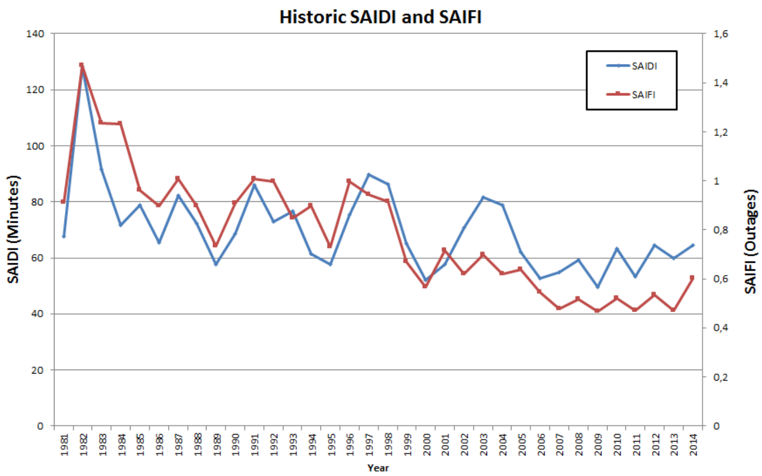



**Figure 10: Reliability indices corresponding to the SDG&E utility area in California in the period 1981-2014. Source: (SDG&E 2015)**

Comparing these values with the data for European DSOs reported in (CEER 2012; CEER 2013), it can be seen that PG&E could be considered to be in the upper tiers for typical European countries (excluding abnormally high values in some countries) whereas SDG&E would be closer to the best-performing countries (see Figure 11). In the case of PacifiCorp, the reliability levels would be considered well below the average as compared to European countries[8]. As discussed in gD3.2/gD3.3, within GRID4EU countries, Germany presents the highest reliability levels whereas the remaining countries show SAIFI levels between 0.8-1.8 and SAIDI values in the range of 50-100min in GRID4EU countries[9]. When comparing these data, it is important to bear in mind that values of not directly equivalent given the different definition of sustained interruptions. In California, these are those exceeding 5min, whereas in Europe this threshold is usually of 3min[10].

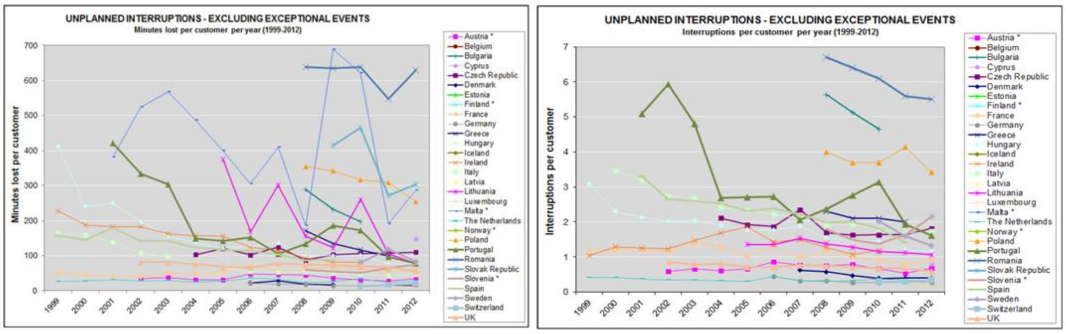



**Figure 11: SAIDI and SAIFI in European countries in the period 1999-2012 (unplanned interruptions excluding exceptional events). Source: (CEER 2013)**

Distribution network losses was considered as a relevant KPI for several of the GRID4EU use cases, particularly those related to DER integration in MV and LV supervision. In developed countries, network losses mostly correspond to technical losses and the share of total T&D losses rarely exceeds a value of 10-15% of total electricity generation, being distribution losses accountable for typically around 70-85% of total losses. This is the case of most EU countries as reported for the year 2006 in (ERGEG 2008). As shown in Figure 12, despite the fact that values reported are not directly comparable due to differences in the calculation formulas, T&D losses in California seem to fall within a similar range as EU countries. Therefore, it is sensible to assume that commercial losses are not a major concern for utilities as it may be in other contexts (see the case of Brazil below).

8 SAIDI values are particularly high in comparison. Moreover, the observed values show a significant variability throughout the years. Potential reasons for this comprise the characteristics of the distribution area of this utility, mainly its small size and mountainous areas.

9 Unplanned interruptions excluding exceptional events.

10 This difference in the definition of long interruptions would imply that, particularly for the case of SAIFI, measured reliability levels would be better under the Californian approach for the same level of network faults.

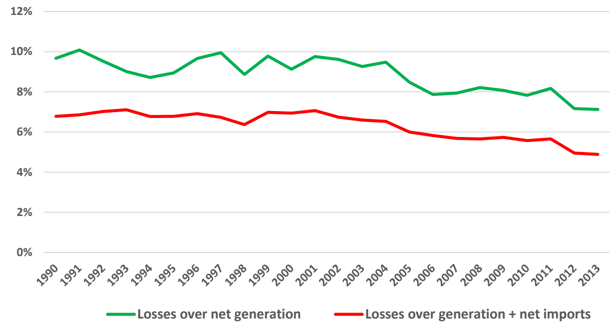



**Figure 12: T&D losses in California in the period 1990-2013. Source: Own elaboration with data from the US Energy Information Administration[11]**

In addition to the aforementioned performance metrics, the deployment rate of smart meters and AMI is a key factor determining the international replicability or some GRID4EU use cases. AMI deployment plans had been approved in most EU countries driven by the mandate included in the Electricity Directive, being the DSO the agent most commonly in charge of this roll-out. Nonetheless, several exceptions could be found where a large-scale deployment was not still approved due to negative or inconclusive CBA or where the responsibilities were not fully clear (European Commission 2014a; European Commission 2014b; European Commission 2014c). The situation in California is rather positive in this regard since 12.4 million smart meters (out of approx. 13.2 connection points) have been deployed state-wide by the three major IOUs within the period 2006-2013. The exact deployment figures per metering technology and sector are provided in Table 3.

| Technology by sector | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|
| **AMR meters** | **181.180** | **238.634** | **345.864** | **1.696.965** | **431.858** | **580.957** | **827.670** |
| Residential | 167.236 | 221.857 | 278.976 | 1.520.278 | 319.842 | 481.305 | 699.209 |
| Commercial | 12.701 | 15.597 | 57.736 | 164.498 | 97.104 | 90.939 | 115.318 |
| Industrial | 1.241 | 1.178 | 9.152 | 12.189 | 14.912 | 8.699 | 13.070 |
| Transportation | 2 | 2 | 0 | 0 | 0 | 14 | 73 |
| **AMI meters** | **140.042** | **363.353** | **2.636.757** | **4.036.383** | **10.610.811** | **10.580.445** | **12.427.747** |
| Residential | 130.261 | 341.772 | 2.423.941 | 3.683.560 | 9.495.329 | 9.469.164 | 11.012.738 |
| Commercial | 9.232 | 21.069 | 211.167 | 350.663 | 1.075.557 | 1.082.629 | 1.358.473 |
| Industrial | 548 | 509 | 1.649 | 2.129 | 39.922 | 28.621 | 56.453 |
| Transportation | 1 | 3 | 0 | 31 | 3 | 31 | 83 |

**Table 3: Smart meter deployment in California in the period 2007-2013. Source: US Energy Information Administration**

Last but not least, evaluating the replicability of GRID4EU smart grid solution in the case of California requires characterizing the situation of DG in the state. The reason for this is that the main goal of several of these uses cases is precisely to enable a more efficient integration of DG, potentially deferring or avoiding grid reinforcements. Within the US, California is a frontrunner in the promotion of RES-based electricity production through a variety of support mechanisms that will be described in section 4.1, particularly in the case of solar energy. Statistics on installed capacity per voltage level at the point of connection could not be found. Hence, an approximation based on the size of the power plants has been made so as to quantify the amount of DG capacity found in California.

[11] http://www.eia.gov/electricity/state/california/

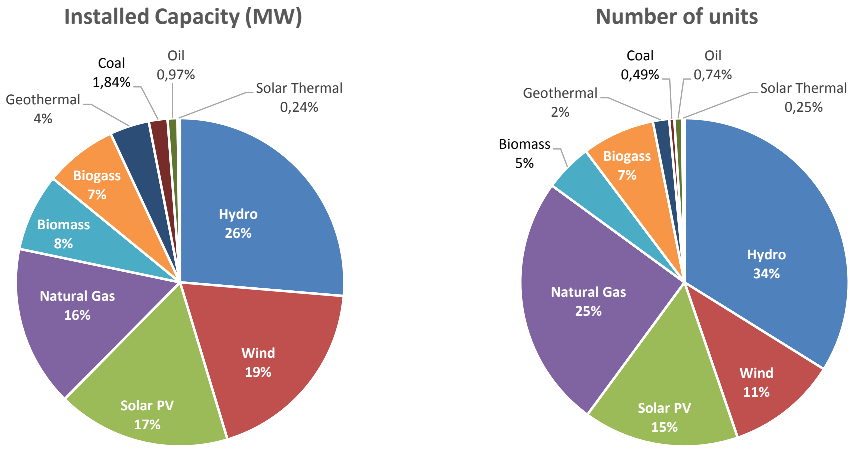



**Figure 13: Share of installed capacity and number of units of plants between 0.1-20MW (estimated MV DG). Source: Own elaboration with data from the California Energy Commission**

Using data from the California Energy Commission, the amount of DG connected to the MV grid has been estimated by assuming that all generation operational units between 0.1MW and 20MW are connected at MV level[12]. This results in approximately 4.13GW of DG connected to the MV level which represents around 5.3% of total installed generation capacity in the state according to the same source. This degree of penetration can be considered rather low when compared to some of the leading EU countries in terms of DG capacity such as Germany, Italy or Spain. As shown in Figure 13, most of this DG capacity would correspond to small hydro, wind, solar PV and natural gas (mostly CHP) generation. Among these, wind presents the largest average unit size (roughly 9MW), whereas natural gas and hydro present the smallest one (around 3-4MW per unit).

The DG capacity connected to the LV grid can be considered to be mostly solar PV units installed on rooftops. California is one of the major markets in the US for such installations thanks to the continuous policy support in the form of net-metering and investment subsidies. Detailed information on the capacity deployment and corresponding costs of such installations is provided by the *Go Solar California* initiative[13]. According to this source, up to 3656 MW of distributed PV had been installed as of January 2016 across all sectors (residential, commercial, non-profit and governmental). The corresponding average unit size is of 7.8kW. Notwithstanding, using data about installed capacity and number of applications for the CSI program, the average size of PV installations in non-residential sectors are typically around 100-300kW, whereas residential installations lie around 5kW. Adding this LV-connected capacity to the previously estimated for MV-connected DG, the share of DG over total installed generation capacity in California would be of almost 10%.

12 The threshold of 20MW may lead to an overestimation of the amount of DG. For instance, some European countries limit the size of MV (below 30kV) generators to around 10MW. Nonetheless, this was deemed a reasonable approximation for a broad-level analysis.

13 This is a joint initiative of the California Energy Commission and the CPUC to promote the deployment of solar PV installations. Further info at: http://www.gosolarcalifornia.ca.gov/

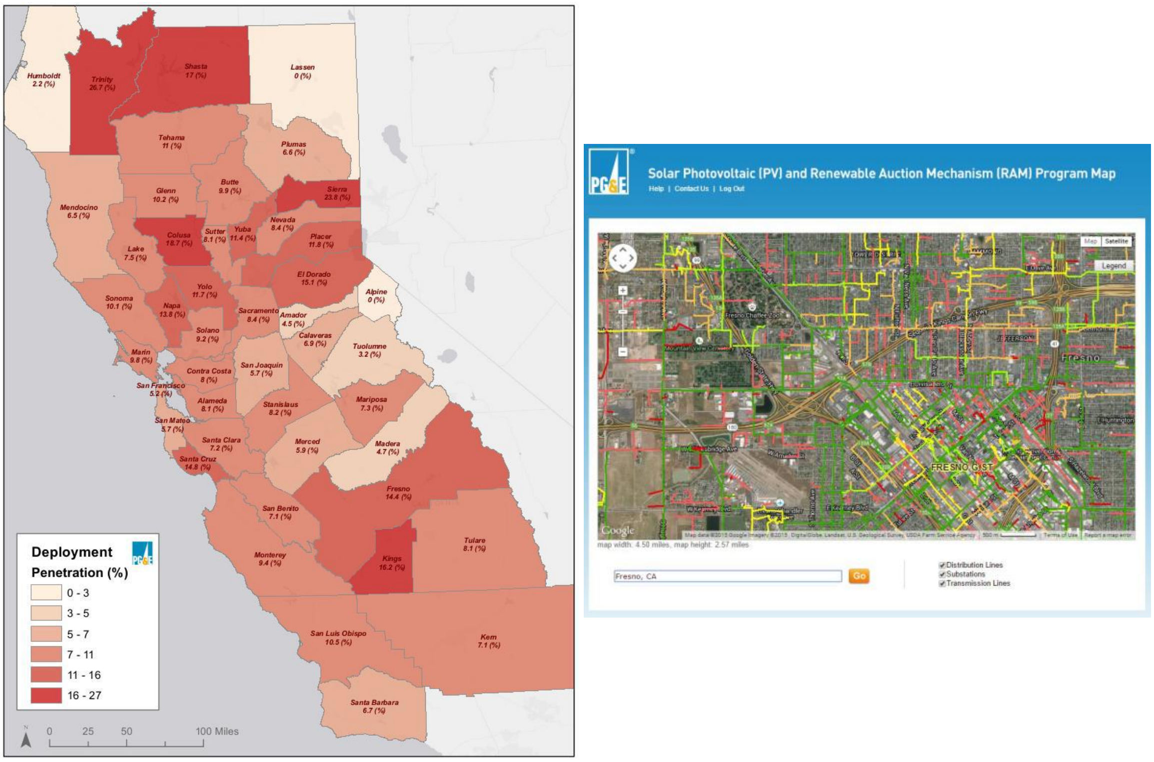



**Figure 14: Example of the results from the integration capacity analysis carried out for DRPs: (a) currently deployed DG with respect to peak demand in PG&E distribution networks by county and (b) screenshot of the map of integration capacity of MV feeders in PG&E distribution networks**

In order to promote DER integration and to understand the required investment, DSOs have been mandated[14] to elaborate the so-called Distribution Resource Plans (DRPs). DRPs must comprise the following analyses: (1) Integration Capacity Analysis; (2) Optimal Location Benefit Analysis; and (3) DER Growth Scenarios, to assess the network hosting capacity and the impact of the integration of the different types of DER expected in their distribution areas. DRPs were submitted by DSOs in July 2015 and are already published[15]. The analyses have been carried out for the actual networks or for a set of several representative networks obtained through clustering of all actual feeders, and the results published have a very high level of granularity, including the integration capacity on a feeder by feeder, substation by substation and county by county basis. Figure 14 shows a couple of examples of the results obtained by PG&E. In general, and at an aggregated level, the current level of DER penetration does not surpass demand and no overvoltage or overloading problems have been detected. DSOs have only reported potential overloading problems at specific substations where the installed DG capacity exceeds the computed integration capacity (for instance, this is the case for less than 30 out of over 700 substations for PG&E).

[14] California Legislature in Assembly Bill (AB) 327, Public Utilities Code 769.
[15] http://www.cpuc.ca.gov/General.aspx?id=5071

### 3.1.2 Distribution networks in Brazil

Distribution companies in Brazil own and operate the electricity networks with rated voltages below 230kV, comprising the subtransmission grid (69-138kV), primary distribution or MV (2.3-44kV) and secondary distribution or LV (110-440V). Thus, as it occurred in the case of California as well as several European countries, distribution companies own and operate the HV network too. Notwithstanding, for the same reasons previously stated, the focus will be placed on the MV and LV levels hereinafter.

The most typical operating voltage for the MV level is 13.8kV, albeit networks operated at 23.1kV, 11.4kV or 2.3 kV may be found. Undergrounding levels in Brazil are very low, being common to see overhead lines on poles even in urban areas. For instance, based on data from 49 distribution companies in Brazil in the period 1998-2003, (Silva 2011) reports average shares of undergrounding around a value of 0.6%, which remained constant throughout that period. The distribution companies evaluated in this study presented shares of MV undergrounding within an interval of 0-14%. The reason for such low values is that underground networks are used exclusively in very densely populated areas or in protected areas where regulation mandates it due to environmental or aesthetic reasons. Insulated overhead feeders may be used to reduce the space between phases.

The overall architectural design of Brazilian distribution networks presents characteristics from both the Californian and European approaches described in the previous section. Nevertheless, one of the main differential aspects faced by Brazilian distribution companies is that, as reported by (Mota 2004), demand dispersion in Brazil is much larger in the US due to the comparatively larger consumption of individual consumers as well as the geographical features of the countries. Consequently, and especially in some regions (e.g. North-West), Brazilian distribution companies need to deploy a very long network for the same number of consumers.

MV grids are operated radially as in the rest of contexts considered in this report. However, the design of MV grids may be meshed. According to (Lima et al. 2002), rural areas with low load density have radial MV feeders whereas urban areas present significant interconnections among neighbouring feeders. An example of an urban MV network that may be found in a densely populated area in Brazil is provided in Figure 15. This particular network presents 17 automation points in 4 feeders that add up to 72km in length and supply 450 distribution transformers and around 10000 consumers. It is noteworthy that switchgear is not located at the secondary substations as in European countries, but throughout the network poles as it was the case in California.

Alternative configurations for the MV grid in areas with an intermediate load density may include two feeders connected at the end through a NO switch (supported substations) or a ring configuration. Furthermore, in some rural areas with a dispersed load, single-phase MV distribution is used to supply single-phase loads. This is achieved by sending each outgoing feeder-phase in a different direction so that each phase follows a different layout.

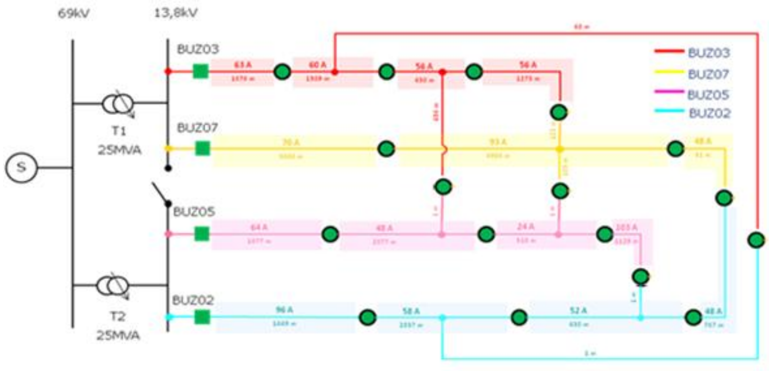



**Figure 15: Single-line diagram of the MV grid where automation has been implemented under the pilot project "Cidade Inteligente Búzios". Source: (Ampla 2014)**

The rated transformation capacities of distribution substations (most commonly 138/13.8kV or 69/13.8kV) is typically 25MVA or 2x25MVA in densely populated areas. On the other hand, smaller substations are installed in areas with a more dispersed population. The number of outgoing feeders of a substation generally ranges between 4 and 8. The previous statement about the size of distribution substations can be supported by Table 4, which compares data for the year 2005 from three distribution companies which are part of the CPFL group and supply different areas. More specifically, average sizes or substations and MV/LV transformers have been computed from data provided in (CPFL 2006). Moreover, several measures of load density have been obtained. These distribution companies supply between 1 and 3 million consumers each.

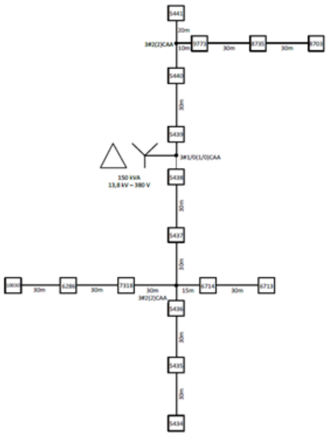
| Distribution company | Substations | | | Distribution transformers | | | Load density | | |
|---|---|---|---|---|---|---|---|---|---|
| | Number | Capacity (MVA) | Average (MVA) | Number | Capacity (MVA) | Average (kVA) | Cons. per network km | Distr. Transf. per Subst. | Cons. per Distr. Transf. |
| **CPFL Paulista** | 246 | 6622 | 26,9 | 97652 | 4661 | 47,7 | 43,3 | 397,0 | 33,3 |
| **CPFL Piratininga** | 41 | 2436 | 59,4 | 31351 | 2241 | 71,5 | 62,8 | 764,7 | 40,3 |
| **RGE** | 59 | 1250 | 21,2 | 52356 | 1678 | 32,0 | 14,6 | 887,4 | 20,9 |

**Table 4: Substations and transformer statistics for the distribution companies belonging to the CPFL group. Source: (CPFL 2006)**

In order to control bus voltages in the MV grid, distribution companies make extensive use of voltage regulators and capacitor banks dispersed throughout the grid (pole mounted) as well as OLTC in the primary substations. Moreover, due to the high share of overhead networks, reclosers are a very important element of Brazilian distribution grids so as to enhance the resiliency of the grid against temporary faults.

Moving on to the LV network, the characteristics of distribution transformers can be seen as a combination of European and Californian features. On the one hand, three-phase transformers are normally used (as in Europe), most commonly with a ratio of 13.8kV/380V or 13.8kV/220V. Nonetheless, these transformers are almost exclusively pole-mounted and present sizes from 25kVA to 150kVA, thus being closer to the typical values in California. Because of this, the LV networks are shorter than in Europe being the distance between consumers generally lower than 30 meters (Santos et al. 2014). A particular feature of the Brazilian system is that the LV rated values may differ on a municipality basis, thus being sometimes necessary to use converters/adapters when moving within the country. Another particularity is that LV networks are almost fully overhead and LV lines frequently share poles with MV lines, being the former placed in a lower position on the poles.

As mentioned above, contrary to the case of California, three-phase LV systems are widespread, supplying single-phase, two-phase and three-phase consumers. An illustrative test network constructed from real data from a distribution company in an urban area is shown in Figure 16.



| | |
|---|---|
| **Transformation capacity** | 150 kVA |
| **Voltage conversion** | 13,8/0,38 kV |
| **Number of phases** | 3 |
| **Number of consumers** | 110 |
| **Total length** | 375 m |

**Figure 16: Brazilian test LV system. Source: (Santos et al. 2014)**

Continuity of supply is monitored using two main indicators named DEC and FEC, which are broadly equivalent to SAIDI and SAIFI respectively. Long interruptions are considered to be those longer than 3min, as in the European context (ANEEL 2016b). Figure 17 shows that, despite the fact that a significant reduction in the frequency and duration of interruptions has been achieved over the last two decades, these values of reliability indices are still significantly higher than the ones observed for European countries or California presented in section 4.1.

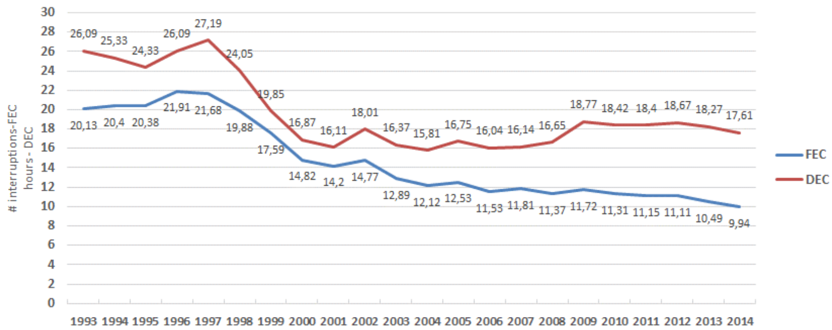



**Figure 17: Evolution of distribution reliability indices in Brazil in the period 1993-2014. Source: Own elaboration with data from ANEEL and ABRADEE**

Nonetheless, the size of this country as well as its geographical characteristics introduce an important heterogeneity across distribution areas. As a result, great differences may be found when comparing different distribution companies among them. This is clearly illustrated by Figure 18 which shows the reliability indices recorded for several distribution companies as well for the overall country. It can be seen that the two distribution companies operating areas in the northern interior are (Amazonia) present much worse indices, well above the country average, than those companies operating areas in the south-east region of the country (close to Rio de Janeiro).

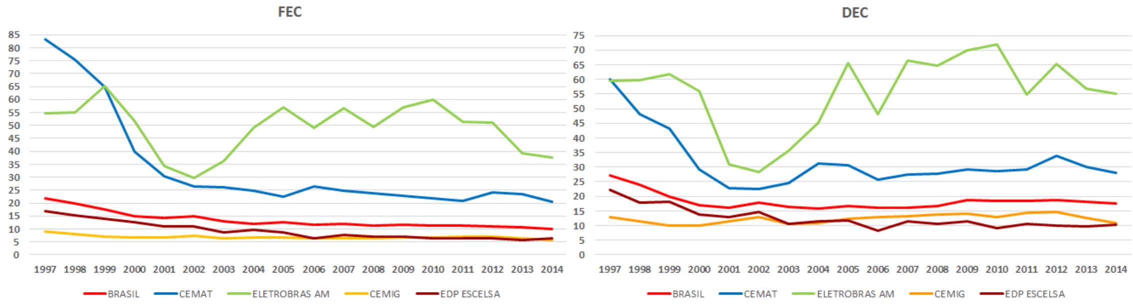



**Figure 18: Evolution of distribution reliability indices in Brazil in the period 1993-2014. Comparison among distribution companies Source: Own elaboration with data from ANEEL and ABRADEE**

A particular feature of Brazilian distribution grids as compared to California or GRID4EU countries, is that the level of losses is notably higher. As shown in Figure 19 (right), overall distribution losses over the last decade have remained relatively stable within a range of 13-14% of the energy injected into the distribution system. This difference can be largely attributed to the commercial losses, which account for approximately 40% of total distribution losses. The aforementioned figure shows that this situation has remained stable for the last 10 years. According to calculations from the regulator, the cost of commercial losses can be estimated to be at about 3.8 million Brazilian real per year (approx. 860 million €)[16]. Another relevant feature which is shown by Figure 19 (left) is that the comparative level of losses across distribution companies presents a remarkable variability, ranging from 5-6% up to almost 40% of the electricity injected. In many cases, some of the distribution companies with the highest levels of losses also present high levels of non-technical losses (see footnote 16).

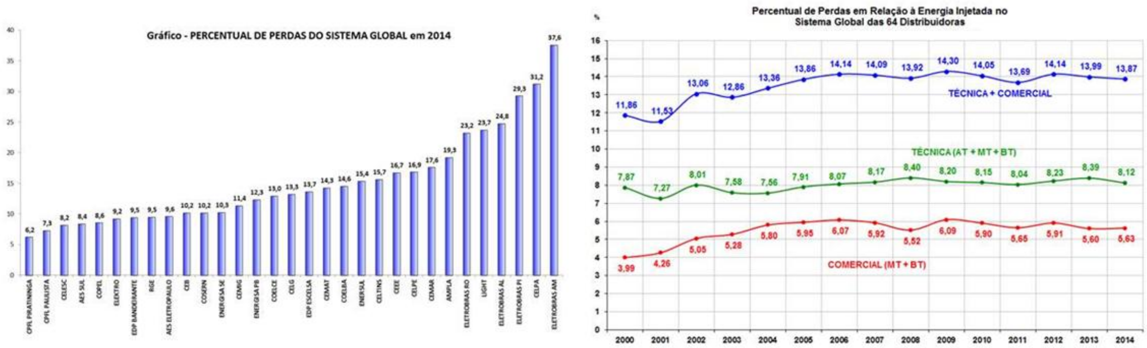



**Figure 19: Share of distribution losses per company in 2014 (left) and evolution of distribution losses in the period 2000-2014 broken down per origin. Source: ABRADEE[17]**

The energy regulator, ANEEL, has defined a clear deployment model as well as technical requirements for smart metering systems (see section 4.2 for further details on the regulatory issues). Despite some optimistic initial estimates, the expected penetration of smart meters is significantly lower than initially foreseen due to regulatory changes and delays in the adaptation process. Some experts report that deployment estimations have dropped from 60 million smart

---

[16] http://www.aneel.gov.br/arquivos/Excel/Base_Perdas_Internetnov2015_19-11.xlsx
[17] http://www.abradee.com.br/setor-de-distribuicao/perdas/furto-e-fraude-de-energia

meters rolled-out by 2020 to 27 million in 2030[18]. In order to interpret these numbers, it is necessary to know that there are more than 77 million distribution consumers in Brazil, including over 65 million residential consumers (ABRADEE 2015).

Besides the previous estimations, the actual deployment is mainly driven by pilot projects supported by the energy regulator. Table 3 provides further details on the pilot projects testing AMI and AMR technologies as well as planned deployment figures. Overall, most of these projects are relatively small-sized, adding up to a little more than half a million smart meters with one project account for 75% of that. Final figures may vary since several of these projects are still ongoing. In any case, the current penetration of advanced metering technologies in Brazil is still incipient as compared to many GRID4EU countries (e.g. Italy or Sweden) or California, which have reached a complete or almost complete roll-out of smart metering.

| Distribution Company | Project-City name | State | Smart Meters installed (planned) |
|---|---|---|---|
| CEMIG | Cidades do Futuro | Minas Gerais | 4200 |
| Ampla | Cidade Inteligente Búzios | Rio de Janeiro | 10000 |
| Light | Smart Grid Light | Rio de Janeiro | 400000 |
| Eletrobras Amazonas | Parintins | Amazonas | 14500 |
| Eletropaulo | Programa Smart Grid - Eletropaulo Digital | São Paulo | 84000 |
| EDP Bandeirante | InovCity | São Paulo | 13500 |
| Copel | Paraná Smart Grid | Paraná | 10000 |
| CELPE | Arquipélago de Fernando de Noranha | Pernambuco | 800 |

**Figure 20: Planned smart meter deployment in pilot smart grid projects in Brazil. Source: Own elaboration with data from the Brazilian Smart Grid Programme[19]**

The Brazilian regulation uses the term microgeneration to refer to generation plants of no more than 100kW and mini-generation as installations with a rated capacity between 100kW and 1MW (ANEEL 2012b). A complete registry of these units exist given their entitlement to specific support policies. The updated information can be retrieved from ANEEL's webpage[20]. As of January 2016, as displayed in Table 5, there were approximately 11.2MW corresponding to a few more than a thousand micro and mini-generators in Brazil. The vast majority of this generation corresponds to solar PV installations connected both to the LV and MV grid. Comparing these figures with those of California, which has in place similar net-metering policies for these small-sized generators, it can be seen that this sector is still poorly developed in Brazil, particularly considering the size of its power system.

[18] https://www.greentechmedia.com/articles/read/report-brazils-smart-meter-market-drops-from-60m-by-2020-to-27m-by-2030
[19] http://redesinteligentesbrasil.org.br
[20] http://www.aneel.gov.br/scg/rcgMicro.asp

| | Units | | | Installed Capacity (kW) | | |
|---|---|---|---|---|---|---|
| | LV | MV | Total | LV | MV | Total |
| **PV** | 986 | 39 | 1025 | 2205 | 7795 | 10000 |
| **Wind** | 40 | 5 | 45 | 146 | 17 | 163 |
| **Hybrid PV-Wind** | 3 | 2 | 5 | 8 | 5 | 13 |
| **Biogass** | 2 | 1 | 3 | 115 | 162 | 277 |
| **Hydro** | 0 | 1 | 1 | 0 | 825 | 825 |
| **Total** | **1031** | **48** | **1079** | **2474** | **8804** | **11278** |

**Table 5: Micro and mini generation in Brazil (January 2016). Source: Own elaboration. Data from ANEEL**

Notwithstanding, micro and mini-generation are not enough to fully characterize the situation of DG in Brazil. The generation data base from ANEEL[21] does not provide detailed information on the voltage level at which the different generation units are connected to. Therefore, a similar estimation done for the case of California will be performed, on the basis of the unit size of generation installations, so as to estimate the amount of DG connected above LV. In fact, (Brito et al. 2015), relying on information from the aforementioned database, quantifies such DG in Brazil as of April 2015 by setting the threshold for DG at a value of 30MW. The total installed capacity of DG according to this estimation is approximately 16GW, which accounts for 11% of total generation capacity in Brazil. Most of this capacity corresponds to small hydro units, wind farms and biomass power plants.

However, most of this capacity (approx. 65%) lies within the band of 10-30MW which to a certain extent could be presumably connected to the HV network. In fact, the average size of the generators within this range is above 22MW (higher than the threshold assumed for the case of California). Therefore, the actual amount of DG connected to the MV level may be reasonably considered to be lower than that of certain GRID4EU countries such as Germany, Spain of Italy (see section 4.2 for further details on the criteria related to DG size and voltage level connection). Considering only generators no larger than 10MW, the share of DG over total generation capacity would be of just 3.8%. Within this size range, wind would lose weight, being the most technologies small hydro, biomass and non-gas-fired thermal units.

[21] http://www.aneel.gov.br/area.cfm?idArea=15&idPerfil=2

| Technology | Size Range | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 1-5 MW | | 5-10 MW | | 10-30 MW | | Total | |
| | Number of units | Installed Capacity (MW) | Number of units | Installed Capacity (MW) | Number of units | Installed Capacity (MW) | Number of units | Installed Capacity (MW) |
| Small hydro | 187 | 1908 | 71 | 993 | 173 | 3595 | 431 | 6496 |
| Wind | 26 | 108 | 12 | 99 | 158 | 3929 | 196 | 4136 |
| Solar PV | 6 | 14 | 0 | 0 | 0 | 0 | 6 | 14 |
| Biomass | 152 | 654 | 47 | 450 | 96 | 2211 | 295 | 3315 |
| Natural Gas | 54 | 153 | 9 | 59 | 5 | 74 | 68 | 286 |
| Other fossil fuels | 315 | 732 | 28 | 266 | 33 | 526 | 376 | 1524 |
| CHP - Biomass | 0 | 0 | 0 | 0 | 5 | 114 | 5 | 114 |
| CHP - Natural Gas | 17 | 56 | 10 | 75 | 5 | 64 | 32 | 195 |
| CHP- Other fossil fuels | 5 | 12 | 2 | 12 | 2 | 41 | 9 | 65 |
| Total | 762 | 3637 | 179 | 1954 | 477 | 10554 | 1418 | 16145 |

Table 6: Estimated installed DG capacity in MV in Brazil as of April 2015. Source: (Brito et al. 2015)

## 3.2 Applicability of technical SRA results to California and Brazil

### 3.2.1 Demand response

In the last decade both California and Brazil have faced critical electricity situations, which activated in 2002 the demand response programs in those regions. Table 7 summarizes the actions that California and Brazil took to deal with the power crisis. Indeed, some countries have already adopted the Brazilian crisis management scheme to rationalize electricity under long scarcity situations.

| | California (1) | Brazil (2) |
|---|---|---|
| **Shocks** | Supply and Demand | Supply |
| **Shortage** | Capacity (Energy) | Energy only |
| **Action** | 20/20 | Cap (and Trade) |
| **Mandate** | Voluntary | Compulsory |
| **Load Shedding?** | Some | No |
| **Duration** | 11/00 - 05/01 | 6/01 - 02/02 |
| **Government Action** | Slow | Fast |
| **Cost of Demand Response** | US$276/kW-yr | US$7/MWh |
| **Second Best** | US$55/KW-yr (peaking) or shedding | US$150/MWh or shedding (US$300/MWh) |
| **Metering Deployment** | No | No |

Table 7: Demand response actions to deal the power crisis. Source: (Maurer 2009)

Although the Brazilian system is quite flexible from a system perspective, thanks to a high hydro-dominated generation capacity, several challenges are still unsolved: scarcity of energy during drought periods (e.g. “El Niño”), high increase of electrification in urban areas due to the rising of middle class, high levels of technical losses, limitation to build new hydro plants due to environmental concerns. Recently the Brazilian government said it will cost customers US $5.4 billion to recover the cost of buying expensive thermal power on the spot market to replace depleted hydro reserves during the summer heatwave. Indeed, utilities had the biggest losses during the hottest and highest-demand periods of the day.

In order to deal with this situation, Brazil has designed a "Tarifa Branca" [22] to encourage LV consumers to buy electricity when it is cheapest, reducing demand during peak periods. This is a static ToU tariff offered as an opt-in alternative. A schematic representation of this tariff scheme is presented in Figure 21. Furthermore, since January 2014 a dynamic tariff option (updated on a monthly basis) has been implemented for all electricity consumers, which works as a traffic light ("Bandeiras Tarifárias Verde, Amarela e Vermelha"). Thus, consumers would receive a yellow flag when generation costs are rising or a red flag when the previous situation has worsened. These advanced tariff schemes are subject to the substitution of conventional electromechanical meters with smart meters[23].

As complement to the previous tariff structures, the tools used in the Spanish and French demos, where time differentiated price signals are sent to the final consumers with feedback could be directly applied to the Brazilian system. Moreover, local district markets may be created to relief possible network constraints during peak periods. Then network constrains during peak periods could be solved, and also demand could be rationalise during large drought periods where scarcity of energy needs to be well distributed.

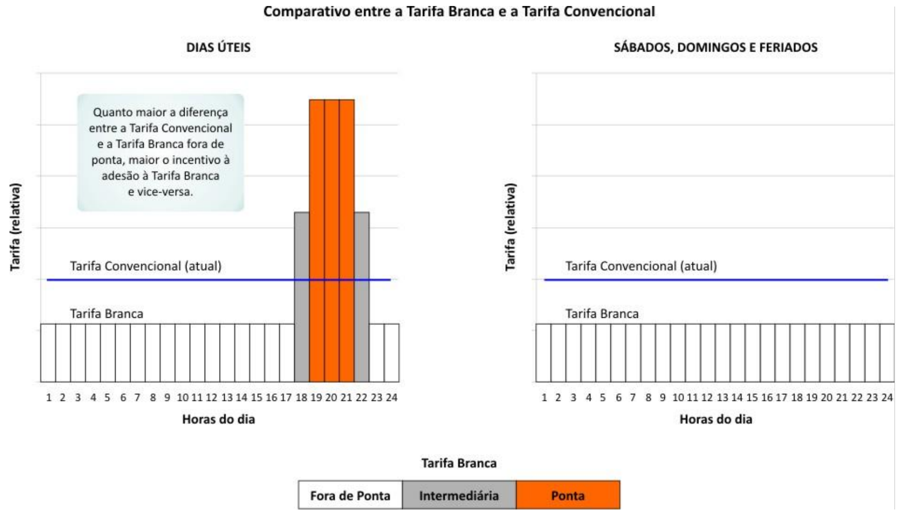



**Figure 21: Tariff design in Brazil "Tarifa Branca". Source: ANEEL**

California is facing important capacity constraints and intermittency problems that make demand response extremely attractive. On top of that, electric loads during peak time on domestic consumers are mostly large air conditioning systems, which could be easily managed as flexible load. It is long time since DR programs have been included in the tariff of final consumers. In this sense, recently adapted options are possible, first participation by third-party vendors, and Demand Response Auction Mechanism (DRAM) a program that would allow demand response providers to get paid today for energy reduction they commit the coming year. Currently, the new DRAM program comprises a floor of 10 megawatts apiece for PG&E and SCE, and 2 megawatts for SDG&E, with at least 20 percent of each to come from the residential sector.

The approach adopted in the French demo -based on local markets for flexible demand and storage- would be of direct application to California system, due to the large availability of

[22] http://www.aneel.gov.br/area.cfm?idArea=781&idPerfil=4
[23] http://www.aneel.gov.br/aplicacoes/noticias/Output_Noticias.cfm?Identidade=4921&id_area=90

distributed resources and the favourable regulatory framework. Indeed air conditioning systems have similar flexibility to water heaters (thermal behaviour), and storage could be aggregated thanks to the large amount of PV rooftop systems installed.

### 3.2.2 Network hosting capacity

The promotion of renewable energy in Europe has resulted in an increased presence of distributed resources in distribution networks. Technical constraints restrict the volume of distributed generation that can be connected to the grid, namely allowed voltage limits in the network and thermal limits of the elements of the distribution system (e.g. conductors, transformers). The Demos of GRID4EU have tested different solutions to increase the hosting capacity of distribution networks, including network reconfiguration in MV networks and voltage regulation in MV and LV networks using OLTC, power factor control of DG units, storage in the form of batteries and flexible demand.

In general, the presence of DG in distribution system in California and Brazil is far inferior to European countries such as Spain, Italy or Germany, as explained in section 3.1. Generation surpassing the demand is still quite rare, and currently, in some cases, distribution substation transformers in California have reverse power relays that prevent back-feed into the transmission system. Under high penetration of DG, these schemes may have to be modified.

*Network characteristics: voltage level, type of network*

Given a maximum voltage variation, higher voltage levels allow for a larger volume of DG. Operating MV voltage levels in Brazil and in California tend to be lower than in Europe: the most usual voltage levels in California and in Brazil are 12.47kV and 13.8kV, respectively, whereas the most common voltage level in Europe is 20kV. In particular, GRID4EU Demo countries have heterogeneous voltage levels: Italy, Spain and France typically have 15 and 20kV networks; in Czech Republic distribution networks are currently being upgraded to 35kV; and Germany or Sweden have mostly 10kV networks. As a result of these lower voltage levels, distribution networks have a lower DG hosting capacity considering the same voltage limits.

Furthermore, the allowed voltage limits in Brazil are more restrictive than regulatory limits in Europe (voltage must remain within the range of -7%,+5% with respect to the nominal value in Brazil, while for most European countries regulation sets a maximum variation of ±10%), so the volume of DG production that can be accommodated is in principle lower.

As a result of the lower degree of undergrounding of distribution networks in Brazil and California and the lower voltage levels, the average R/X ratio of the lines is higher. On the one hand, this translates into a higher impact of DG active power injections on voltage profiles, so that voltage limits are reached for lower volumes of DG production. On the other hand, the impact of reactive power flows in voltage is lower, so power factor control of DG is less effective for voltage rise mitigation.

Rural networks, which typically have longer lines, with conductors of smaller section and a lower degree of undergrounding experience larger voltage variations, especially at the end of the feeders. Actually, the main utilties in California have computed the hosting capacity of their networks for their DRPs based on a best-case/worst-case approach locating DG at the beginning/end of feeders respectively.

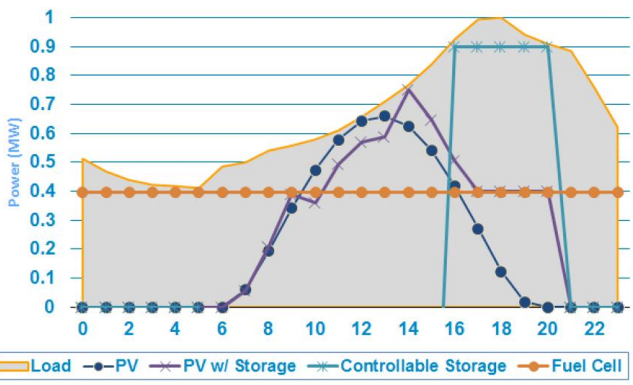
In general, the hosting capacity of the LV grid in Europe is much higher than that of grids in California. The reason is twofold. On the one hand, the standard voltage is much higher in Europe. On the other hand, three-phase systems may integrate a much higher amount of load, or reach further distances, for the same voltage drop. The opposite applies for Brazil, since LV networks are longer and 3-phase systems are more common.

*Distributed generation*

The most important aspects of the DG connected to the grid for its integration are the size, the location where they are connected and dispersion of DG units and the interaction of DG production with local demand.

Large volumes of DG concentrated at the end of feeders cause the largest voltage variations. Dispersion of the DG units favours its integration, since the injection of active power can feed local demand and thus reduce power flows in the system. PV in California is mainly based on rooftop panels of residential consumers, similarly to the case of countries such as for instance Germany, and in contrast to countries like Spain and Italy where larger PV generation parks may be found. In the case of Brazil, the presence of small size DG is almost negligible, and the information available suggests that there are larger generation units that could be connected to higher voltage levels of distribution networks or directly to transmission networks.

The interaction of demand and DG profiles has also been considered by distribution utilities in California in order to determine their network hosting capacity, as can be seen in the example of Figure 22. PV has its maximum generation during mid-day, while peak demand occurs during the evening, so overvoltages or overloads could arise at noon. Fuel-fired technologies, such as CHP and biomass are typically more aligned with demand or have a more flat production curve.




| DER | Limiting Hour | Max Capacity |
|---|---|---|
| PV | 12 PM | 0.66 MW |
| PV w/ Storage | 2 PM | 0.75 MW |
| Controllable Storage | 4 PM | 0.90 MW |
| Fuel Cell | 5 AM | 0.40 MW |

**Figure 22: Assessment of DER capacity depending on profile shapes. Source: PG&E Electric Distribution Resources Plan 2015**

Considering the design of MV networks in California, based on single-phase or double-phase distribution branches, the connection of DG units could increase load unbalance[24] between the three phases on the main feeders and substations.

*Voltage control strategies: OLTC, DG power factor control and storage*

Voltage control in MV distribution networks in Brazil and California relies mainly on the use of

[24] The effect of unbalance is further discussed in section 3.2.4.

OLTC of primary substations, as in European distribution systems. Additionally, autotransformers with tap-changing are inserted in long MV feeders to be used as voltage regulators that compensate voltage drop along the upstream segment of the MV line. Capacitor banks are also connected at specific locations of the networks to inject reactive power and thus modify voltage. The use of voltage regulators contrasts with voltage control in Europe, where this equipment is not as widespread.

In general, the SRA rules derived from technical SRA of the impact of voltage control strategies to improve hosting capacity in MV distribution networks in Europe apply for the cases of Brazil and California, but the use of voltage regulators in rural lines can affect the appeal of other solutions.

For very high penetration degrees of DG, voltage problems may arise when generation exceeds demand. The use of OLTC in primary substations is the most effective solution to lower voltages in the network. Where autotransformers are available, the use of tap changing of voltage regulators based on local measurements is in turn the most effective strategy for local voltage control, since voltage can be modified to the segment of the MV line downstream the transformer.

As observed in GRID4EU technical analysis for European networks, OLTC in primary substations is most fit for homogeneous or distributed DG, since voltage is modified for all outgoing MV feeders. In the case of more concentrated DG, voltage problems are more local and the use of OLTC could worsen the voltage profiles of other outgoing feeders with no DG. However, the use of tap changing of voltage regulators available in Brazil and California, in combination with OLTC in the primary substation, could avoid this problem, setting a different voltage in the corresponding MV feeder.

The control of the power factor of DG units can help mitigate voltage rises caused by DG units. The effect is limited, but it is localized exactly where the problem is caused. It must be taken into account that in the case of overloading of the lines, control of power factor can also help minimize reactive power flows thus decreasing slightly the loading of the lines.

As in Europe, batteries can be used to store the excess of energy injected in the grid by DG, so that larger volumes of installed capacity can be integrated in the grid. In California, the integration of storage has been studied together with other DER in the DRPs. Moreover, prosumers with PV panels at their house sometimes opt for installations including storage. In Brazil, given the large share of hydro, storage is already available at a system level in the form of hydro, so battery storage has not been subject of as much interest.

All in all, the use of tap changing in autotransformers used as voltage regulators in Brazil and California complements the use of OLTC in primary substations and renders the use of other voltage control strategies such as power factor control of DG and storage slightly less attractive than in the case of Europe.

*Reconfiguration to improve network hosting capacity*

As learned from the SRA of the use case of Demo 1, reconfiguration possibilities depend on the structure of the network and switching elements. Switching elements are usually designed for fault management, so available configurations may or may not help balance DG and load in different areas of the network.

It can be concluded that in general, this type of solution is not very attractive to improve the integration of DG. However, it could be useful for seasonal changes in the network in very specific cases of non-homogeneous, concentrated DG for instance to transfer DG to a more loaded section of the network in the case of vocational houses with PV panels.

In conclusion, use cases to increase network hosting capacity are interesting for areas of high penetration of DG, and should focus on the most problematic areas. DG integration in Brazil is presently not a major driver for distribution investments. The increasing penetration of DG in California is being anticipated by detailed analysis in the DRPs and will call for the use of smart grid solutions to efficiently integrate new resources.

### 3.2.3 Network automation for reliability improvement

GRID4EU Demos have tested four different use cases based on automation of the distribution network to improve continuity of supply. The solutions tested involve monitoring and telecontrol of switching elements to improve the process of fault detection, isolation and service restoration (FDIR). Monitoring involves different devices to measure voltages and currents and detect fault-pass in order to locate faults faster. Telecontrol of switches and breakers is aimed at enabling remote operation in order to (i) locate the fault by discarding healthy sections of the grid (the process for fault location is described in gD3.4, see section 3.2.2); and (ii) set a new configuration of the network where non-affected loads are supplied through an alternative path and affected sections are isolated.

*General SRA rules: impact of monitoring and telecontrol in MV networks*

In general, the SRA rules derived for network automation and presented in deliverables gD3.4 and gD3.5 are applicable to network automation in Brazil and California. Relevant technical parameters include network structure and topology and protection schemes. Other technical boundary conditions, such as voltage level, do not affect the upscaling and replication of automation use cases.

As explained in the previous sub-section, distribution networks in Brazil and California have a different topology and different protection schemes. Consequently, the processes for fault management also differ slightly. Switching elements to isolate sections of the network are not located together with MV/LV transformers, so the steps to follow are no longer linked to secondary substations. Given the high share of overhead lines, fault location relies much more on visual inspection, and sections to repair are much more accessible.

The results of the technical SRA performed for GRID4EU use cases are based on a degree of implementation of the monitoring and telecontrol solutions defined as the share of secondary substations equipped with these capabilities. This definition is not applicable to the case of Brazil and California. In the case of Brazil and California, MV automation would take place in the normally-open switches connecting adjacent feeders and at the head of MV feeders. Thus, in general, the elements to upgrade with automation will be lower than in the case of Europe. Notwithstanding, the improvement of continuity of supply achieved by automation would be replicated in Brazilian and Californian distribution networks: the information provided by telecontrolled measuring elements would help locate the fault within a smaller section of the grid, among the two closest elements to the fault, and telecontrol of switching elements would also enable fast service restoration for consumers in healthy sections in meshed networks. Therefore, the impact of monitoring is observed in a reduction of SAIDI, and the impact of telecontrol of switching elements is observed both in SAIDI and SAIFI.

GRID4EU SRA concluded that telecontrol had a very strong impact on the frequency and duration of supply interruptions up to a certain degree of implementation. Beyond an automation degree of 20-30%, the effect is diluted, and the reduction of SAIDI and SAIFI is almost negligible. This SRA rule would translate for the cases of Brazil and California so that the reduction of SAIDI and SAIFI would be very high when implementing automation at a number of points of each MV feeder. However, at a certain point, the incremental improvement achieved by introducing more automation would be quite low, since the additional segmentation of the feeder would imply a shorter distance reduction in the fault management process and the additional consumers recovering service through reconfiguration would be much more limited.

*Network characteristics: type of network, structure*

The higher degree of undergrounding of distribution networks in Europe results in much lower number of temporary faults[25] in comparison to the case of Brazil and California. Moreover, underground networks have typically lower fault rates, which results in higher reliability. However, underground cables are much less accessible, so reparation times are usually much higher than in the case of overhead networks, which could result in higher interruption times for the consumers that cannot be supplied through reconfiguration.

As explained in section 3.1, urban areas have more meshed networks and MV feeders supply a much higher number of consumers. Therefore, the implementation of automation has a much deeper impact than in the case of rural areas. As in Europe, some rural networks may lack interconnection capabilities, and therefore would experience a reduction of interruption times, but a much milder reduction of the frequency of interruptions. In the case of MV feeders with no interconnections, switches and breakers may isolate faulty segments of the network, but there is no alternative path for supply, so it would not be possible to restore service for any consumers connected downstream from the fault. It can be concluded that automation is in principle most attractive and effective for urban areas.

*Automation solution: centralized/local, autonomous/supervised systems*

GRID4EU technical SRA studied the impact of different automation approaches, considering centralized and local intelligence for FDIR, and supervised and autonomous systems. The impact on the frequency and duration of supply interruptions is linked to the response time of the automation system.

- Local / centralized control system: with the local approach, fault isolation is performed automatically by the two automated switches or breakers closest to the fault, while in the case of a centralized control, the breaker at the head of the feeder trips and then a sequential search process must be carried out until the two closest breakers or switches have been operated. In the former case, non-affected loads are discarded at the first step, while in the latter, service restoration is carried out in steps so that a longer time is needed.

[25] When non-permanent faults occur, reclosers are able to reconnect the network once the fault is cleared, so that service is restored within a time of seconds. These events are not monitored through SAIFI and SAIDI, and the implementation of automation has no effect on them.

- Autonomous / supervised control system: the need for a validation from the operator in the control centre adds a certain response time to the execution of FDIR switching actions. In the case of complex situations (e.g.: several faults occurring at the same time in different parts of the grid), this additional response time becomes larger.

Typically, the difference of time required by automation systems to perform FDIR for centralized and de-centralized systems lies within the range of seconds up to a few minutes, depending on the characteristics of the communication technologies in place. In contrast to traditional FDIR performed manually by on-field maintenance crews, these differences are negligible with respect to the time reduction achieved by automation. The supervision of operators adds a longer and more variable time, in the range of minutes, with a direct but mild impact on the achieved SAIDI reduction.

As the degree of automation is higher, the effect of higher response times becomes more influential, since the manual fault management process, which is the most time consuming step, becomes less relevant, and a higher number of automatic operations must be performed.

The reduction of SAIFI is linked to the threshold set by regulation for long interruptions. If automatic reconfiguration is able to restore service for any consumer in a time shorter than the regulatory threshold, this consumer is considered to not have suffered a supply interruption, and is therefore not included in the SAIFI. The different response times of automation systems may result in a larger difference in SAIFI reductions. The regulatory threshold set by regulation in Brazil is, as in most European countries, 3 minutes, while in California the regulator allows for 5 minutes. In the latter, the differences among automation approaches will be less relevant.

*Automation in LV networks*

European LV networks usually have no or very little reconfiguration options, only LV networks in highly populated cities may have LV cabinets in the streets interconnecting LV lines. Technical SRA concluded that LV automation is much less promising that MV automation, since the reduction of interruption frequency and duration is much lower and would require much more infrastructure to affect a lower number of consumers. Both in Brazil and in California, the architecture of LV networks, or the lack of proper LV networks, renders LV automation even less attractive than what it was already observed for the European case.

*Quality of service regulation: Reliability indices*

Continuity of supply in distribution networks is driven by regulation: monitoring of reliability indices, targets and economic incentives to distribution companies guide their strategy and investment. The effect of the threshold set by regulation for interruptions of supply has been discussed previously discussed together with the different automation solutions.

The different indices used for targets and incentives for continuity of supply were also studied in GRID4EU in gD3.4 & gD3.5. Both in Brazil and in California, as is the case in most European countries, reliability indices are SAIFI and SAIDI, which are based on the number of consumers. Therefore, all consumers are given equal importance regardless of their size and reliability improvement is prioritized for more densely populated areas.

### 3.2.4 LV supervision and control

Regarding network supervision and control there are some major differences between distribution networks in Europe and those in California and Brazil. In Europe typical distribution networks are underground, while in California and Brazil distribution networks are mainly overhead. Some exceptions are some high consumer density areas, like business districts in big cities, having underground networks.

On the one hand, considering that on average 80% of outages are in LV networks, the number of outages in underground cables are far less than overhead distribution (an improvement of 10 times on average). However, in radial networks such as rural and semiurban areas, the repair and duration of the failure time is longer (up to 10 times longer). So at the end these two effects counterbalance each other mainly in rural areas. On top of that, the distribution and location of final consumers makes the difference: very scattered in California compared to Europe. Then, for each line and the same number of faults than European networks, a lower number of consumers are affected by each LV fault. The situation is rather the opposite as in the Swedish case where there are very long LV lines.

A second benefit for supervision of the distribution network is to eliminate unbalances in the network. Current unbalances are located in the low voltage networks in Europe. A similar situation may be found in some networks in Brazil. However, in California low voltage and medium voltage networks are typically single phase, so the effect of unbalances in energy losses and conductor overloading is lower. Then, phase unbalance analysis presented in gD3.4 and gD3.5 would therefore not be applicable to this case.

A third key benefit from network supervision is metering. In California metering is already working as a tool for the distribution company to adequately host additional DG, mainly PV. However, in the case of Brazil, this solution can be a priority in order to reduce the extremely high levels of non-technical losses rather than to enable the integration of DG or EVs in the LV grid. Energy theft in Brazil is favoured by overhead lines. Therefore, the focus should be placed on loss detection instead of phase unbalance.

The supervision and control of the network requires to build an additional communication layer. The type of communications may be affected as well by network topology. The use of concentrators and GPRS loses its appeal for network structures such as the Californian one since each distribution transformer serves a very low number of meters, thus requiring a much higher number of concentrators and GPRS points. Due to the lower density of load and the higher number of secondary transformers, the communications architecture may introduce an additional step. The last mile may be reached through PLC from the meter to the transformer. Sometimes wifi or Zigbee may be used to communicate directly to the concentrator, enabled by the shorter distances between consumers and secondary transformers and to skip one step in the communications architecture. Then, radio-frequency is used to communicate with the data concentrators that cover several distribution transformers. Lastly, GPRS-GSM is used to send the data to the central systems. Wimax is used where there is reception for this network[26]. See, for instance, the AMI

[26] The lack of appropriate reception of telecommunications networks can be a major barrier in Northern and Western Brazil, especially in the Amazonia, due to the significantly widespread population and absence of infrastructure.

communications architecture implemented by the company CEMIG in a demonstration project in the state of Minas Gerais.

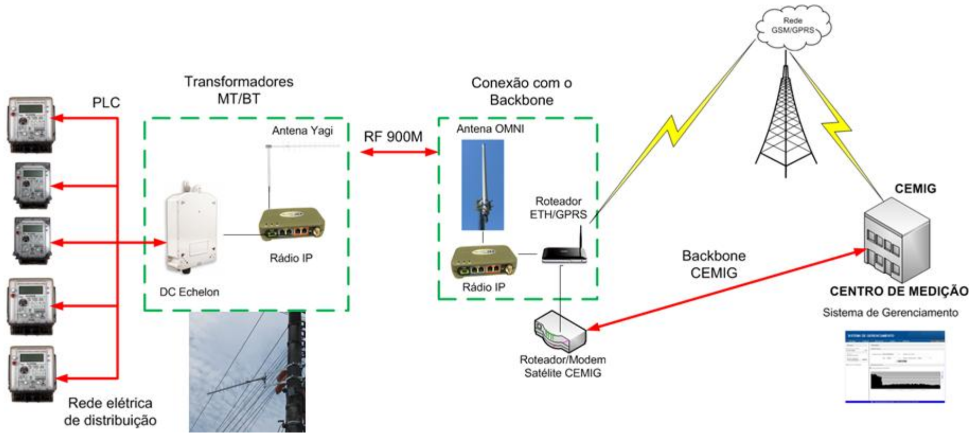



**Figure 23: AMI communications architecture in the pilot project "Cidade do Futuro" implemented by the company CEMIG. Source: (Cemig 2014)**

### *3.2.5 Anti-islanding protection system*

GRID4EU has tested anti-islanding protection schemes for PV connected to the MV network through inverters. The objective is to avoid unintentional islanding caused by DG injections that can supply local demand in the event of a fault.

The current replicability potential of this use case to Brazil is quite limited, since the presence of PV in MV networks is not significant. In the case of California, there is an actual concern regarding anti-islanding. Since penetration levels of DER are still low, distribution utilities are currently relying on the imbalance between DG generation and demand. However, companies acknowledge the need for disconnection systems for higher penetration degrees of DER in their DRPs and propose smart systems, based on communications, as proposed by Demo 4 of GRID4EU.

# 4 Non-technical boundary conditions affecting scalability and replicability

As a complement to the technical evaluation of the replicability potential of GRID4EU solutions presented in the previous section, the potential barriers and drivers posed by the existing non-technical boundary conditions in California and Brazil are explored on the ensuing. The focus will be mainly placed on the differential regulatory settings in these regions as compared to the EU context (see section 4.3). Some noteworthy stakeholder issues will be incorporated in the analysis when relevant. The topics analyzed, described in section 4.1 and section 4.2 for California and Brazil respectively, include: distribution regulation, smart meter deployment, RES promotion policies, self-consumption, energy storage, incentives for smart grid demonstration projects and treatment of DG units.

## 4.1 Non-technical boundary conditions in California

Before addressing the specific case of California, it is relevant to describe briefly some of the fundamental differences in the approaches to distribution regulation in the US as compared to the EU. Broadly speaking, each US state where liberalization and privatization has been introduced has usually created an independent utilities commission that regulate electric utilities. Oftentimes, these institutions are in charge of supervising other utility services too, such as water, gas or telecommunications. Interstate energy issues (e.g. transmission interconnections or licensing large hydro projects) are under the responsibility of the FERC, whereas market design and supervision and transmission expansion are main tasks of the ISOs (in the states or regions where these exist).

In the EU, energy regulators typically rely on fixed regulatory periods after which they centrally determine the allowed revenues of all DSOs in the country following some pre-defined rules established in laws or other regulatory documents. On the contrary, US regulatory commissions hold the so-called rate cases where they review the overall utility tariffs on a case by case basis. Thus, it is possible that different utilities are subject to distinct rules if such is the result of their rate cases. These rate cases may be initiated either on a periodical basis, or through a request from the regulator, a utility or even stakeholder groups such as consumers' representatives. These processes may be seen as quasi-judicial proceedings where utilities have to present detailed investment plans and rate proposals. Additionally, other parties are usually invited to present their views. Lastly, the commission reaches a final decision.

The previous approach broadly describes the case of California. The regulatory approach followed by the CPUC is essentially a cost of service regulation, complemented with performance-based incentives related to quality of service. Further details on the Californian experience with PBR are provided below. At the moment, the CPUC carries out rate cases for electric utilities every three years for the three major IOUs in the state. At the beginning of such periods, the commission sets the allowed revenues for the first year, also referred to as test year, as well as the next two years, referred to as attrition years. The allowed revenues cover the actual utilities' O&M costs, depreciation, a return on capital and taxes. Note that utilities are hedged against any deviation between the revenue collection and revenue requirements, which may be caused by incorrect demand forecasts, energy efficiency or net-metering; thanks to the fact that revenue decoupling has been implemented. Hence, if any deviation is observed, a rate adjustment is made in subsequent years (Morgan 2013).

Incumbent utilities were mandated to significantly unbundle distribution from their conventional businesses of transmission and centralized generation to spur competition (Mota 2004). Nonetheless, utilities in California may still be considered as vertically integrated despite the fact that they have to purchase a significant amount of their electricity demand from external generators, since they may own generation assets and act as suppliers for most end consumers within their concession areas (Morgan 2013). Consequently, the revenue requirements calculated at rate cases include generation and retail costs as well as distribution costs.

The use of PBR to regulate Californian electric utilities was mentioned above. In this regard, reliability standards are set on the following indicators per utility: SAIDI, SAIFI, CAIDI and MAIFI[27]. Since momentary interruptions are not generally monitored and used as revenue drivers for European DSOs, the focus will be placed on sustained interruptions. Note that these are also the focus of GRID4EU use cases aimed at reliability improvement. In California, the threshold beyond which a supply interruption may be considered as a sustained outage is of 5 min, which is higher than the 3 min commonly used in Europe. Concerning the design of reliability incentives, symmetric incentive-penalty schemes are in place. These address both average reliability levels as well as worst served areas, and include dead-bands and caps/floors in their designs. Specific figures for all the parameters involved are utility-specific. For illustrative purposes, Table 8 shows the main features of the reliability incentive scheme for SDG&E utility in the 2015 PBR.

| | SAIDI (minutes) | SAIFI (outages) | Ten Worst Circuit SAIDI (minutes)* | Ten Worst Circuit SAIFI (outages)* |
|---|---|---|---|---|
| 2015 Benchmark | 60 | 0.51 | 585 | 4.40 |
| Dead Band | + / - 2 | + / - 0.02 | + / - 35 | + / - 0.35 |
| Increment | 1 | 0.01 | 10 | 0.10 |
| Annual Improvement | 1% | 1% | n/a | n/a |
| Reward/Penalty Increment | $375,000 | $375,000 | $125,000 | $125,000 |
| Maximum | $3,000,000 | $3,000,000 | $1,000,000 | $1,000,000 |

**Table 8: Performance-based reliability incentives for SDG&E in 2015 PBR. Source: (SDG&E 2015)**

Tree trimming to prevent fires[28] and large-scale blackout in transmission lines as well as utility response during storms are also monitored following specific regulation. Fines may be set for failing to comply with the standards. Furthermore, additional utility incentives were in place in the past related to customer satisfaction and health & safety. However, the regulator found out that due to an inadequate design and reporting procedures, perverse incentives were provided to utilities which, as reported in  (Whited et al. 2015), tampered with the indicators calculation and reporting. Some of the worst consequences of these undesired effects was that employees were incentivised not to report health and safety problems or that consumers were lied at or given merchandising

[27] Excluding major events and non-distribution caused events.

[28] http://www.cpuc.ca.gov/General.aspx?id=1974

material by utility employees so as to obtain better evaluations in the satisfaction surveys. Contrary to what is commonly done in Europe, no incentive scheme is in place specifically targeting energy losses reduction.

As mentioned in section 3.1.1, the major IOUs in California have reached virtually a 100% penetration of smart meters in their concession areas. However, the approach followed for this deployment presents similar differences with respect to Europe as the case of distribution regulation. EU countries have generally carried out, or are generally carrying out, a roll-out based on a centralized policy mandate, which also defines common metering technical functionalities. On the contrary, the CPUC has authorized IOUs on an individual basis to substitute electro-mechanical meter with digital ones, being the main goals to provide consumers with energy usage information and advanced tariff schemes, reduce meter reading costs, and outage detection[29]. Due to the fact that IOUs are vertically integrated, the regulatory discussions do not tackle issues related to data access and management for retail competition facilitation.

An important feature of the Californian roll-out is that opt-out options had to be introduced due to the public opposition to smart meters, mainly driven by health concerns about wireless communications[30]. These consumers are charged an additional amount, both an initial fee and an extra monthly charge, due to the incremental costs or meter replacement and reading (CPUC 2012a; CPUC 2012b; CPUC 2014). In spite of this clause, the number of consumers who opt-out of smart metering is under 1% state-wide, as shown in Table 9.

| IOU | Electric Opt-out (Nº of customers) | Total number of smart meters (million) | Opt-out share |
|---|---|---|---|
| PG&E | 52205 | 5,48 | 0,95% |
| SDG&E | 2752 | 1,43 | 0,19% |
| SCE | 22574 | 5 | 0,45% |
| Total | 77531 | 11,91 | 0,65% |

**Table 9: Smart metering opt-out situation in California as of October 2015. Source: (CPUC 2016)**

Moving beyond utility regulation, upscaling and replicability potential of GRID4EU solutions will be affected by the regulatory conditions for DER deployment, especially DG. The connection of generators to the distribution grid in California has been largely driven by support mechanisms similar to the European situation. In fact, California is one of the leading states in the promotion of RES, being the RPS on the large IOUs one of the major promotion policies. The overall targets set by regulation are to achieve a 33% of the energy delivered at retail level to be produced from RES by 2020, and up to 50% by 2030 according to the Senate Bill 350 signed on October 2015[31]. Nonetheless, RPS is not the only policy instrument promote RES production in California.

Following (CPUC 2013b), both IOU and publicly-owned utilities with more than 75000 customers must offer a form of FIT until an overall target of 750MW are reached, for RES generation units of up to 3MW, and 250MW exclusive to bioenergy generation[32]. The goal of this program is to support the utilities in complying with their corresponding RPS targets. Thus, in exchange for the FIT, the

29 http://www.cpuc.ca.gov/General.aspx?id=4853
30 http://stopsmartmeters.org/
31 http://www.leginfo.ca.gov/pub/15-16/bill/sen/sb_0301-0350/sb_350_bill_20150911_enrolled.pdf
32 http://programs.dsireusa.org/system/program/detail/5665

utilities receive the renewable certificates corresponding to the production under this program. Nonetheless, the most relevant mechanism to promote small-scale DG are the existing self-consumption and net-metering policies, for which installations of up to 1MW are eligible. Self-consumption and net-metering have been popular policies for many years, as it is the case all across the US; 41 states, DC and some additional territories in the US had adopted some form of net-metering by January 2016 (see Figure 24).

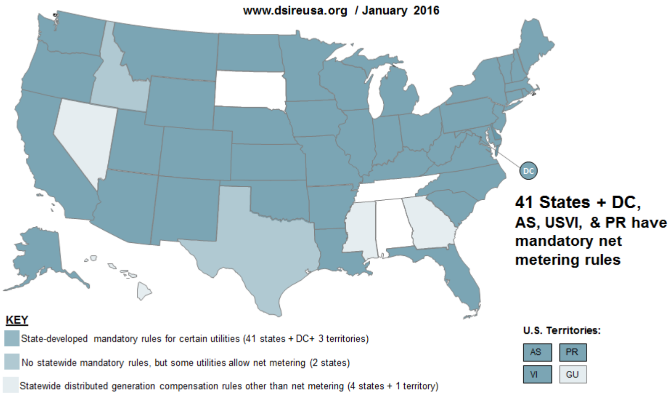



Figure 24: Overview of net-metering penetration across the US. Source: DSIRE database[33]

The large Californian IOUs in particular, are mandated to offer their customers the possibility of net-metering until July 2017, without any expiration date set for the credits originated from production surpluses. In order to protect utilities against the missing money problem, a cap on the overall eligible PV capacity was set per utility, calculated as 5% of each utility's peak demand. As of March 2015, approximately 45% of the total capacity was still available (see Table 10). Additionally, prosumers are allowed to aggregate the consumption and generation recorded by different meters, as long as all these belong to the same agent. Lastly, the so-called virtual net-metering is permitted to allocate the credits generated by DG units located in multi-tenant properties (e.g. apartment building with rooftop solar), according to a pre-defined allocation agreement[34].

| Utility | Net-metering Cap (MW) | Remaining Capacity March 2015 (MW) |
|---|---|---|
| PG&E | 2409 | 980,3 |
| SCE | 2240 | 1156,9 |
| SDG&E | 607 | 213,7 |

Table 10: Cap on capacity entitled to net-metering per IOU in California (as of March 2015). Source: CPUC[35]

In order to efficiently integrate the resulting growing penetration of DG, the CPUC has mandated IOUs to develop individual DRPs where, as already mentioned in section 3.1.1, they ought to identify optimal locations and strategies for the deployment of DER, comprising DG-RES, energy efficiency, energy storage, EVs, and demand response. These plans were submitted to the

[33] http://www.dsireusa.org/
[34] http://www.cpuc.ca.gov/General.aspx?id=5408
[35] http://www.cpuc.ca.gov/General.aspx?id=3800

regulator at the beginning of July 2015 for their approval. The full information of these plans and data disclosed by the IOUs can be found at the CPUC's webpage[36]. These plans include very detailed information on the distribution network characteristics of each utility as well as the modelling assumptions used in the so-called integration capacity analysis, which is no more than an estimation of the available hosting capacity in different network areas. Additionally, the three largest IOUs have disclosed detailed information used as an input and results of such analysis, including GIS-based data. For example, shows a screenshot of an interactive map where users may check the available capacity for generation connection in the different network elements made publicly available by SCE. Likewise, Figure 26 shows an example of the forecasted loading of a specific feeder used by PG&E as an input for evaluating its DER hosting capacity. Similar information is provided by this utility for the different substations and MV feeders.

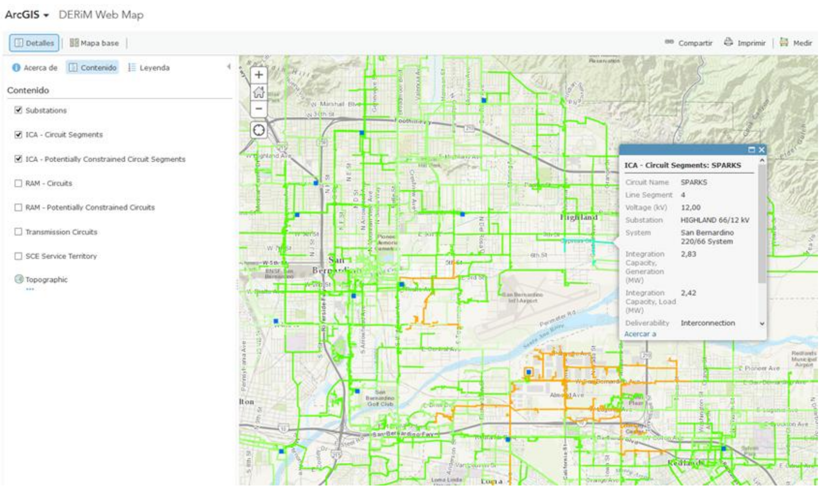



Figure 25: SCE distributed energy resource integration map. Source: SCE[37]

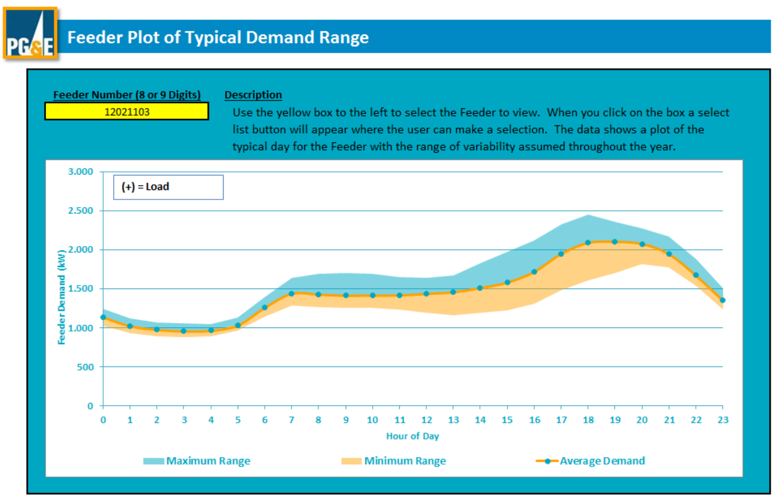



Figure 26: Feeder loading forecast used as input for PG&E's distribution resource plan

[36] http://www.cpuc.ca.gov/General.aspx?id=5071
[37] http://www.arcgis.com/home/webmap/viewer.html?webmap=e62dfa24128b4329bfc8b27c4526f6b7

In addition to the promotion of RES, the state of California is pioneering the deployment of energy storage through the setting of binding targets to the three largest IOUs. According to the decision from the CPUC in (CPUC 2013a), these utilities must procure 1325MW of storage capacity by 2020, which should be installed no later than 2024. These targets are broken down per utility and type of storage application/location, being excluded from eligibility pumped storage installations above 50MW. Three types of storage applications, with separate goals, are identified: transmission, distribution, and customer storage (see Table 11). In order to comply with this requirement, utilities shall carry out competitive tenders, before which IOUs must to submit justified procurement plans to the CPUC for evaluation. Note that, despite the fact that utilities play a central role in this scheme, they are only allowed to actually own 50% of the overall capacity installed across all applications.

| Utility | Storage application-location | 2014 | 2016 | 2018 | 2020 | Total |
|---|---|---|---|---|---|---|
| SCE | Transmission | 50 | 65 | 85 | 110 | 310 |
| | Distribution | 30 | 40 | 50 | 65 | 185 |
| | Customer | 10 | 15 | 25 | 35 | 85 |
| | SubTotal | 90 | 120 | 160 | 210 | 580 |
| PG&E | Transmission | 50 | 65 | 85 | 110 | 310 |
| | Distribution | 30 | 40 | 50 | 65 | 185 |
| | Customer | 10 | 15 | 25 | 35 | 85 |
| | SubTotal | 90 | 120 | 160 | 210 | 580 |
| SDG&E | Transmission | 10 | 15 | 22 | 33 | 80 |
| | Distribution | 7 | 10 | 15 | 23 | 55 |
| | Customer | 3 | 5 | 8 | 14 | 30 |
| | SubTotal | 20 | 30 | 45 | 70 | 165 |
| All IOUs | Transmission | 110 | 145 | 192 | 253 | 700 |
| | Distribution | 67 | 90 | 115 | 153 | 425 |
| | Customer | 23 | 35 | 58 | 84 | 200 |
| | Total | 200 | 270 | 365 | 490 | 1325 |

**Table 11: Storage deployment targets (MW) set on Californian IOUs per application. Source: (CPUC 2013a)**

Last but not least, an essential non-technical boundary condition corresponds to the policies enabling and promoting the deployment of smart distribution grid technologies. At Federal level, the Recovery Act (ARRA) of 2009, known as the Recovery Act (US Congress 2009), boosted the development of smart grid demonstration projects in the US. According to this Law, €4.5billion were assigned to the US DOE specifically to promote the modernization of the power system. Pilot projects were mainly supported through two programs: the Smart Grid Investment Grant (SGIG) and the Smart Grid Demonstration projects (SGDP). Overall, more than 130 demonstration projects covering different smart grid realms were financed. The full information about the projects funded under the ARRA can be found in a database set-up by the DOE[38].

In the specific case of California, 16 demonstration projects were funded under this program, amounting to over $398million of ARRA funds and a total cost of over $1.2billion. The topics addressed by these 16 projects are summarized in Figure 27. Note that since each project may cover more than one of the smart grid functionalities, the summation does not add up to the total number of projects. A detailed account of the latest advances in the field of smart grids in California

[38] https://www.smartgrid.gov/recovery_act/project_information.html

can be found in (CPUC 2016).

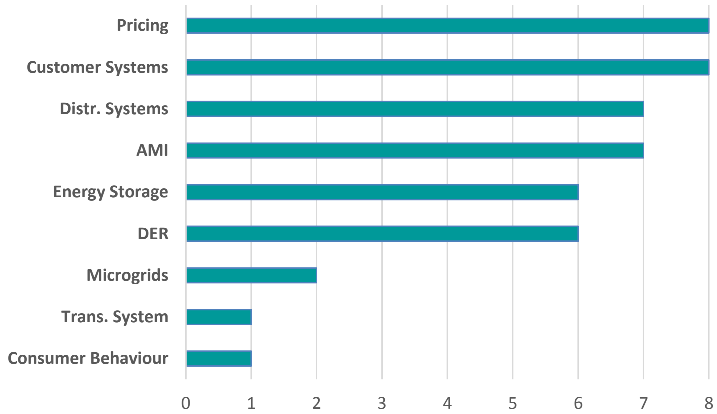



**Figure 27: Smart grid applications addressed by smart grid pilot projects funded under ARRA in California. Source: Own elaboration; data from www.smartgrid.gov**

The previous figure denotes that a strong emphasis has been placed on demand response related aspects such as pricing mechanisms, customer systems or AMI. This finding is consistent with the fact that, as discussed in section 4.3, the Californian system can greatly benefit from an enhanced demand flexibility. On a second level, one may find solutions aiming to improve distribution network operation (mainly MV automation, and OMS-DMS upgrades) and DER integration, including energy storage (in this case focusing on large-scale solutions). Lastly, two microgrid projects can be found in the list, namely the Borrego Springs microgrid and the Santa Rita Jail microgrid. Additionally, there is another relevant microgrid in operation in California at the University of California at San Diego[39].

The issue of microgrids is very relevant in California, and all over the US, for its application to sensitive loads such as universities, prisons or military bases. In fact, there is a specific program for enhancing the reliability of power supply in military basis called SPIDERS (Smart Power Infrastructure Demonstration for Energy Reliability and Security)[40].This is mainly driven by policy and public perceptions about the importance of security of supply, reliability and resiliency (both physical and cyber security), in order to face challenges related to extreme weather events (more relevant for the east coast than for California), terrorism and sabotage. In particular, in California there have been presumed terrorist attacks specifically targeting the power system[41].

## 4.2 Non-technical boundary conditions in Brazil

Electricity distribution in Brazil may be carried out by two types of companies: the so-called

[39] https://building-microgrid.lbl.gov/ucsd
[40] http://energy.sandia.gov/wp-content/gallery/uploads/SPIDERS_Fact_Sheet_2012-1431P.pdf
[41] A sniper attacked a PG&E transmission substation in April 2013, which has been suspected of being an organized terrorist attack. This was reported a few months later on by the major media:
http://edition.cnn.com/2014/02/07/us/california-sniper-attack-power-substation/index.html
http://www.foxnews.com/politics/2014/02/06/2013-sniper-attack-on-power-grid-still-concern-in-washington-and-for-utilities.html
http://www.wsj.com/articles/SB10001424052702304851104579359141941621778

"permissionárias de distribuição", which are small cooperatives in rural areas, and the so-called "concessionárias de distribuição", which are larger public/private distribution companies. The former are subject to a simplified regulatory supervision. Nonetheless, the 38 cooperatives serve on aggregate around 0.6% of the overall distribution consumers in Brazil. Therefore, on the ensuing the focus will be placed on the 63 large distribution companies or *concessionárias* that had been mentioned in section 2.2.

The overall regulatory process in Brazil is similar to the European approaches, where the energy regulator periodically sets the allowed revenues or prices for a given period of time on the basis of the framework laid down in regulation[42]. More specifically, a price cap remuneration formula with four-year regulatory periods is used to regulate distribution companies in Brazil. The price cap at the beginning of the regulatory period is calculated following a building blocks approach to calculate the allowed TOTEX of each firm (ANEEL 2015a). Allowed OPEX are determined on the basis of efficiency analysis using historical information as input data following DEA models (ANEEL 2015b). On the other hand, CAPEX are computed as the annuity of the RAB, which is determined as the replacement cost of existing assets using average unit costs (book values are considered for some asset categories). A linear depreciation method is followed to update the RAB in between tariff revisions (ANEEL 2015c). In both cases, the rate of return is calculated as the WACC (a single value is used for all companies) (ANEEL 2015d).

Similarly to the case of California, distribution companies are not subject to as tight unbundling requirements as in the EU. Hence, distribution companies may own generation assets and even transmission assets operated under the command of the ONS. Moreover, distribution companies act as retailers for captive consumers within their concession area. Distribution companies may not own more than 30% of the demand of their captive market in terms of generation capacity (Mota 2004). Therefore, allowed revenues of distribution companies, albeit not mentioned above, include the corresponding costs for these activities. Notwithstanding, accounting unbundling is in place, so that separate accounts must be kept for each activity.

As a complement to price regulation, several output or performance indicators are embedded into the distribution regulatory framework. The most important category of performance indicators is presumably the continuity of supply which, together with the commercial quality of service levels, is taken into account to modify the X factor of each distribution company[43]. Thus, the X factor is calculated as the summation of three components: i) a correction for changes in the number of consumers supplied and the amount of electricity delivered (necessary to hedge the risks of distribution companies under price cap regulation), ii) a quality component, and iii) an efficiency target component (ANEEL 2015e).

The focus will be placed on the second of these terms which is related to output indices, i.e. the quality of service component. Both technical and commercial quality indicators as considered as described in (ANEEL 2015e). The technical quality (continuity of supply) indicators are the DEC and FEC already mentioned in section 3.1.2, whereas several commercial quality indicators are

[42] All the relevant documents may be found at:
http://www.aneel.gov.br/area.cfm?idArea=702&idPerfil=2

[43] The X factor in a price or revenue cap regulation affects, usually together with a price index, the annual revenues or prices a distribution company is entitled to recoup through the network tariffs. This is the reason why this regulation is oftentimes referred to as RPI-X regulation.

considered including: customer satisfaction, frequency of complaints and quality of telephone service. Companies which perform badly according to the selected indicators are given a higher value of the X factor (lower remuneration) than those in the upper tiers of performance. Moreover, this reduction in revenues is more noticeable in the case of those companies which do not reach a pre-defined minimum threshold. Hence, under this mechanism distribution companies are benchmarked against a fixed reference level and also against other distribution companies. This can be seen in Figure 28, which shows how the Q-factor that is subtracted from the X factor of each distribution company would be modified as a function of the company's DEC (equivalent to SAIDI).

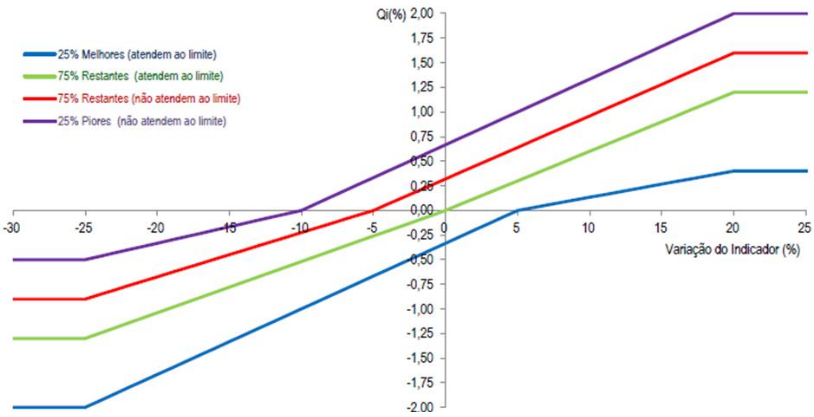



**Figure 28: Variation of the Q-factor added to the X-factor as a function of the DEC reliability index used to determine the annual allowed prices of Brazilian distribution companies. Source: (ANEEL 2015e)**

Distribution companies are also exposed to loss reduction economic incentives. This is done by passing-through to the tariffs only a pre-defined share of losses, being distribution companies responsible for purchasing all their network losses. Hence, if actual losses are lower than the regulatory ones, the firms would earn a benefit and vice versa. The aforementioned share of losses is calculated for each distribution company as the summation of technical and non-technical losses as defined in (ANEEL 2016a) and (ANEEL 2015f) respectively. The computation of the former is based on detailed electro-technical analyses and network modelling, whereas the latter depend on a parameter which measure the socio-economic "complexity" of the concession area of each distribution company.

In addition to the previous incentive schemes which have a direct impact on the distribution tariffs paid by all end consumers, distribution companies have to pay direct economic compensations (of give discounts on the consumers' monthly bill) in case of violation of different individual quality of service indicators. These comprise individual indicators of the frequency and duration of supply interruptions and power quality indices (ANEEL 2016b). The recorded levels of voltage power quality and the yearly compensations paid by each distribution company in Brazil can be consulted at the regulator's webpage[44]. Three tiers of bus voltage levels are defined: normal operating voltages, precarious voltages and critical voltages. The voltage levels corresponding to each one of these tiers are shown in Table 12. Individual compensations must be paid in case precarious voltages are recorded for more than 3% of the measurements and in case critical voltages exceed

[44] http://www.aneel.gov.br/aplicacoes/Indicadores_de_conformidade_nivel_tensao/pesquisa.cfm?regiao=SE

0.5% of the measurements. These measurements as well as the calculation of the economic compensations are measured on a quarterly basis.

| Voltage level | Voltage limits | | | | | |
|---|---|---|---|---|---|---|
| | Normal | | Precarious | | Critical | |
| | Drop | Rise | Drop | Rise | Drop | Rise |
| ≥ 230kV | 5% | 5% | 5-7% | 5-7% | >7% | >7% |
| 69-230 kV | 5% | 5% | 5-10% | 5-7% | >10% | >7% |
| 1-69kV | 7% | 5% | 7-10% | - | >10% | >5% |
| < 1kV | 8% | 5% | 8-13% | 5-6% | >13% | >6% |

**Table 12: Voltage limits defined in the Brazilian distribution codes. Source: (ANEEL 2016b)**

As mentioned in section 3.1.2, smart metering roll-out in Brazil is still in an early stage, in spite of having defined technical requirement for electronic meters several years ago and being it clear that distribution companies would be the agent in charge of meter deployment and data management (ANEEL 2010b). In 2012, ANEEL mandated an opt-in roll-out of smart meters for LV consumers (except low-income and public lighting) (ANEEL 2012c). The same resolution gave distribution companies a period of 18 months to adapt metering systems and start offering this technology to their customers. However, this deadline was suspended in February 2014, just before its expiration, in order to revise the technical requirements of metering technologies and to provide distribution companies further time for adaptation (ANEEL 2014). Among the main drivers stated by the regulator, the following are comprised: LV fault detection, loss reduction (including remote meter management for connection and disconnection), ToU and dynamic pricing, and DG support.

Let us now shift the focus away from the regulation of distribution companies in order to describe the current regulatory conditions for DG in Brazil, starting by the support mechanisms for these technologies. The main policy instrument to promote RES in Brazil nowadays are the technology-specific capacity auctions, which are also devised as a capacity mechanisms to ensure the long-term generation adequacy. These are periodical tendering processes (quantity-based) that result in a form of FIT whose level is determined by competitive forces. Note that competitive quantity-based support schemes tend to favour least-cost technologies and higher unit sizes. This would explain the current low level of penetration of solar technologies in Brazil, in favour of large-sized wind farms and bioenergy generators. Detailed description of the implementation details and results of such mechanisms can be found at (Batlle and Barroso 2011; Mastropietro et al. 2014).

However, alternative mechanisms have been implemented which would be more suitable for small-sized DG-RES installations. On the one hand, the PROINFA program, which essentially consisted in a FIT whose cost was defrayed by all electricity consumers, was implemented in 2002 so as to promote the deployment of small-scale hydro, wind and biomass generators. This program was closed for new installations in 2011, when up to 131 installations (60 small hydro, 52 wind and 19 biomass generators) have been selected for support[45].

On the other hand, a specific net-metering program was approved in 2012, targeting micro- and mini-generation which is defined by regulation as those units below 100kW and as units between 100kW and 1MW respectively (ANEEL 2012b). In order to be eligible for this program, generators

45 http://www.aneel.gov.br/aplicacoes/noticias/Output_Noticias.cfm?Identidade=8277&id_area=

must be based on RES or high-efficiency CHP. The production credits given for production surpluses are valid for a period of 36 months. In order to mitigate the potential negative effects of net-metering on system fixed-costs recovery (missing money), minimum bills have been introduced for LV consumers (group B), whereas demand charges ($/kW) apply to HV consumers (group A). Even community net-metering is allowed under certain circumstances. The installed capacity per technology resulting from this program was described in section 3.1.2, and more specifically Table 5.

Despite the fact that DG penetration levels in Brazil are still rather low as compared to the leading EU countries (including several GRID4EU countries) or California; distribution regulation already considers DG in several instances. Firstly, distribution network planning, particularly at the HV and MV levels, ought to consider existing and foreseen DG units for the purposes of demand forecast and definition of planning scenarios (ANEEL 2015g). Moreover, DG units must keep a power factor close to unity (normally better than 0.95 leading or lagging) when connected to the grid as defined in (ONS 2010; ANEEL 2016b). Lastly, the grid connection/access rules estipulate that DG units must be granted least-cost network access. Connection costs are to be defrayed by DG promoters, i.e. connection charges are deep, although the distribution company has to provide evidence that the connection alternative offered is the least-cost one. A simplified fast-track administrative procedure for grid connection is in place for mini and micro generation (RES units below 1MW).

Concerning the access of DG to the grid, the distribution grid codes establish size limits for the connection of DG to specific voltage levels. It can be seen in Table 13 that for sizes above 500kW, the connection must be made to the HV or MV level, while generators larger than 30 MW would be necessarily connected to the HV level. Note that this tiers are broadly consistent with the estimation of DG penetration presented at the end of section 3.1.2. Regardless of the size, all DG units must be equipped with over/under frequency and over/under voltage protections[46]. Generators larger than 300kW must be equipped with voltage and frequency control functionalities. Moreover, a technical evaluation of the possibility is islanded operation supported by these units (>300kW) must be performed, including an estimation of the consumers that could be affected as well as its impact on the quality of service (ANEEL 2012a).

| Installed Capacity | Voltage level at the point of connection |
|---|---|
| < 10kW | LV (single-phase) |
| 10 to 75 kW | LV (three-phase) |
| 76 to 150 kW | LV (three-phase)/MV |
| 151 to 500 kW | LV (three-phase)/MV |
| 501 kW to 10 MW | MV/HV |
| 11 to 30 MW | MV/HV |
| > 30 MW | HV |

**Table 13: Criteria for voltage level connection as a function of DG size in Brazil. Source: (ANEEL 2012a)**

As in the case of California, the last topic addressed in this review is that of policies and mechanisms used to promote and support the implementation of smart grid solutions. On the one

[46] This particular feature is a relevant aspect concerning the potential unintentional islanded operation, which is the main focus of a Demo 4 use case.

hand, every year, distribution companies (as well as generation and transmission companies) must spend at least a pre-defined share of their net operating revenue on R&D projects in areas related to, among others, network planning and operation, integration of DG-RES, energy efficiency, quality of service or system supervision, protection and control. In the case of distribution, the share as of January 2016 is of 0.3%. In addition to this R&D expenditures, distribution companies receive funds from different federal programs that, together with the previous 0.3%, reach up to 1% of the net operating revenues of each firm[47].

Nevertheless, the projects financed under the previous program correspond to R&D projects whose results may comprise methodologies, concepts, software developments, systems, materials, devices or machines/equipment (ANEEL 2008). Thus, in order to specifically promote demonstration and pilot projects, another program was introduced by ANEEL in 2010 (ANEEL 2010a), after being proposed by the company CEMIG and endorsed by other 36 distribution and generation companies. Nine smart grid demonstration projects have been approved and included in this strategic initiative, some of which were already mentioned in section 3.1.2, in relation to AMI deployment. The full information of these projects and the participants may be found at a dedicated webpage[48].

| Distribution Company | Project-City name | AMI-AMR | FDIR | Volt/VAR control | DG | EV | Storage | DSM | Home autom. | Smart appliances |
|---|---|---|---|---|---|---|---|---|---|---|
| CEMIG | Cidades do Futuro | X | X | X | X | X | | | X | |
| Ampla | Cidade Inteligente Búzios | X | X | X | X | X | X | X | X | X |
| Light | Smart Grid Light | X | | | X | X | | X | X | X |
| Eletrobras Am. | Parintins | X | X | | X | | | X | | |
| Eletropaulo | Programa SG - Eletropaulo Digital | X | X | X | | | | X | X | X |
| EDP Bandeirante | InovCity | X | X | X | X | X | | X | X | X |
| Copel | Paraná Smart Grid | X | X | | X | X | | X | X | X |
| CELPE | Arquipélago de Fernando de Noronha | X | | | X | X | X | X | X | |
| COELCE | Cidade Inteligente Aquiraz | | | X | | | X | | | |

Table 14: Smart grid demonstration projects in Brazil. Source: Project "Redes Inteligentes Brasil"

Table 14 summarizes the main technologies and functionalities tested in each project. It can be seen that, as in the case of California, a strong emphasis is placed on AMI solutions and consumer-oriented technologies. This focus on the consumer and DSM is driven by three main factors: the need to reduce non-technical losses, implement demand flexibility mechanisms to face scarcity periods, and enhance energy efficiency (including low income consumers). Concerning MV grid operation, the most sought functionalities are fault location and isolation with the aim of improving reliability, as well as advanced control of existing voltage control devices (capacitors and regulators).

Note that DG is present in most demonstrators. However, the orientation given in this case tends to be different from Europe or California. Instead of testing solutions to integrate existing DG more efficiently as in the latter, the main goal is to deploy DG so as to supply local load in a more sustainable way, i.e. it is deployed as a solution rather than seen as a challenge. Likewise, EVs are mainly seen as a solution for sustainable urban mobility. Lastly, energy storage is tested, but it is not given as much relevance as in California or several of the GRID4EU demonstrators.

[47] http://www.aneel.gov.br/area.cfm?idArea=75
[48] http://redesinteligentesbrasil.org.br/

# 4.3 Comparative analysis: identification of non-technical barriers and drivers

*Distribution regulation*

According to the regulatory barriers identified in gD3.5, California and Brazil, in principle, do not present the most favourable conditions for upscaling and replication of smart grid solutions. On the one hand, the Californian regulation of distribution utilities can be seen as a cost of service regulation, which in theory provides distribution companies with little incentive to gain in efficiency. The existence of a three-year regulatory lag may provide utilities with some incentive to reduce their costs and seek for more cost-efficient solutions. However since any cost reduction would be offset by the regulator after three years, utilities may in the end see little incentives to reduce CAPEX or OPEX, thus representing a barrier mainly for use cases aiming to avoid or defer network investments.

It is argued below that the mandate to develop DRPs by IOUs may counteract this disincentive. Moreover, on-going regulatory reforms in other states, being New York the most noteworthy case (New York DPS 2014; New York DPS 2015), if successfully implemented, may act as a facilitator for a future regulatory change in California. An advantage of California in this regard, is that some form of forward-looking cost assessment is already being used during rate cases since utilities must present their business plans for the next few years. The future challenge is how to incorporate smart grid technologies into the utility plans and whether the regulator may be able to assess the efficiency and effectiveness of such plans so as to ensure they are cost-efficient.

On the other hand, Brazilian regulation resembles the approach followed in several EU countries. Efficient levels of OPEX are determined through backward-looking benchmarking techniques on the basis of historical information. Alternatively, CAPEX are subject to an input-oriented regulation consisting in the estimation of the replacement cost of existing assets, which encourages distribution companies to reduce unit costs (and to maintain depreciated assets in operation[49]), but not to reduce the overall investments. Once again, the separate treatment of CAPEX and OPEX is a barriers for smart grid solutions aiming at deferring distribution investments and increasing hosting capacity of existing grids. In this case, this is worsened by the deep connection charges that DG units must pay in Brazil.

As discussed below, price cap regulation, as present in Brazil, discourages distribution companies to facilitate net-metering and energy efficiency as both reduce the volume of energy distributed and consequently the firms' revenues. Notwithstanding, this effect is mitigated by the fact that the X factor incorporates adjustments for variation in the amount of electricity and number of consumers supplied by each company affected by the corresponding economies of scale factors (ANEEL 2015e). These factors represent the variation of distribution costs driven by a change in the number of customers of volume of electricity supplied.

---

[49] The use of book values and accounting methods to determine the RAB would encourage companies to replace depreciated assets so as to increase the rate base again. On the contrary, replacement costs deter asset substitution since companies are remunerated for all network assets in operation even if these have been fully depreciated.

*Performance indicators and regulation*

The main output indicators used in distribution regulation in the contexts under evaluation are those related to network reliability. Both in Brazil and California, regulatory mechanisms are in place to encourage utilities to control the average levels of continuity of supply as well as the worst-served customers. Average levels of reliability are controlled for by means of bonus-malus incentive schemes as it is common practice in European countries (California) or through a quality component embedded into the X factor that updates annual allowed prices during the regulatory period (Brazil), as done, for instance, in The Netherlands (Niesten 2010). On the other hand, quality of service in worst-served areas are addressed either through individual compensations similarly to European countries (Brazil) or by ranking distribution feeders and setting incentives based on the reliability levels measured for the ten worst-served feeders.

In principle, the existence of these incentives and the fact that reliability levels observed in the case of several distribution companies in these regions are comparatively worse than in EU countries (especially in Brazil) are relevant drivers for the replicability of MV automation solutions. However, this comparisons ought to be handled with care since the reported values for SAIDI and SAIFI across countries are not totally equivalent due to differences in the index definitions and measuring procedures: treatment of major events, threshold to define a fault as long or sustained, etc. In any case, the interest of utilities in both Brazil and California is proven by the fact that the on-going demonstration projects place a strong emphasis of these functionalities, as well as OMS upgrades.

The review of regulatory conditions in GRID4EU countries also analyzed in detail the existence of incentive schemes promoting loss reductions. Since utilities in Brazil and California are not fully unbundled, contrary to their European peers, these companies should have a natural incentive to reduce losses. However, this incentive disappears when loss purchases are fully passed-through to the tariffs. This can be prevented through mechanisms such as the one implemented by the Brazilian regulator, through which only a reference level is passed-through. Therefore, distribution companies are encouraged to reduce losses below this level. However, the normally low level of energy prices in Brazil, except for dry years, dilute the power of this scheme. In principle, this should not be a major drawback as wholesale prices reflect the real value of electric losses. However, since in the case of Brazil a significant share of them correspond to non-technical losses, this can have important implications for the financial situation of the power system and raise equity concerns.

Lastly, the tight voltage requirements and the existence of economic penalties, can be an incentive to implement advanced voltage control solutions as in demo 4 or demo 6 in Brazil. Note that a voltage drop or rise of 10%, which in some European countries may be deemed acceptable, would be considered as a critical situation that may not occur more than 0.5% of the time at risk of being penalized. Additionally, that fact that voltage rise limits are more stringent than voltage drop bounds, is a further driver for the implementation of advanced voltage control solutions (if DG penetration levels in Brazil grow over the next years, from the currently very low levels).

*Incentives for innovation and smart grid demonstration projects*

The previous description of the Californian and Brazilian contexts showed that distribution companies are active in demonstration activities in both cases. Similarly to the situation in the EU, this is mostly due to input-oriented incentives managed by policy-makers and regulators. At the moment, the large-scale roll-out of smart grid solutions may not be considered to have started, particularly in Brazil where the first demonstration projects have just been finalized and these have only involved a relatively small number of the distribution companies present in the country. An added barrier for replicability and scalability is that in both regions, there is a large number of small distribution companies which may not have the expertise and resources required to drive the transition towards a smarter distribution grid. Nonetheless, the fact that the utilities involved in these demonstration programs are subject to information disclosure and knowledge sharing obligations is a driver for upscaling and replication.

*Smart metering deployment*

Smart metering is an enabling technology for use cases related to LV supervision and demand response. Therefore, these types of use cases may be hampered by non-technical aspects that act as barriers to the large-scale roll-out of smart meters. Examples of such barriers can be found in both of the non-EU regions analyzed in this report. On the one hand, despite the fact that a large-scale roll-out of AMI has already been carried out in California (driver), the regulator had to introduce an opt-out clause due to public opposition to smart meters driven by health and privacy concerns. So far, the drop-out rates have remained low (0.65% state-wide). Nonetheless, this shows the importance of public perceptions and stakeholder engagement.

On the other hand, the Brazilian regulator decided to go for an opt-in policy, which may result in lower adoption rates as pointed out in (SC3 2014) on the basis of actual experiences. Furthermore, the Brazilian deployment is so far stagnated due to the on-ongoing process of technical requirements definition which creates uncertainties over its deployment. This even forced the regulator to delay its initial roll-out plans. These barriers are particularly relevant for Brazil due to the dire need of reducing non-technical losses (LV supervision is an enabling technology to plan and implement loss-reduction strategies) as well as to resort to demand response so as to face critical scarcity periods. The fact that critical periods in Brazil vary on a seasonal basis and depend on rather irregular weather-climate events (“El Niño”), makes dynamic critical peak pricing, which requires smart metering, more relevant than fixed ToU tariffs, which may be implemented with conventional metering systems.

A major difference of California and Brazil with respect to EU countries is that metering data management and deployment responsibilities are not a major issue. Distribution companies in these countries are vertically integrated distribution utilities, active in the supply and generation sectors. Moreover, the implementation of competitive retail markets (including LV consumers) is not a major policy goal as most consumers are captive, being supplied by the distribution utility operating the area they are located in. Therefore, contrary to the European context, there is little discussion about the fact that the distribution companies are responsible for metering deployment, reading and data management.

*RES support mechanisms and DG integration*

This report has shown that neither Brazil nor California are essentially different from EU countries, in the sense that support mechanisms for RES are the main driver for the connection of DG. The design and implementation of these mechanisms can determine both the technologies that are deployed as well as the sizes and locations in which these are installed. The existing RPS (California) and long-term auctions (Brazil) tend to promote large generation units over MV and LV DG. Nonetheless, alternative support schemes are in place in both cases, namely FITs and net-metering. The previous gD3.5 paid particular attention to self-consumption due to their importance with respect to raising customer awareness and demand response as well as the potential missing money problem created by net-metering and non-cost-reflective tariffs.

Because of this last drawback, distribution companies may oppose the development of DG through net-metering and self-consumption, particularly when they are part of a vertically integrated utility which incurs in losses both from the reduced network tariff collection and the loss of generation revenues. In fact, the neighbouring State of Nevada has recently modified its tariff structure so as to deter net-metering, raising complaints from the PV industry and environmentalists[50]. This may happen as well in California in the coming future, albeit it has been ruled out by the CPUC.

Furthermore, the financial health of the distribution business can be jeopardized when revenues depend on the amount of energy metered. California and Brazil present two different regulatory designs showing distinct consequences in this regard. On the one hand, the implementation of revenue decoupling in California, even before restructuring and liberalization, ensures that utilities are not exposed to this risk. On the other hand, Brazil follows a price-cap regulation which effectively exposes utilities to such risks, although these are limited due to the correction done on the X factor based on variations of the energy distributed as described in section 4.2.

The drawbacks of net-metering can become a major concern in both California and Brazil as DG penetration increases for the following reasons: the expiration of the credits generated by production surpluses is very long (unlimited in the case of California, and 36 months in Brazil), no demand charges that could help recover fixed system costs apply to small consumers, community or virtual net-metering is in place in both contexts, there is a significant potential for solar technologies. So far only partial solutions have been implemented such as caps on the installed capacity (California) and minimum bills (California and Brazil). Moreover, the existence of a long netting interval, in addition to being economically inefficient, creates barriers for demand response and residential storage. Hence, transitioning to shorter netting intervals and advanced tariff schemes and more cost-reflective network charges would facilitate the diffusion of these smart grid solutions.

Concerning smart grid solutions aiming to integrate DG efficiently into the MV network (voltage control, network reconfiguration), the DRPs mandated by the regulator in California are a clear enabler for such solutions. On the one hand, they encourage distribution companies to think ahead the best approach to connect and integrate DER at the least cost. On the other hand, they set information disclosure obligations on distribution utilities so that DG promoters may make better informed connection requests. However, information disclosure may be hampered by security and network integrity concerns. Whilst distribution components are not as critical individually as transmission assets, for example regarding possible large-scale black-outs, making public potential grid weak spots may enable criminal attacks. In the end, there is a trade-off between transparency and efficiency, and security. This compromise is a big concern in the US, which is not as prominent in Europe or in Brazil.

### *Islanding and microgrids*

Section 4.1 showed that islanded operation and microgrids are a hot topic in California, and the

[50] http://cleantechnica.com/2016/01/18/black-hole-forms-solar-net-metering-nevada/
http://www.energymanagertoday.com/nevada-puc-hikes-costs-for-commercial-residential-rooftop-solar-0121119/

whole US. This interest is driven by a strong focus on network resiliency and reliability. In the Eastern coats of the US, this is largely driven by extreme weather conditions (storms) which periodically affect this region. However, this is not a major issue in California, where concerns about terrorist attacks and sabotage on sensitive loads (e.g. universities, prisons or military bases), are the main aspects that make microgrids and islanded operation appealing.

Nonetheless, significant differences exist with respect to the framework in which GRID4EU islanding use cases were developed. In this project, the islanded area was part of the distribution grid and the islanding was performed and controlled directly by the DSO, comprising several loads and DG units metered separately, i.e. what (Marnay et al. 2011) refer to as a utility microgrid or milligrid. On the contrary, the focus in California is on setting up microgrids at the premises of a single consumer from the utility's point of view, i.e. what (Marnay et al. 2011) refer to as a customer microgrid or true microgrid. The technological solution tested within GRID4EU could be applicable in both cases. However, the regulatory implications of both approaches are completely different. In fact, the potential regulatory barriers for customer microgrids are much more easily overcome, thus being this a replicability driver for the case of California.

Regarding microgrid deployment in Brazil, this may be enabled by the fact that regulation already considers the possibility of islanded operation for units above 300kW and mandates them to have voltage and frequency control capabilities. However, there is not a clear framework setting up the conditions (obligations, remuneration, etc.) under which DG units would provide this services to the distribution utility, thus facing similar barriers identified in gD3.5 for European countries.

An additional type of microgrid, besides utility and customer microgrids, is that of isolated systems which permanently operate independently of the main grid. This typically happens in isolated rural areas or in actual islands. This could be seen as a solution for certain areas in Brazil. However, this potential is rather limited since the degree of access to electricity supply in this country is of 99.5% (2012), according to data from the World Bank[51]. For the sake of comparison, the value of this indicator stands at 96.4% across Latin American and Caribbean countries and 84.6% worldwide according to the same source. Therefore, microgrid implementation in Brazil would be limited to actual islands or very specific rural areas.

Some of the countries where microgrids completely isolated from the rest of the power system could be, for example, India[52] or Peru[53] where viable business models already exist for remote rural communities for which grid extension would be too expensive. According to (OSINERGIM 2009), more than 20% of the Peruvian population did not have access to electricity supply (reaching up to more than 50% in some regions). Likewise, the situation in India makes microgrids and islanded operation relevant since, according to (IEA 2012), 289 million people did not have electricity access in 2009, whilst in many rural areas, even with electricity supply, this is very unreliable power (EBTC-ARE 2015). Furthermore, the precarious financial situation of many Indian distribution utilities hampers grid expansion, making microgrids an attractive, if not the only, solution nowadays. Nonetheless, in the case of isolated systems, the islanded operation ought to be planned jointly with generation resources so as to ensure that enough energy is available when

[51] http://data.worldbank.org/indicator/EG.ELC.ACCS.ZS/countries/1W-ZJ-BR?display=default
[52] http://news.mit.edu/2016/tata-researchers-tackle-rural-electrification-0121
[53] http://www.acciona.com/sustainability/society/acciona-microenergia-foundation/
http://www.selco-india.com/

needed, especially when batteries, which by definition are energy-bounded, are used as the island main controller.

### *Other non-technical boundary conditions*

In addition to the specific regulatory issues previously discussed within this section, there are several other non-technical boundary conditions that may affect the scalability and replicability potential of GRID4EU solution in California and Brazil.

Unbundling rules allowing for vertical integration have been pointed out to be a barrier for well-functioning and competitive retail markets at all levels. However, this is not a policy priority in Brazil or California at the moment, where most small consumers are still captive and supplied by the corresponding distribution utility. As mentioned above, the advantage of this approach is that AMI deployment models and demand response are greatly simplified, being a driver for upscaling and replication. The main drawback is the lack of choice of end consumers as they would have to stick to the tariff options offered exclusively by their distribution company.

The same topic is relevant for the deployment storage, which is facing significant barriers in Europe due to the unbundling rules (besides the cost-related ones). The fact that regulatory barriers for storage are not as stringent in such contexts is proven by the recently implemented Californian storage program, where utilities are given a central role in the deployment of storage at commercial scale. Grid applications if this technology are much simpler to implement as the utility may own and operate the installations, albeit it is still unclear whether the business case for storage relying only on distribution services is a viable one. Hence, complementary solutions either enabling third-parties to provide service to the distribution company or to allow these to use the distribution-owned batteries for services such as balancing or price arbitrage would still be presumably needed.

Moreover, it is relevant to mention that several European companies have acquired distribution companies in Brazil and US (even though not in California), such as Enel (formerly Endesa), EDP or Iberdrola. This fact could represent a positive enabling factor for the replicability of the smart grid solutions tested in Europe, as DSOs can leverage from the lessons learnt. In fact, several distribution companies owned by European firms are among the list of firms that have carried out demonstration projects in Brazil[54].

[54] http://redesinteligentesbrasil.org.br/projetos-piloto-brasil.html

# 5 Conclusions and lessons learnt

Previous work within the GRID4EU project, evaluated the effect of different boundary conditions on the potential for upscaling and replication of the tested use cases focusing on the 6 demo countries, namely: Germany, Sweden, Spain, Italy, Czech Republic and France. One of the lessons learnt from such an exercise was that, despite the fact that DSO size or ownership may vary greatly across Europe, the characteristics of distribution networks and operational approaches are relatively homogeneous across European countries. Therefore, the SRA results could be broadly applicable on a wider European context, provided the relevant parameters identified are considered.

However, the applicability of the GRID4EU SRA rules to non-EU contexts, where the boundary conditions may be significantly different, could be more challenging. Addressing this concern, this report has evaluated the extent to which the aforementioned rules could be applied to other contexts. In order to perform such an analysis, two regions have been selected; the state of California (US) and Brazil. Both regions are active in terms of RES integration and smart grid deployment. Additionally, their distribution sectors and regulatory frameworks are distinctly different both among them and when compared to the European countries for which the SRA rules were developed. This provided suitable conditions for a wider analysis of the applicability and limitations of these rules.

A comparative assessment between GRID4EU countries and the selected regions was performed, attending to the most relevant boundary conditions, i.e. those with a stronger impact on the KPIs. This comparison has allowed obtaining qualitative indications of the potential impact and suitability of GRID4EU solutions in Brazil and California. The assessment of the upscaling and replicability potential has been divided into two subsequent steps: i) evaluation of the effect of technical boundary conditions related to distribution networks and ii) characterization of non-technical boundary conditions related to regulatory frameworks and stakeholders aspects. The main conclusions drawn from each of these two steps are summarized on the ensuing.

*Upscaling and replication: technical boundary conditions*

A detailed analysis of the technical boundary conditions has been carried out for both California and Brazil, comprising: distribution grid characteristics, performance indicators (continuity of supply, energy losses), smart metering status, and installed DG. These parameters have been compared with the data compiled from the GRID4EU demo countries. It has been shown that distribution networks in California and Brazil are quite different from European ones, particularly with respect to the design of LV networks. For instance, in Brazil and California, contrary to European countries, there are no secondary substations as such. Instead, distribution transformers, much smaller in size, switchgear and protection equipment are spread throughout the network. The implications of this and other differential features are manifold concerning GRID4EU uses cases implementation:

- **Demand response:** unlocking demand flexibility is a major target both in California and Brazil thus being GRID4EU solutions in this respect widely replicable. The situation in California can be considered to be similar to many European countries since this region is facing a growing penetration of intermittent generation in a system based on thermal generation. On the contrary, Brazil is already a quite flexible system since it is based mostly on hydro power. However, scarcity periods may occur during dry years, when demand response, e.g. in the form of critical peak pricing, could significantly alleviate the need for additional capacity.

- **Voltage/load control in MV to increase NHC:** current moderate DG penetration in MV does not presumably cause major voltage problems at the moment. In fact, relays preventing reverse power flows are deployed in California. However, the hosting capacity of MV networks in Brazil and California can be expected to be lower than in GRID4EU countries due to the generally lower rated voltages, longer feeders, higher R/X ratios and tighter voltage limits (which are well below the 10% stipulated in standard EN50160). Therefore, voltage control strategies may gain in relevance and replicability potential. In this regard, in both contexts analyzed, the presence of OLTCs and voltage regulators, capable of correcting the voltage in case of unbalanced feeders outgoing of the same substation, render DG power factor control less attractive than in the EU.
- **Voltage/load control in LV to increase NHC:** DG penetration in the LV is very low in Brazil nowadays. Hence, the need for this use case is not foreseen in the short to medium term. However, since this country presents long three-phase LV lines this conclusions may need to be revisited if small-scale DG grows significantly in order to tackle both phase unbalances and voltage issues. On the other hand, LV DG is already widespread in California. However, since LV lines are very short and single-phase, this use case is not a priority for distribution utilities.
- **Distribution automation:** this type of smart grid solution presents a significant potential in MV urban networks, both in Brazil and California. In these areas, the distribution network is meshed and could be reconfigured, as proven by the several ongoing demonstration projects. However, the SRA rules and the definition of the degree of automation developed for EU countries are not directly applicable due to the different network designs. Instead of at secondary substations, automation points would be placed at the NO switches that connect neighbouring feeders. Thus, new indicators and simulations may be needed so as to infer quantitative rules.
- **LV supervision:** this functionality is not very relevant for California owing to the fact that LV networks are very short and connect a very low number of consumers. Moreover, load unbalance correction would not make sense since Californian LV grids are usually single-phase. On the contrary, LV supervision presents a significant replicability potential in Brazil, not because of unbalances as DG penetration is rather low, but because of the extremely high levels of losses. Thus, LV monitoring could support distribution companies in their cost reduction efforts. Nonetheless, the communications architecture may need adaptations in response to: different network topology, highly scattered population and communications availability in remote areas.
- **Anti-islanding:** the current potential for this solution is quite limited in Brazil, owing to the little presence of PV in the MV network. On the contrary, there is an actual concern about this issue in California and a significant potential in the medium term. Current DG penetration levels are still moderate. However, utilities are already evaluating the use of communications-based disconnection systems to face higher penetrations of DG.

*Upscaling and replication: non-technical boundary conditions*

As a complement to the previous technical evaluation of the replicability potential of GRID4EU solutions, the barriers and drivers posed by non-technical boundary conditions have been explored for California and Brazil. The focus was mainly placed on the differential regulatory settings in these regions as compared to the EU context. The topics analyzed included: distribution regulation, smart meter deployment, RES promotion policies, self-consumption, energy storage, incentives for smart grid demonstration projects and treatment of DG units. Additionally, some noteworthy stakeholder issues have been discussed. The main lessons learnt from this analysis are the following:

- **Distribution regulation:** current regulatory frameworks in these regions provide distribution companies with virtually no incentive to defer investments, either because of a cost of service regulation (California) or, similarly to several EU countries, due to a separate treatment of CAPEX and OPEX under incentive regulation (Brazil). Thus, several smart grid solutions may be hampered. Notwithstanding, the Californian framework may be more easily adapted in the short-term since distribution utilities are already required to perform forward-looking business plans, which need to explicitly consider the presence of DER.

- **Performance indicators:** the existence of incentives to improve continuity of supply levels in both regions, together with the relatively poor quality levels (especially in some areas of Brazil), are important enablers for MV automation. On the other hand, energy losses are seen as a major concern in Brazil, particularly non-technical ones. Nevertheless, despite the fact that distribution companies are indeed encouraged to reduce these losses, the very low market prices for most of the time dilutes the power of these incentives, thus being a barrier for LV supervision replication. Lastly, the stringent voltage limits and financial penalties faced by Brazilian firms can be a potential driver for voltage control functionalities if DG penetration increased in the future.

- **Smart metering deployment:** barriers to the deployment of smart meters, necessary for LV supervision and demand response, can be found in both non-EU regions. A large-scale roll-out of AMI has already been carried out in California. However, an opt-out clause was introduced as a result of public concerns about health and privacy. On the other hand, the opt-in policy adopted in Brazil usually results in lower adoption rates. Moreover, the roll-out has stagnated due to the existing uncertainties on technical requirements. On the plus side (for smart meters), distribution companies in both regions are vertically integrated. Hence, contrary to the European context, there is no discussion about the fact that these companies are responsible for meter deployment, reading and data management.

- **Islanding and microgrids:** islanding solutions present an important replicability potential in California in the form of microgrids at the premises of sensitive loads, driven by security and resiliency concerns. In fact, since the focus is placed on consumer microgrids instead of utility microgrids, as in GRID4EU demos, the potential regulatory barriers would be much more easily overcome. On the other hand, microgrids for the electrification of remote areas show a limited potential since both California and Brazil present very high degrees of electrification.

- **Unbundling:** as mentioned above, Californian and Brazilian distribution companies are vertically integrated. This is not seen as a major concern since a competitive retail market is not a policy priority at the moment. This fact simplifies AMI deployment models and demand response schemes, although these become fully subject to the willingness of the incumbent utilities. Likewise, storage-based solutions, which in Europe are hindered by unbundling rules (besides economic reasons), are more straightforward as the utility may own and operate the installations.

# 6 References

## 6.1 Project Documents

gD3.1. GPW3 Methodology: Methodology for the definition of scaling-up and replication rules and cost-benefit analysis. 31st October 2014.

gD3.2/gD3.3. Technical SRA: Technical scalability and replicability analysis of relevant use cases. Methodology and application. 31st October 2014.

gD3.2b. Report on relevant regulatory schemes for smart grid solutions. 31st January 2015.

gD3.4. Technical Scalability and Replicability Analysis of the GRID4EU Demos. Simulation Results for the GRID4EU demonstrations. 31st January 2015.

gD3.5. Scalability and Replicability Rules. Scaling-up and replication rules of the GRID4EU demonstration as inferred from the SRA studies. 31st January 2015.

## 6.2 External documents

ABRADEE (2015) "Evolução dos Dados de Consumidores e Consumo." 08/04/2015. http://www.abradee.com.br/setor-de-distribuicao/banco-de-dados/comercial.

Ampla (2014). Projeto Cidade Inteligente Búzios. Workshop ANEEL Reedes Inteligentes. April 16, 2014. Brasília.

ANEEL (2008) "Intruções para Elaboraçâo e Envio de Arquivos para Cadastro no Sistema de Gestâo de P&D ANEEL - Programa de Pesquisa e Desenvolvimento Tecnológico do Setor de Energia Elétrica." Agência Nacional de Energia Elétrica – ANEEL, Brasília, September 2008.

ANEEL (2010a) "Chamada Nº 011/2010. Projeto Estratégico: "Programa Brasileiro de Rede Elétrica Inteligente"." Agência Nacional de Energia Elétrica – ANEEL, Brasília, July 2010.

ANEEL (2010b) "Procedimentos de Distribução de Energia Elétrica no Sistema Elétrico Nacional - PRODIST. Módulo 5 – Sistemas de Medição." Agência Nacional de Energia Elétrica – ANEEL, Resolução Normativa nº 424/2010.

ANEEL (2012a) "Procedimentos de Distribução de Energia Elétrica no Sistema Elétrico Nacional - PRODIST. Módulo 3 – Acesso ao Sistema de Distribuição." Agência Nacional de Energia Elétrica – ANEEL, Resolução Normativa nº 517/2012 14/12/2012.

ANEEL (2012b) "RESOLUÇÃO NORMATIVA Nº 482, DE 17 DE ABRIL DE 2012. Estabelece las condições gerais para o acesso de microgeração e minigeração distribuída aos sistemas de distribuição de energia elétrica, o sistema de compensação de energia elétrica, e dá outras providências." Agência Nacional de Energia Elétrica, April 17, 2012.

ANEEL (2012c) "Resolução Normativa Nº 502, de 7 de Agosto de 2012. Regulamenta sistemas de medição de energia elétrica de unidades consumidoras do Grupo B." Agência Nacional de Energia Elétrica, August 7, 2012.

ANEEL (2014) "Resultados da Audiência Pública 93/2013, que visou obter subsídios para a revisão dos Módulos 6 e 8 dos Procedimentos de Distribuição – Prodist, motivada pela inclusão dos sistemas de medição de que trata a Resolução Normativa no 502, de 2012, e a alteração dessa com vistas à adequação dos prazos normativos por ela estabelecidos." Agência Nacional de Energia Elétrica, February 11, 2014.

ANEEL (2015a) "Módulo 2: Revisão Tarifária Periódica das Concessionárias de Distribuição. Submódulo 2.1 -

Procedimientos Gerais." Agência Nacional de Energia Elétrica, Resolução Normativa nº 686/2015, de 23/11/2015.

ANEEL (2015b) "Módulo 2: Revisão Tarifária Periódica das Concessionárias de Distribuição. Submódulo 2.2 - Custos Operacionais e Receitas Irrecuperáveis." Agência Nacional de Energia Elétrica, Resolução Normativa nº 660/2015, de 28/04/2015.

ANEEL (2015c) "Módulo 2: Revisão Tarifária Periódica das Concessionárias de Distribuição. Submódulo 2.3 - Base de Remuneração Regulatória." Agência Nacional de Energia Elétrica, Resolução Normativa nº 686/2015, de 23/11/2015.

ANEEL (2015d) "Módulo 2: Revisão Tarifária Periódica das Concessionárias de Distribuição. Submódulo 2.4 - Custo de Capital." Agência Nacional de Energia Elétrica, Resolução Normativa nº 648/2015, de 3/2/2015.

ANEEL (2015e) "Módulo 2: Revisão Tarifária Periódica das Concessionárias de Distribuição. Submódulo 2.5 - Fator X." Agência Nacional de Energia Elétrica, Resolução Normativa nº 660/2015, de 28/04/2015.

ANEEL (2015f) "Módulo 2: Revisão Tarifária Periódica das Concessionárias de Distribuição. Submódulo 2.6 - Perdas de Energia." Agência Nacional de Energia Elétrica, Resolução Normativa nº 660/2015, de 28/04/2015.

ANEEL (2015g) "Procedimentos de Distribução de Energia Elétrica no Sistema Elétrico Nacional - PRODIST. Módulo 2 – Planejamento da Expansão do Sistema de Distribuição." Agência Nacional de Energia Elétrica – ANEEL, Resolução Normativa nº 655/2015.

ANEEL (2016a) "Procedimentos de Distribução de Energia Elétrica no Sistema Elétrico Nacional - PRODIST. Módulo 7– Cálculo de Perdas na Distribuição." Agência Nacional de Energia Elétrica – ANEEL, Resolução Normativa nº 656/2015. 15/04/2015.

ANEEL (2016b) "Procedimentos de Distribução de Energia Elétrica no Sistema Elétrico Nacional - PRODIST. Módulo 8 – Qualidade da Energia Elétrica." Agência Nacional de Energia Elétrica – ANEEL, Resolução Normativa nº 664/201.

ANSI (2011) "ANSI C84.1-2011. American National Standard For Electric Power Systems and Equipment — Voltage Ratings (60 Hertz)." American National Standards Institute, Inc., ANSI C84.1-2011. Revision of ANSI C84.1 - 2006.

Arritt, R. F. and R. C. Dugan (2010). The IEEE 8500-node test feeder. Transmission and Distribution Conference and Exposition, 2010 IEEE PES.

Barroso, L. (2015). The Brazilian Energy Sector. Master in the Electric Power Industry. Comillas University. Madrid, Spain.

Batlle, C. and L. Barroso (2011). "Review of support schemes for renewable energy sources in South America." IAEE Newsletter Third Quarter: 27-31.

Brito, R. G. d. C., F. C. Andrade, E. Sakiyama and L. E. F. D. Jr (2015) "Geração Distribuída no Brasil: panorama, barreiras e oportunidades." COGEN - Brazilian Association of Co-generation, http://www.cogen.com.br/paper/2015/GDartigo_02_06_2015.pdf.

CEER (2012) "5th CEER benchmarking report on the quality of electricity supply."

CEER (2013) "CEER Benchmarking Report 5.1 on the Continuity of Electricity Supply. Data update." Ref: C13-EQS-57-03. 19 December 2013.

Cemig (2014). Projeto Cidades do Futuro Convênio D423 – Cemig D. Workshop ANEEL Reedes Inteligentes. April 16, 2014. Brasília.

Cohen, M. A., P. A. Kauzmann and D. S. Callaway (2015) "Economic Effects of Distributed PV Generation on California's Distribution System." Energy Institute at Haas. University of California at Berkeley, EI @ Haas WP

260. June 2015.

CPFL (2006). CPFL Energia - Encontro com Investidores. Campinas, 07 de Dezembro de 2006.

CPUC (2012a) "CPUC approves analog meter options for Edison and SDG&E customers who do not wish to have a wireless smart meter." California Public Utilities Commission, PRESS RELEASE. Docket #: A.11-07-020. A.11-03-015. February 1, 2012.

CPUC (2012b) "CPUC approves analog meters for PG&E customers electing to opt out of smart meter service." California Public Utilities Commission, PRESS RELEASE. Docket #: A.11-03-014. April 19, 2012.

CPUC (2013a) "Decision adopting energy storage procurement framework and design program." California Public Utilities Commission, Decision 13-10-040. Date of Issuance 10/21/2013.

CPUC (2013b) "Decision adopting joint standard contract for section 399.20 feed in tariff program and granting, in part, petitions for modification of decision 12-05-035." California Public Utilities Commission, Decision 13-05-034. Date of Issuance 05/30/2013.

CPUC (2014) "Annual Report to the Governor and the Legislature California Smart Grid per Senate Bill 17 (Padilla, 2009)." California Public Utilities Commission, January, 2015. Available at: http://www.cpuc.ca.gov/General.aspx?id=4693.

CPUC (2016) "California Smart Grid Annual Report to the Governor and the Legislature in Compliance with Public Utilities Code 913.2." California Public Utilities Commission, January, 2016. Available at: http://www.cpuc.ca.gov/General.aspx?id=4693.

EBTC-ARE (2015) "The India Off-grid Electricity Market - Policy Framework, Players and Business Opportunities." European Business and Technology Centre - Alliance for Rural Electrification,

ERGEG (2008) "Treatment of losses by network operators. ERGEG position paper for public consultation. E08-ENM-04-03." E08-ENM-04-03.

European Commission (2014a) "Commission staff working document: Cost-benefit analyses & state of play of smart metering deployment in the EU-27." SWD(2014) 189 final. Brussels, 17.6.2014.

European Commission (2014b) "Commission staff working document: Country fiches for electricity smart metering." SWD(2014) 188 final final. Brussels, 17.6.2014.

European Commission (2014c) "Report from the Commission: Benchmarking smart metering deployment in the EU-27 with a focus on electricity." COM(2014) 356 final.

IEA (2012) "Understanding Energy Challenges in India - Policies, Players and Issues."

KEMA Consulting GmbH (2011) "Memo: Distributed Generation in Europe – Physical Infrastructure and Distributed Generation Connection." April 29, 2011.

Kersting, W. H. (1991). "Radial distribution test feeders." Power Systems, IEEE Transactions on 6(3): 975.

Lima, J. W. M., J. C. C. Noronha, H. Arango and P. E. S. dos Santos (2002). "Distribution pricing based on yardstick regulation." IEEE Transactions On Power Systems 17(1): 198-204.

Marnay, C., B. Nordman and J. Lai (2011) "Future Roles of Milli-, Micro-, and Nano- Grids." Ernest Orlando Lawrence National Berkeley Laboratory, LBNL - 4927E.

Mastropietro, P., C. Batlle, L. Barroso and P. Rodilla (2014). "Electricity auctions in South America: Towards convergence of system adequacy and RES-E support." Renewable and Sustainable Energy Reviews 40: 375-385.

Maurer, L. (2009). Tariff Schemes to foster demand response, energy efficiency and demand side management. International Seminar on Elecricity Tariff Structure. Brasilia, Brazil. 17-18 June, 2009, ANEEL.

Morgan, P. (2013) "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations." Graceful Systems LLC, Revised February 2013.

Mota, R. L. (2004) "Comparing Brazil and USA Electricity Distribution Performance: What was the Impact of Privatisation?" CWPE 0423 & CMI Working paper 39 1027,

New York DPS (2014) "Reforming the Energy Vision. NYS Department of Public service Staff Report and Proposal." State of New York. Department of Public Service, CASE 14-M-0101. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. April 24, 2014.

New York DPS (2015) "Staff White Paper on Ratemaking and Utility Business Models." State of New York. Department of Public Service, CASE 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. July 28, 2015.

Niesten, E. (2010). "Network investments and the integration of distributed generation: Regulatory recommendations for the Dutch electricity industry." Energy Policy 38(8): 4355.

ONS (2010) "Submódulo 3.6 Requisitos técnicos mínimos para a conexão às instalações de transmissão." Operador Nacional do Sistema Elétrico, Despacho SRT/ANEEL nº 2744/10. 15/09/2010.

OSINERGIM (2009). White paper on the regulatory framework for electricity distribution in Peru (in Spanish). OSINERGIM - Organismo Supervisor de la Inversión en Energía y Minas, Original title: "Libro Blanco del marco regulatorio de la distribución eléctrica en el Perú".

PacifiCorp (2015). Electric System Reliability Reporting. CPUC Workshop I on Reliability Reporting. 24 April 2015.

PG&E (2015). Electric Distribution Reliability. CPUC Workshop II on Reliability Reporting. May 26 - 27, 2015.

Santos, W. C., L. G. G. P. Castro, R. A. Martins, N. S. D. Brito, B. A.Souza and M. B. R. Corrêa (2014). Modelagem e Validação de um Sistema de Distribuição Secundário via Simulações Computacionais no ATP e no OP5600 da OPAL-RT. V Simpósio Brasileiro de Sistemas Elétricos. Foz do Iguaçu – PR, Brasil. 22-25/04/2014.

SC3 (2014) "D3.4. Report on case analyses, success factors and best practices." Smart consumer, smart customer, smart citizen,

Schneider, K., Y. Chen, D. Chassin, R. Pratt, D. Engel and S. Thompson (2008) "Modern Grid Initiative. Distribution Taxonomy Final Report." Pacific Northwest National Laboratory, PNNL-18035. November 2008.

Schneider, K. P. and J. C. Fuller (2010). Voltage control devices on the IEEE 8500 node test feeder. Transmission and Distribution Conference and Exposition, 2010 IEEE PES.

SDG&E (2015). Electric Reliability Reporting. CPUC Workshop II on Reliability Reporting. May 26 - 27, 2015.

Silva, H. (2011) "Cost efficiency in periodic tariff reviews: the reference utility approach and the role of interest groups." Public Utility Research Centre, University of Florida,

US Congress (2009). American Recovery and Reinvestment Act of 2009: Washington, January 6th, 2009. Signed into Law on february 17 2009.

Whited, M., T. Woolf and A. Napoleon (2015) "Utility Performance Incentive Mechanisms: A Handbook for Regulators." Synapse Energy Economics, March 9, 2015.