Energy Technology and Governance Program:

South East European Distribution System Operators Connection of Distributed Generation to Distribution Networks: Recommendations for Technical Requirements, Procedures and Agreements

Sub-agreement No. USEA/USAID-2013-709-01

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South East European Distribution System Operators Connection of Distributed Generation to Distribution Networks: Recommendations for Technical Requirements, Procedures and Agreements

Prepared for:

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2 ACRONIMS AND ABBREVIATIONS

DG	distributed generation
DSO	distribution system operator
TSO	transmission system operator
CHP	co-generation
PP	power plant
RES	renewable energy source
DER	distributed energy resource
DR	distributed source
PV	photovoltaic
EPS	electric power system
PCC	point of common coupling
WPP	wind power plant
SPP	solar power plant
HPP	hydro power plant
NREAP	national renewable energy action plan
REAP	renewable energy action plan
RA	regulatory authority
MO	market operator
MS	EU Member State
OLTC	on-load tap changer
AVC	automatic voltage control
SEE	South East Europe
RAB	regulated asset base

3 TERMS OF REFERENCE

The last two decades have seen an unprecedented development of distributed renewable energy resources. Many countries have adopted a variety of incentives (feed-in tariffs, green certificates, direct subsidies, tax exemptions etc.) to promote renewable energy and distribution system operators are under increasing pressure to respond to an often excessive demand for access to the network, while at the same time ensuring network stability and continuity of service.

This study will assist the USAID / USEA Distribution System Operator Security of Supply Working Group member utilities to develop rules and requirements to properly evaluate and integrate new distributed renewable energy generation connection requests. The scope of the study is to:

- Survey the current rules governing the connection of new distributed generation in the DSO Working Group member countries (Albania, Bosnia & Herzegovina, Croatia, Kosovo, Macedonia and Serbia).
- Survey the current grid/distribution codes regarding generators (and/or other “equivalent” documents) of the DSO Working Group member countries.
- Review the current connection criteria (plant and system standards) applied in the countries for distributed generation including:
    - steady-state and short-circuit current constraints,
    - power quality,
    - voltage profile, reactive power and voltage control,
    - contribution to ancillary services,
    - protection aspects,
    - islanding and islanded operation,
    - system safety,
- Analyse the technical evaluation practices used for reviewing new connections and assessing the impact on the capacity capabilities of the grid.
- Analyse the performance obligations of distributed generation in the DSO Working Group member countries.
- Perform a technical assessment and comparative analysis of the different approaches in the region.
- Select a U.S. distribution system operator and provide an overview of their rules/requirements for integrating new distributed generation and their applicability in Southeast Europe.
- Conduct a training workshop on distributed generation interconnection best practices.
- Review opportunities to improve and harmonize connection rules in the region.

3.1 TASK 1A: Distributed Generation Connection Procedure Review

- Identify the main issues that should be considered with the integration of distributed generation on the distribution network in southeast Europe
- Prepare, harmonize and distribute questionnaires to Working Group DSOs covering all relevant issues regarding distributed generation connection
- Prepare detailed information for each participating DSO related to their distributed generation connection procedures (e.g. issuing the connection application, obligations, time span, validity period of the connection , denial of connection, user constraints),

- Prepare detailed information for each participating DSO related to rules and codes (i.e. technical aspects), and
- Prepare detailed information for each participating DSO related to connection tariffs and costs governing connection of distributed generation.

The project deadlines are given as follows:

- 2 weeks for preparation and distribution of the questionnaire,
- 3 weeks minimum for collecting the answers,
- 3 weeks for clarifications, amendments of the data and preparation of the overview.

Action	Date	Task Type
Prepare a summary overview and presentation for each working group member DSO detailing their responses to the questionnaires	3 weeks after questionnaire responses collection (expected on June 1, 2015)	Deliverable

3.2 TASK 1B: Recognition of Inadequacies in the Current Procedure and Recommendations for Improvements

- Summarize in a comparative manner the current connection criteria applied in the working group DSOs for distributed generation;
- Identify inadequacies in the current procedures and criteria;
- Survey the technical evaluation practices adopted by DSOs in the region (i.e. system studies done as part of new connection offer process by which capacity of the grid is assessed);
- Provide recommendations for technical requirements, procedures for new connection and agreements.

Action	Date	Task Type
Report summarizing and comparing the distributed generation connection procedures for Working Group DSOs and identifying inadequacies	6 weeks after the initial presentation and discussion (expected on July 15, 2015)	Deliverable

3.3 TASK 1C: Select a U.S. Distribution System Operator and Provide an Overview of their Rules/Requirements for Integrating New Distributed Generation and their Applicability in Southeast Europe

- Description of the rules for distributed generation in the selected U.S. DSO,
- Conduct a one-day training workshop to introduce working group member DSOs best practices of operating distribution networks that have a high degree of distributed generation

Action	Date	Task Type
One Day training workshop on distributed generation interconnection best practices	expected on September 30, 2015	Deliverable

TASK 1D: Preparation of Final Report

Action	Date	Task Type
Final Report	4 weeks after the workshop (expected on October 30, 2015)	Deliverable

4 INTRODUCTION

Since the beginning of the 1990's a substantial growth of distributed generation (DG) was experienced on power systems in many countries. This growth may be explained by several factors: changes in the institutional context (e.g. deregulation), progress in generation technologies, cost reduction in materials, and economic incentives (e.g. special purchase tariffs for electric energy produced by renewable energy sources, combined heat and power systems (CHP) or plants making use of waste).

As the activities are underway in the SEE region for creation of a beneficial investment climate for renewable energy producers, distribution system operators (DSO) will be under increasing pressure to respond to an often excessive demand for access to their networks. The connection of DG to the grid has given rise to new and sometimes challenging problems especially on distribution networks. Indeed these latter were not initially designed to host DGs. Different issues are at stake with the advent of DG on distribution networks:

- steady-state and short-circuit current constraints,
- power quality,
- voltage profile, reactive power and voltage control,
- stability and capability of DG to withstand disturbances,
- protection aspects,
- system safety,
- islanding and islanded operation,
- contribution to ancillary service,
- lack of reserve capacity to deal with intermittent generation (especially of wind and solar power plants).

Depending on the country, these issues may be more or less important or may be dealt with a rather different ways, since distribution networks may be quite different. Although in the observed region these differences may not that huge, due to the fact that till 1991 all of analysed DSOs except Albanian one were part of common ex-Yugoslavian power system, differences exist and generally include: voltage levels, configuration and architecture, characteristics, operation and protection practices, regulations, types of loads, among others. Other factors, such as political or socio-economic factors, may also play an important role in this field.

Judgement of investors and also other parties is that in most of SEE DSOs there is no adequate progress in newly installed capacities in the last few years. In this sense, the renewable targets are at risk of not being met. Burdensome access to the network for renewable energy projects remains one of the most critical issues. Therefore, progress is urgently required in the areas of transparency, consistency of network rules and grid connection issues. Network operators have to become more transparent towards the producers (besides customers) with regard to information on the estimated costs and timeframe for connections (i.e. lengthy procedures). It could be said that the complexity of the administrative set-up for authorization and permitting in is a cumbersome barrier in unlocking the great renewable energy sources (RES) potential present in the region.

Through the survey of the current rules governing the connection of new distributed generation in the DSO WG member countries, and the current grid/distribution codes requirements regarding generators, by reviewing of the current connection criteria applied for distributed generation, analysis of the technical evaluation practices used for reviewing new connections and assessing the impact on the capacity capabilities of the grid, analysis of the performance obligations of distributed generators in the DSO WG member countries, the project is targeted at:

- performing a technical assessment and comparative analysis of the different approaches in the region,

- providing an overview of selected U.S. DSOs rules/requirements for integrating new distributed generation and their applicability in SEE,
- actions needed to improve and harmonize connection rules in the region, and
- conducting a training workshop on distributed generation interconnection best practices.

The strategic objectives of the project are:

- to assist the SEE DSOs develop set of rules and requirements related to connection procedure. Namely, permitting, authorization and connection to the distribution grids procedures shall be more streamlined and coordinated amongst the institutions in charge, and
- to help DSOs in preparing for operation with increased integration of distributed generation. Namely, more electricity generated at distribution level, from renewable energy sources (RES), is requiring a system renovation in operation and regulation.

In this project have been involved all SEE DSO WG members (*Figure 4.1*) from 6 countries and 9 DSOs:

1. HEP ODS (Croatia) - *HEP – Operator distribucijskog sustava d.o.o.*,
2. EPBiH (BiH) - *JP Elektroprivreda BiH*,
3. EPHZHB (BiH) - *JP Elektroprivreda Hrvatske Zajednice Herceg-Bosne*,
4. ERS (BiH) - *JP Elektroprivreda Republike Srpske*,
5. EDB (BiH) - *JP Komunalno Brcko*,
6. EPS (Serbia) - *Elektroprivreda Srbije*,
7. KEDS (Kosovo) - *Kosovo Electricity Distribution and Supply*,
8. EVNM (Macedonia) - *EVN Macedonia,*
9. OSHEE (Albania) - *OSHEE Operatori i Shpërndarjes së Energjisë Elektrike sh.a.*.

Figure 4.1 SEE DSO WG members (9 DSOs)

4.1 Distributed generation

According to the EU Electricity Directive:

“distributed generation means generation plants connected to the distribution system”.

Each different type of distributed generation has its own technical and commercial characteristics. However, there are three typical characteristics that distinguish DG from centralised large-scale generation:

- Distributed generation is connected to the distribution network (usually at voltage levels of 110 kV and lower) and is often operated by independent power producers, often consuming a significant share of power themselves. The large-scale units are connected to high voltage grid levels and operated by incumbent utilities (sometimes a joint venture with a large industrial consumer). DG has, as it is connected to lower voltage networks, to cope with a number of specific network issues that are of less relevance to centralised generation capacity.
- A second distinction is the location of the electricity supply. DG is usually generated close to the source and not so close to the demand site. Especially wind power is usually generated remote from the more populated regions. The consequence is that wind power plants are connected to weak (low voltage) electricity grids, i.e. grids with low consumption, having all kinds of impacts on the functionality of the distribution grid. Combined heat and power (CHP) is usually connected closer to the customer but often primarily sized to local heat demand and not to local electricity demand.
- A third aspect is the intermittent nature of electricity supply from RES and CHP. In contrast with electricity supply from conventional large power plants the electricity supply from wind and photovoltaic (PV) installations is far less controllable due to influence on weather conditions. But also the controllability of power supply from CHP and small hydro-power might be poor, because of the dependency on heat demand or water flow respectively.

4.2 Key indicators of six countries in the SEE region

This section of the study provides several key indicators of the six focus countries. *Figure 4.2* depicts electricity production in 6 observed countries in 2014. *Figure 4.3* depicts net maximum capacity of power plants differentiated by type: hydro, thermal, nuclear and RES (including small HPP - hydro power plants connected to a distribution network with installed capacity of 10 MW or less). *Figure 4.4* provides number of electricity customers and number of eligible customers under national legislation (as on the end of 2014).

Overall in 2014 in the region there were 9.874.178 customers, 76.985 GWh electricity produced, 20.664 MW net maximum electrical capacity of power plants, out of which 850 MW of RES (i.e. 4,1 %). For each country *Figure 4.5* depicts share of RES in the net maximum electricity capacity of power plants (PP). Besides it provides country share in the overall installed capacity of RES in the region (as at the end of 2014). It could be observed that neither country exceeds 10 % of RES share in the net maximum electricity capacity of PP. However Croatia dominates in the region with regard of installed capacity of RES (primarily due to the 339 MW installed capacity of wind PP at the end of 2014).

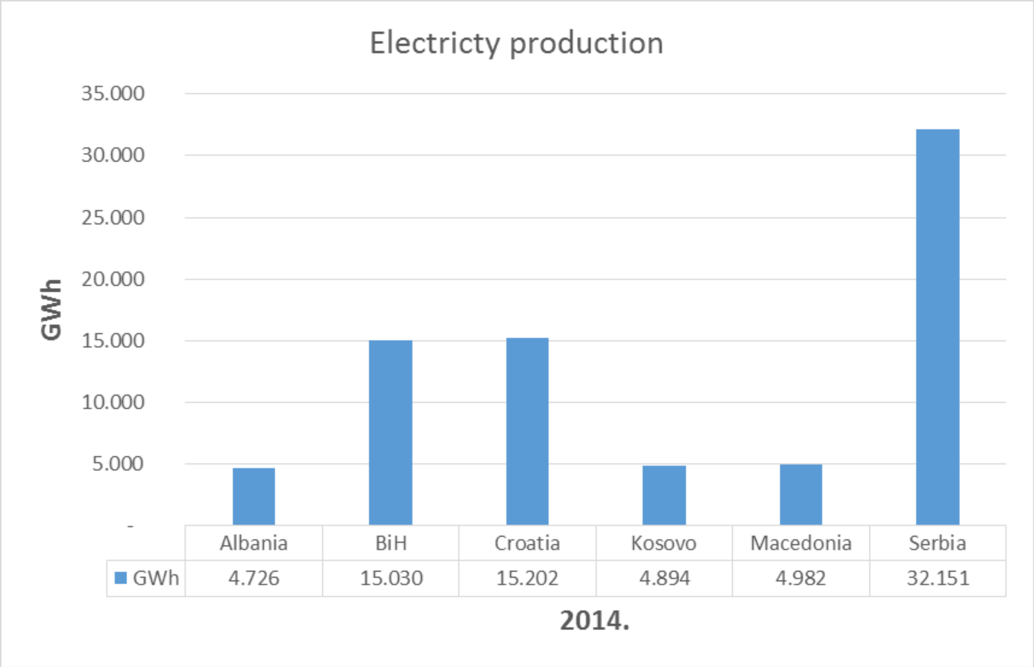


Figure 4.2 Electricity production in six observed SEE countries in 2014
for Croatia this number includes 50% of production in NPP Krsko and production of all PP located on Croatian territory

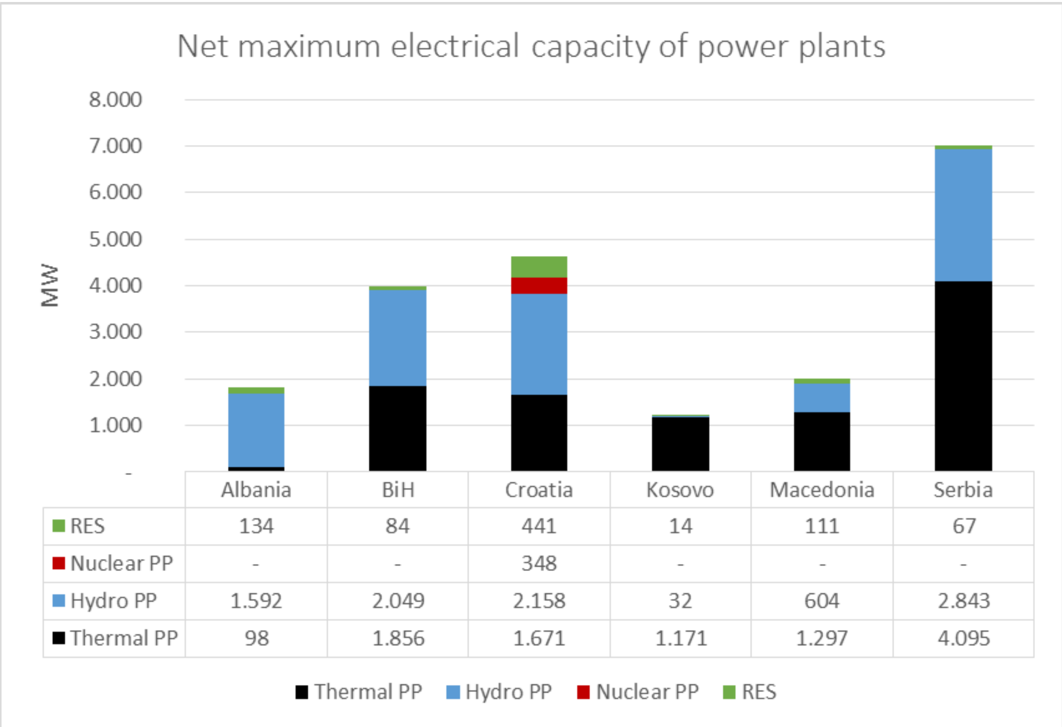


Figure 4.3 Net maximum capacity of power plants in six observed SEE countries in 2014
RES data include small HPP

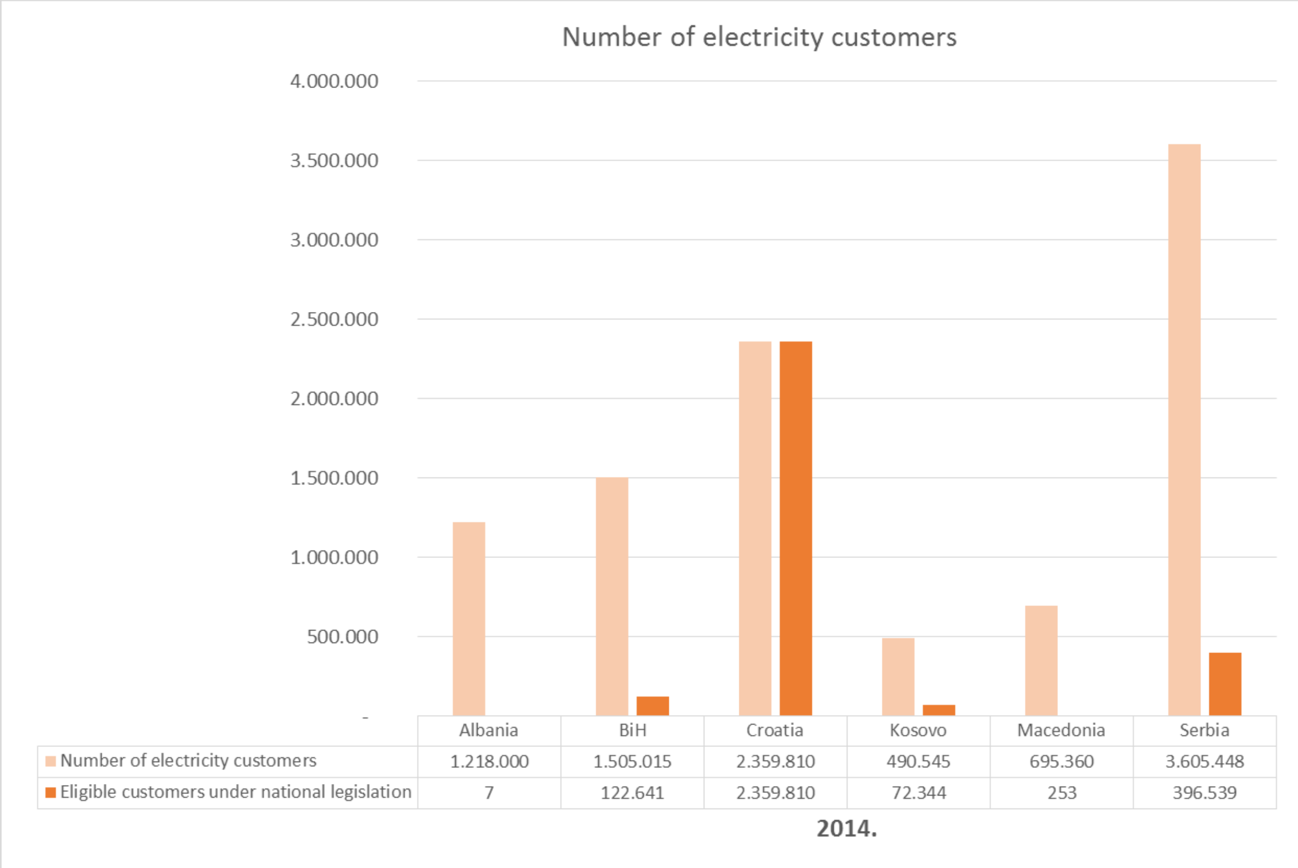


Figure 4.4 Number of electricity customers and eligible customers under national legislation in six observed SEE countries in 2014

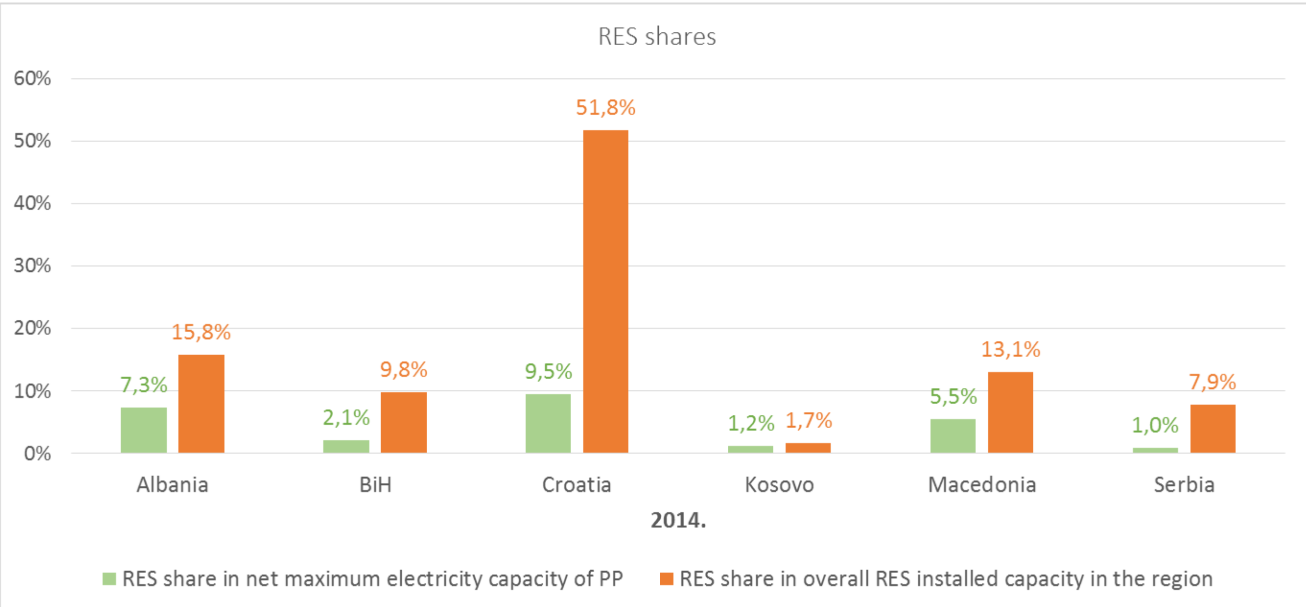


Figure 4.5 RES share in net maximum electricity capacity of PP and in overall RES installed capacity in the region in 2014

Data for five Contracting Parties of the Energy Community in SEE (Albania, Bosnia and Herzegovina, Macedonia, Kosovo and Serbia) were taken from the Energy Community web site [8], while for Croatia from regulatory authority (HERA), market operator (HROTE) and Hrvatska elektroprivreda d.d. (HEP) 2014 annual reports. Comparison of data given in this section and data in the remainder of this study (especial data contained in the section 5.2) is only possible to some extent since the remainder of this study focuses only to distribution system connected power plants. The data given in this section are overall data for the whole power system in the observed countries (i.e. includes also PP connected to transmission system).

The following pictures are related to situation in 2012. *Figure 4.6* depicts the leaders in the region with regard of share of electricity delivered to final customers, Figure 4.7 gives share of distribution network length in SEE DSOs in 2012, while Figure 4.8 gives number of employees in SEE DSOs in 2012. More data on DSOs and distribution networks in the region can be found in South East European Distribution System Operators Benchmarking *Study* [1] (prepared in 2013-2015 period for United States Agency for International Development and United States Energy Association under cooperative agreement USEA/USAID-2013-709-02).

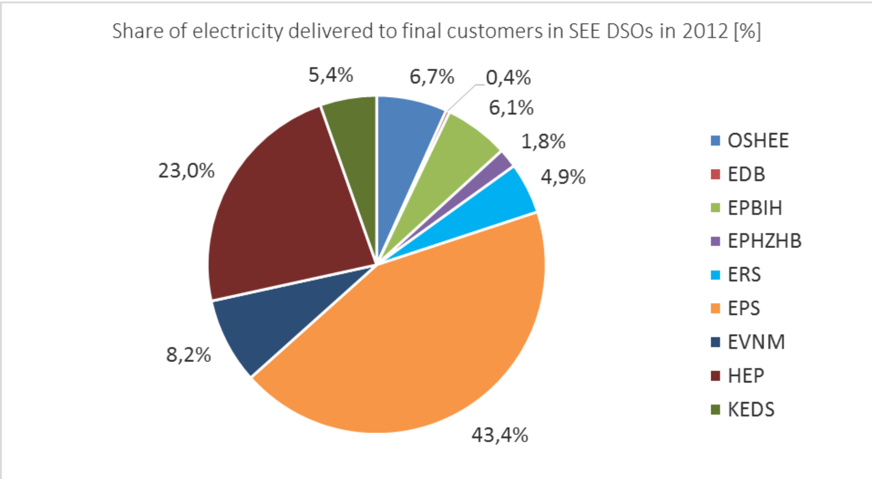


Figure 4.6 Share of electricity delivered to final customers in different SEE DSOs in 2012

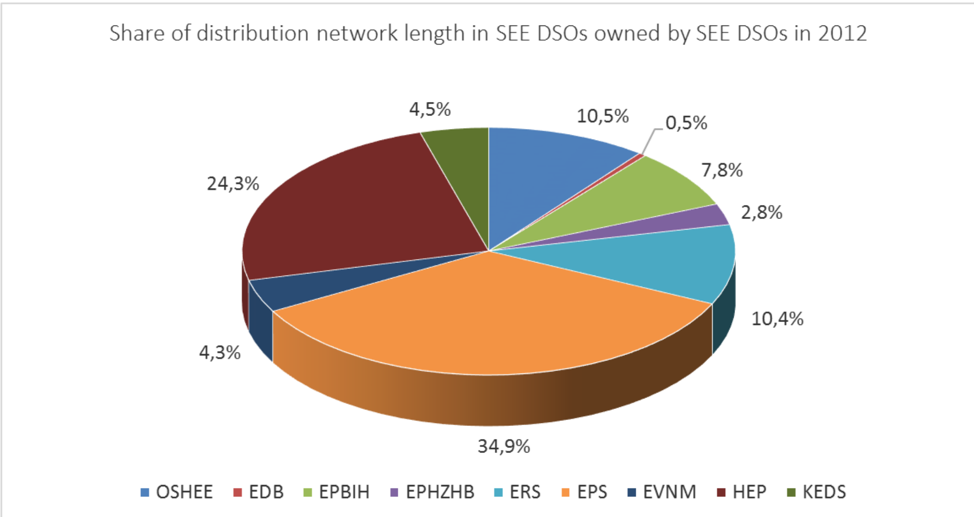


Figure 4.7 Share of distribution network length in SEE DSOs in 2012

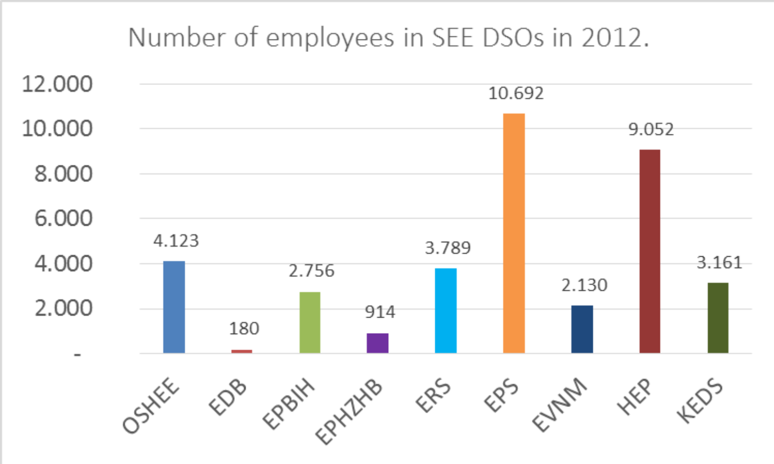


Figure 4.8 Number of employees in SEE DSOs in 2012

Total number of metering points in this region is 9,8 million. There is a large difference between the smallest DSO – EDB (BiH) with just 36.000 metering points to the largest DSO – EPS (Serbia) and its 3,554 million metering points. Serbian EPS is holding 36 % of all metering points in this region. About the same relations will be found in the number of customers and supply area size. Total amount of electricity delivered to final customers in the region is about 64,1 TWh per year. Dominant regional players are Serbian EPS (43,7 %) and Croatian HEP (23,1 %), delivering together more than 2/3 of total electricity delivered in the region. More than half of total electricity in the region (52 %) was delivered to the households, with these shares varying from 44 % in Croatian HEP to 62 % in Macedonian EVNM.

In SEE distribution network there are 119.125 substations, most of it in Serbia (29 %), Croatia (21 %) and Albania (20 %). Distribution network length equals 432.155 km. 0,4 kV aerial network accounts for the largest share in the total distribution network length (58 %), out of which 86 % aerial network. The distribution network is dominantly aerial (82 %), with the highest share in BiH (ERS) and Kosovo (KEDS) (more than 90 %), while in Macedonia (EVNM) and Croatia (HEP) there are largest shares of cable network (more than 30 % of total distribution network length). On the other side, 54 % of all cables and 71 % of all overhead lines can be found in LV network. The largest distribution network can be found in Serbia (35 % of total regional distribution network length) and Croatia (24 %). Average distribution network age in SEE is 27 years. Looking per each DSO, the oldest distribution network can be found in Albania (OSHEE) with the average age of 37 years and Serbia (33 years). The lowest distribution network age is in Kosovo (18 years).

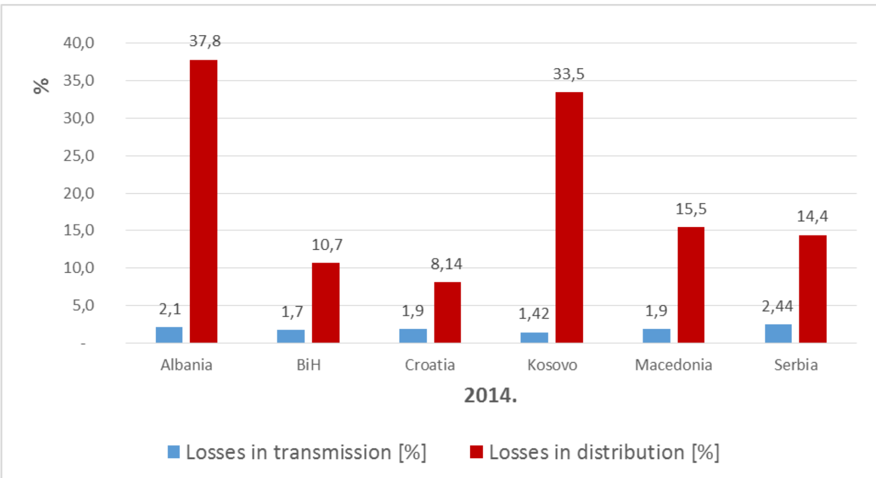


Figure 4.9 Transmission and distribution system losses in 2014

In 9 regional DSOs there are 36.797 employees altogether (*Figure 4.8*). But, just 27.105 employees (74 %) are dealing purely with network business. Remaining 4.943 employees (13 %) are engaged in supply business, while 4.749 (13 %) employees are shared between network and supply business.

4.3 DSOs overview with regard of DGs

The situation of DG penetration in power systems of 6 SEE countries at the end of 2014 is shown in what follows.

4.3.1 Bosnia and Herzegovina (EDB, EPBiH, EPHZHB, ERS)

In EDB (BiH) there are no DGs in parallel operation with distribution system, either DGs under construction or in some early phase of development. The main reasons are lack of support scheme and in general primary and secondary legislation that would maintain a stable and predictable system that would attract investors (Renewable Energy Law was drafted and is in the legislative procedure; it is still open to question establishment of the Operator for Renewable Energy Sources and Cogeneration and redemption (purchase) of electricity produced in RES). It is not yet clear when the laws and bylaws will be adopted and come into force.

Although the renewable energy legal framework, has significantly improved in recent years with the adoption of renewable energy laws in both entities (Federation and Republic of Srpska), changes to the law on concessions facilitating the financing of renewable energy projects, and the adoption of a number of bylaws, the limited incentives for renewable energy projects in both entities are a impediment to full renewable energy sector development. As a result, there is inadequate construction of new renewable energy projects, which are focused at the moment mostly on small hydropower.

Bosnia and Herzegovina committed to a 40 % renewables target for 2020, starting from 34 % in 2009. For operational security of the electricity system, the independent transmission system operator capped the capacity of WPP to be connected to the grid. Capacity is currently limited to a level of 350 MW. Currently there are many more applications for the connection of wind farms pending than the existing capacity cap.

No strategy or legislation dealing with renewable energy exists at state level. There is also no institution at state level or defined procedures to deal with development of renewable energy projects and international cooperation. Renewable energy falls within the competence of the entities. Two separate renewable energy laws were adopted by the two Parliaments of Republic of Srpska and the Federation of Bosnia and Herzegovina in May 2013 and August 2013 respectively. In 2014, Renewable Energy Action Plans were adopted by both entities. The Ministry of Foreign Trade and Economic Relations is currently preparing the NREAP which should include the REAPs of both entities and of Brcko District. It was envisaged to be adopted by October 2015.

In BiH, most attention is given to wind and water as renewable energy sources. The share of RES in the production of electricity in BiH is approximately 40 %, however, this percentage can change due to levels of precipitation. This is mostly due to the extensive use of hydro power plants by the incumbent electricity utilities. However, there is growing development in the area of small HPPs, where there are planned investments by both private investors and the incumbent electricity utilities. There are also plans for the construction of a number of WPP, while several privately owned small PV power plants have already been constructed.

Table 4.1 Total installed capacity of DGs in BiH EPBiH (end of 2014, beginning of 2015)

Total installed capacity	MW						
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation	0,343	1,374	37,678			10,152	49,547
Under construction		0,519	13,822				14,341
Issued connection consent	4,000	43,480	35,077	1,800			84,357
Total	**4,343**	**45,373**	**86,577**	**1,800**		**10,152**	**148,245**

Table 4.2 Number of DGs in BiH EPBiH (end of 2014, beginning of 2015)

Number of PP							
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation	1	29	37			2	69
Under construction		7	10				17
Issued connection consent	1	196	34	1			232
Total	**2**	**232**	**81**	**1**		**2**	**318**

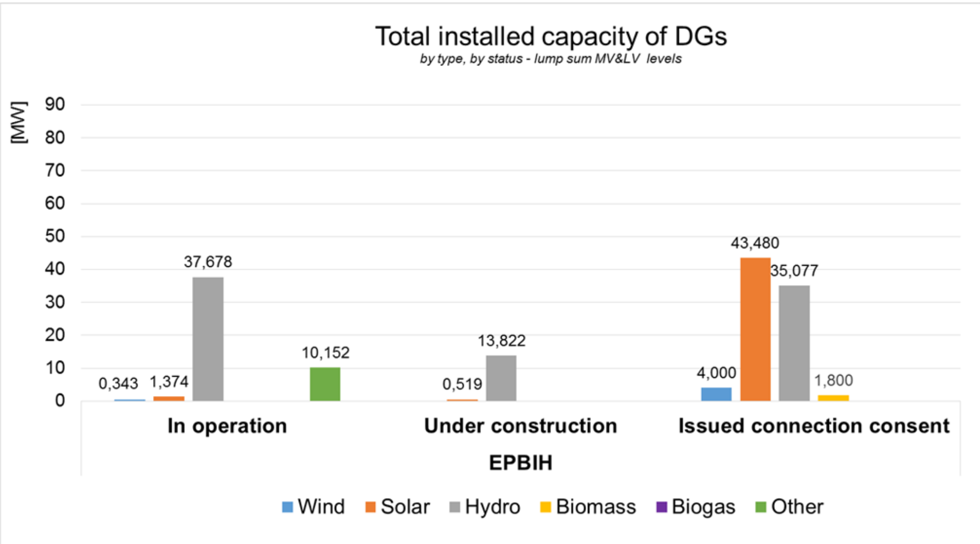


Figure 4.10 Total installed capacity of DGs in BiH EPBiH (end of 2014, beginning of 2015)

Table 4.3 The smallest and largest single DG connected to LV and MV network in BiH EPBiH

Voltage level	LV		MV	
Installed capacity [MW]	**MIN**	**MAX**	**MIN**	**MAX**
In operation	0,004	0,150	0,160	9,400
Under construction	0,010	0,149	0,150	4,478
Issued connection consent	0,006	0,150	0,250	4,990

Table 4.4 Total installed capacity of DGs in BiH EPHZHB (end of 2014, beginning of 2015)

Total installed capacity	**MW**						
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation		1,535	3,899				5,434
Under construction		3,621					3,621
Issued connection consent		1,197					1,197
Total		**6,352**	**3,899**				**10,251**

Table 4.5 Number of DGs in BiH EPHZHB (end of 2014, beginning of 2015)

Number of PP							
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation		11	5				16
Under construction		16					16
Issued connection consent		8					8
Total		**35**	**5**				**40**

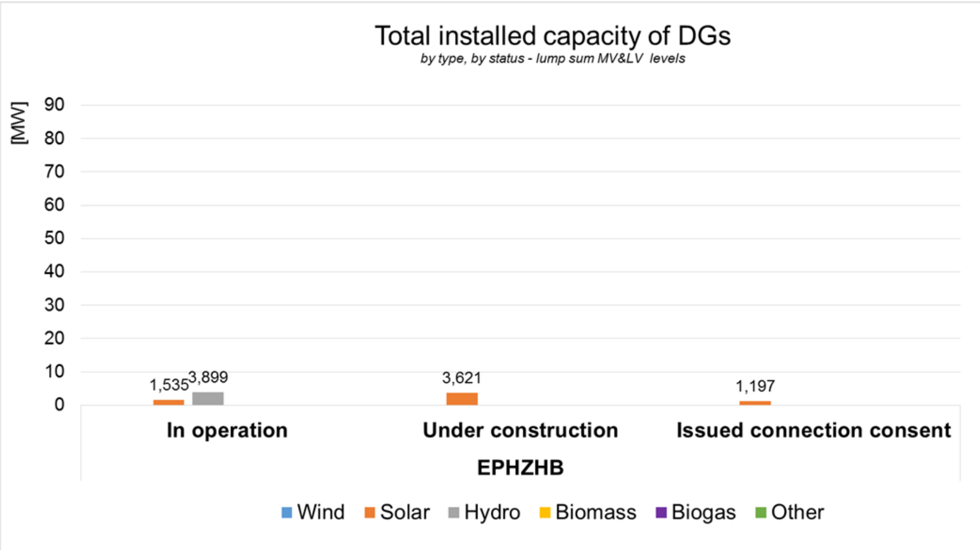


Figure 4.11 Total installed capacity of DGs in BiH EPHZHB (end of 2014, beginning of 2015)

Table 4.6 The smallest and largest single DG connected to LV and MV network in BiH EPHZHB

Voltage level	**LV**		**MV**	
Installed capacity [MW]	**MIN**	**MAX**	**MIN**	**MAX**
In operation	0,008	0,149	0,140	1,270
Under construction	0,020	0,150	0,920	0,998
Issued connection consent			0,149	0,149

Table 4.7 Total installed capacity of DGs in BiH ERS (end of 2014, beginning of 2015)

Total installed capacity	MW						
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation		1,976	51,700				53,676
Under construction		1,859	13,618		0,989		16,466
Issued connection consent		1,859	13,618		0,989		16,466
Total		**5,694**	**78,936**		**1,978**		**86,608**

Table 4.8 Number of DGs in BiH ERS (end of 2014, beginning of 2015)

Number of PP							
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation		25	17				42
Under construction		11	3		1		15
Issued connection consent		11	3		1		15
Total		**47**	**23**		**2**		**72**

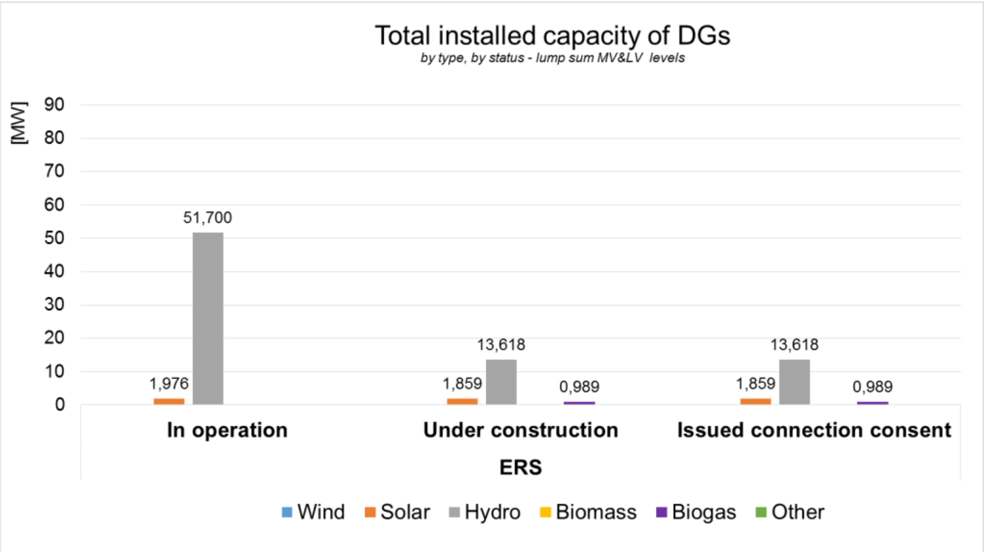


Figure 4.12 Total installed capacity of DGs in BiH ERS (end of 2014, beginning of 2015)

Table 4.9 The smallest and largest single DG connected to LV and MV network in BiH ERS

Voltage level	LV		MV	
Installed capacity [MW]	**MIN**	**MAX**	**MIN**	**MAX**
In operation	0,008	0,250	0,100	8,000
Under construction	0,037	0,180	0,165	4,900
Issued connection consent	0,037	0,180	0,165	4,900

4.3.2 Serbia (EPS)

Besides the 2.822 MW in existing large hydro power plants (HPP) including 614 MW in pump storage, Serbia has currently additional 69,6 MW in 54 small HPPs, 4,5 MW in 5 biogas PPs, 8,6 MW in 96 solar PP, 0,16 MW installed in 1 WPP and 50 MW in 16 CHP and gas PP (*Table 4.10*).

Serbian EPS holds 2nd place in total installed capacity of DGs in operation (i.e. 133 MW). It has about the same number of DGs in operation at MV and LV network. HPPs dominate in total installed capacity of DGs in operation, followed by „other" (CHP & gas PP), *Figure 4.13*. Besides, HPPs lead in total installed capacity DGs in the early phase of implementation.

Table 4.10 Total installed capacity of DGs in Serbian EPS (end of 2014, beginning of 2015)

Total installed capacity	MW						
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation	0,16	8,593	69,559		4,525	49,905	132,742
Under construction							
Issued connection consent	29,535	12,6	235,366	19,112	7,5	24,054	328,167
Total	**29,695**	**21,193**	**304,925**	**19,112**	**12,025**	**73,959**	**460,909**

Table 4.11 Number of DGs in Serbian EPS (end of 2014, beginning of 2015)

Number of PP							
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation	1	96	54		5	16	172
Under construction							
Issued connection consent	4	74	262	14	2	5	361
Total	**5**	**170**	**316**	**14**	**7**	**21**	**533**

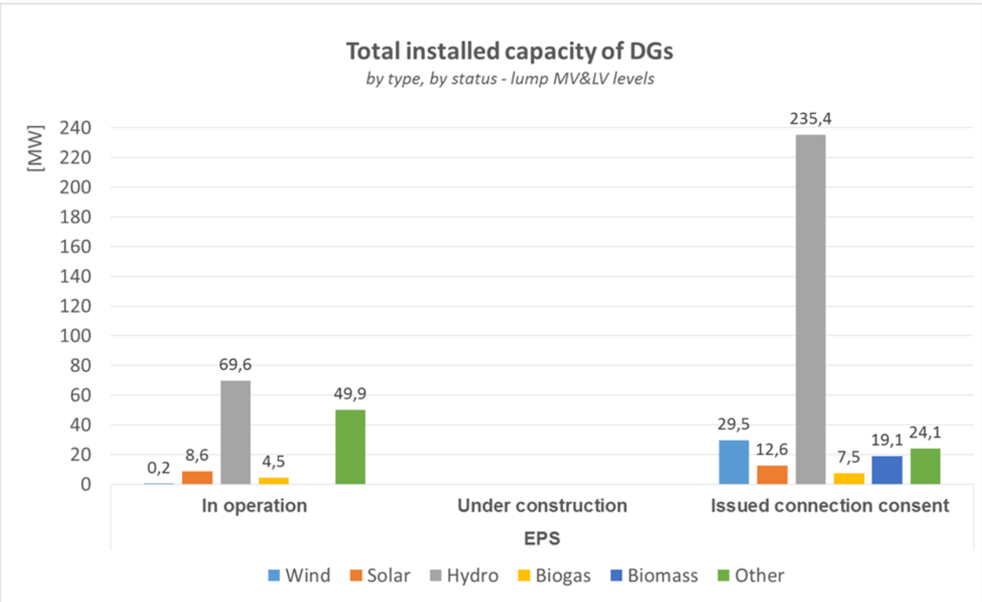


Figure 4.13 Total installed capacity of DGs in Serbian EPS (end of 2014, beginning of 2015)

Under Directive 2009/28/EC, Serbia committed to a binding 27 % target of energy from renewable sources in gross final energy consumption in 2020 compared with 21,2 % in 2009. The Government adopted a National Renewable Energy Action Plan (NREAP) describing the policies and measures to achieve a 27,3 % share in 2020 in June 2013. It envisages increases of renewable energy shares in electricity to 36,6 % from 28,7 % in 2009. The renewable energy needed to meet the 27 % target should, inter alia, come from an additional 1.092 MW of renewable energy capacities in electricity.

Table 4.12 The smallest and largest single DG connected to LV and MV network in Serbian EPS

Voltage level	LV		MV	
Installed capacity [MW]	**MIN**	**MAX**	**MIN**	**MAX**
In operation	0,002	0,420	0,010	12,800
Under construction				
Issued connection consent	0,001	0,780	0,056	9,900

From *Table 4.12* it could be observed that the largest single DG connected to LV and MV network are 0,42 MW and 12,8 MW respectively. Besides, it could be observed that DG units up to 0,78 MW are planned for interconnection to LV network.

According to [2], Serbia is not on track to meet its 2020 targets. Currently, investment in renewable energy remains minimal. The legal framework for renewable energy is split among several laws and by-laws. The Energy Law adopted at the end of 2014 sets the main framework for renewable energy, partly transposing Directive 2009/28/EC. Serbia is a good example of a country that adopted renewable energy legislation but investments in renewable energy projects have still to materialize.

It is worth to mention that in November 2015 the first WPP with installed capacity of 9,9 MW was commissioned in Serbia.

4.3.3 Macedonia (EVNM)

Besides the 603 MW in 8 existing large hydro power plants, Macedonia has currently additional 84,5 MW in 95 small HPPs, 3 MW in 2 biogas power plants and 16 MW in 85 solar PP. Macedonian EVNM holds the 2nd place in the observed region in the number of DGs in operation (i.e. 182; *Table 4.14*). In this DSO the number of DGs at MV surpasses number of DGs at LV (i.e. only 69) which suggests that there is a lack of investments on LV level. It could be observed that there is a lack of investors for non-hydro technologies. HPPs dominate in total installed capacity of DGs in operation (i.e. 84,5 MW; *Table 4.13*), but also in total installed capacity of DGs under construction and in the early phase of development.

Under Directive 2009/28/EC, Macedonia committed to a binding 28 % target of energy from renewable sources in gross final energy consumption in 2020 compared with 21,9 % in 2009. The National Renewable Action Plan (NREAP) describing the policies and measures aiming to achieve the 28 % renewables target in 2020 has not been adopted. This places the country in breach of Directive 2009/28/EC and also creates uncertainties for potential investors.

Table 4.13 Total installed capacity of DGs in Macedonian EVNM (end of 2014, beginning of 2015)

Total installed capacity	MW						
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation		15,831	84,577		2,999		103,407

Under construction		2,060	39,320		4,999		46,379
Issued connection consent		2,900	8,525				11,425
Total		**20,791**	**132,422**		**7,998**		**161,211**

Table 4.14 Number of DGs in Macedonian EVNM (end of 2014, beginning of 2015)

Number of PP							
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation		85	95		2		182
Under construction		4	15		2		21
Issued connection consent		5	17				22
Total		**94**	**127**		**4**		**225**

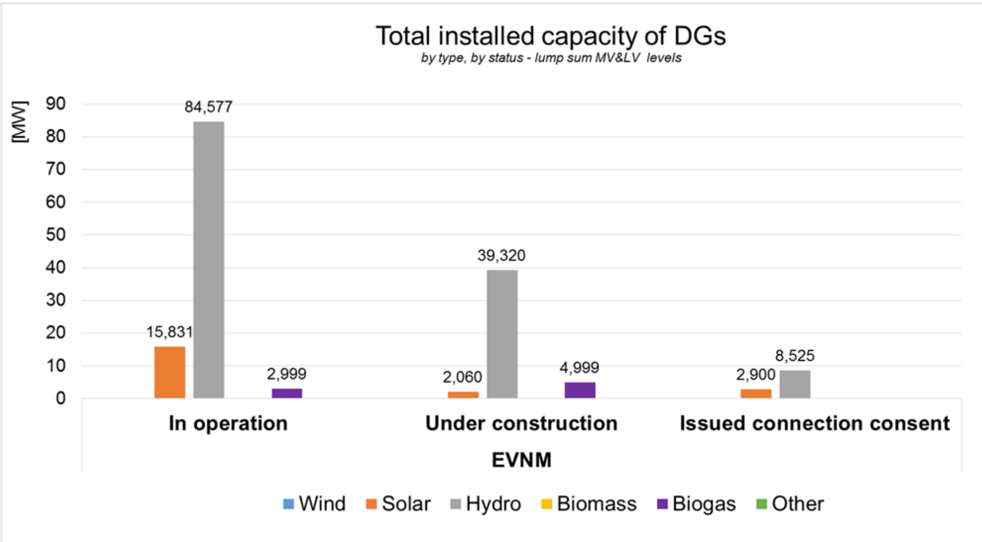


Figure 4.14 Total installed capacity of DGs in Macedonian EVNM (end of 2014, beginning of 2015)

Table 4.15 The smallest and largest single DG connected to LV and MV network in Macedonian EVNM

Voltage level	**LV**		**MV**	
Installed capacity [MW]	**MIN**	**MAX**	**MIN**	**MAX**
In operation	0,011	0,300	0,100	13,300
Under construction			0,999	2,000
Issued connection consent	0,081	0,490	0,120	1,700

From *Table 4.15* it could be observed that the largest single DG connected to LV and MV network are 0,3 MW and 13,3 MW respectively. Besides, it could be observed that DG units up to 0,49 MW are planned for interconnection to LV network.

4.3.4 Croatia (HEP)

Croatian HEP ODS holds the 1st place in number of DGs in operation (i.e. 1.238; *Table 4.17*) and the 3rd place in total installed capacity of DGs in operation (i.e. 115 MW; *Table 4.16*). In this DSO the number of DGs at LV surpasses number of DGs at MV which is ordinary situation in most of the countries with higher share of RES. Contrarily to other DSOs in the region, in Croatia there is a diversity of energy sources with a small share of HPP. WPPs and SPPs dominate in total installed capacity of DGs in operation, *Figure 4.15*. Biomass leads in total installed capacity of DGs under construction and also in the early phase of development, followed by SPP.

Under Directive 2009/28/EC, Croatia committed to a binding 20 % target of energy from renewable sources in gross final energy consumption in 2020 compared with 12,6 % in 2009. The National Renewable Action Plan (NREAP) describing the policies and measures aiming to achieve the 20 % renewables target in 2020 has been adopted in 2013.

Table 4.16 Total installed capacity of DGs in Croatian HEP (end of 2014, beginning of 2015)

Total installed capacity	**MW**						
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation	43,750	36,082	1,712	8,145	13,934	11,459	115,082
Under construction		15,047	4,005	27,810	5,997		52,859
Issued connection consent	34,000	67,079	19,111	79,259	55,821	39,000	294,270
Total	**77,750**	**118,208**	**24,828**	**115,214**	**75,752**	**50,459**	**462,211**

Table 4.17 Number of DGs in Croatian HEP (end of 2014, beginning of 2015)

Number of PP							
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation	6	1.202	6	4	13	7	1.238
Under construction		126	3	10	5		144
Issued connection consent	4	44	13	36	36	12	145
Total	**10**	**1.372**	**22**	**50**	**54**	**19**	**1.527**

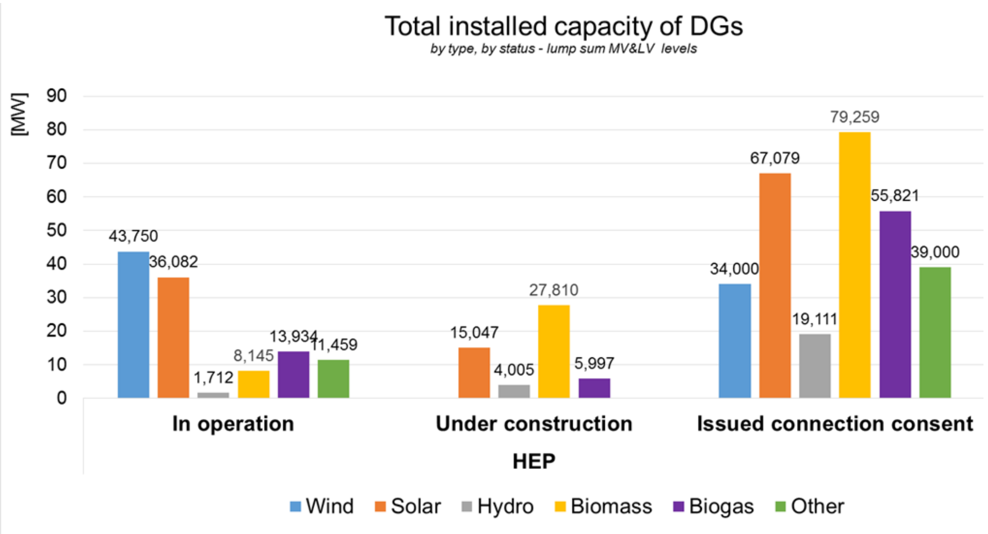


Figure 4.15 Total installed capacity of DGs in Croatian HEP (end of 2014, beginning of 2015)

Table 4.18 The smallest and largest single DG connected to LV and MV network in Croatian HEP

Voltage level	**LV**	**MV**

Installed capacity [MW]	MIN	MAX	MIN	MAX
In operation	0,003	0,499	0,258	10,000
Under construction	0,004	0,300	0,700	8,600
Issued connection consent				

From *Table 4.18* it could be observed that the largest single DG connected to LV and MV network are 0,5 MW and 10 MW respectively, which is in line with limits stipulated by Grid Code.

4.3.5 Kosovo (KEDS)

Kosovo is the richest area in coal reserves in SEE. Hydropower is dominant renewable energy resource currently used (10,6 MW); only 1,35 MW is installed in wind and 0,1 MW in SPP. Theoretically, the territory has high solar and biomass (wood) resources as well as high levels of livestock and agricultural waste.

In 2013 Kosovo adopted the National Renewable Energy Action Plan (NREAP). Kosovo committed to a binding 25 % target of energy from renewable sources in gross final energy consumption in 2020 compared with 18,9 % in 2009.

There are significant losses in the distribution network (around 33,5 % in 2014) partly due to technical inefficiencies, but mostly because of theft, inaccurate metering and commercial losses.

Table 4.19 Total installed capacity of DGs in Kosovo KEDS (end of 2014, beginning of 2015)

Total installed capacity	**MW**						
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation	1,350	0,102	10,580				12,032
Under construction							
Issued connection consent	88,600	9,500	77,470				175,570
Total	**89,950**	**9,602**	**88,050**				**187,602**

Table 4.20 Number of DGs in Kosovo KEDS (end of 2014, beginning of 2015)

Number of PP							
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation	1	1	4				6
Under construction							
Issued connection consent	2	4	12				18
Total	**3**	**5**	**16**				**24**

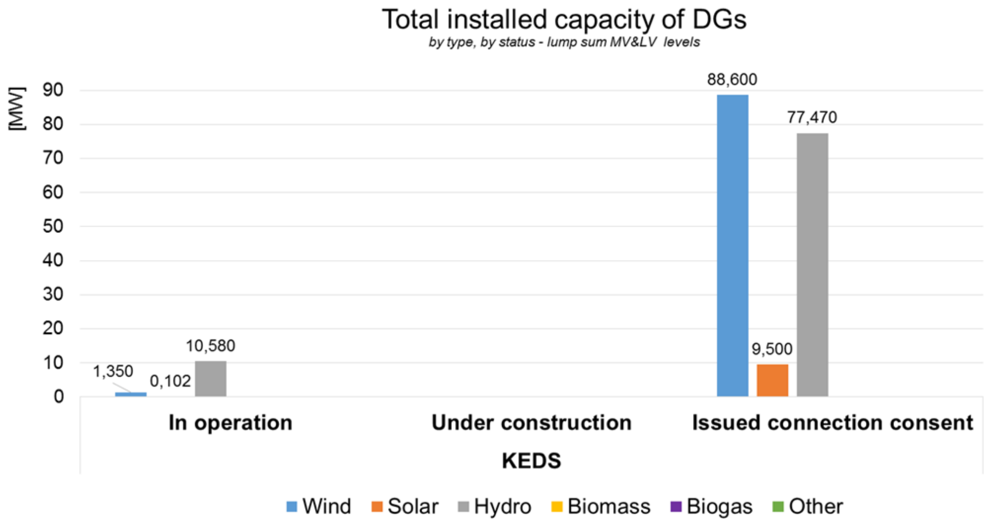


Figure 4.16 Total installed capacity of DGs in Kosovo KEDS (end of 2014, beginning of 2015)

Table 4.21 The smallest and largest single DG connected to LV and MV network in Kosovo KEDS

Voltage level	LV		MV	
Installed capacity [MW]	**MIN**	**MAX**	**MIN**	**MAX**
In operation			0,102	8,000
Under construction				
Issued connection consent			0,500	56,100

4.3.6 Albania (OSHEE)

The current difficult financial situation of the electricity sector caused by high energy losses, accumulated bad debts and reduced collection rates create high risks also for new investments made in renewable energy projects. However, measures for financial consolidation of OShEE (*Operatori i Shperndarjes se Energjise Elektrike*) and control of the revenue, imposed by the Government since 2014, provided significant results in 2014. Losses were reduced by 7 % and the collection rate increased by almost 10 % compared to 2013. The figures further improved in 2015.

The transmission and distribution networks are old and, despite some rehabilitation, technical and non-technical losses account for around 43,5 % (in 2012) of electricity supplied in distribution. Insufficient metering, unpaid bills and illegal connections have dramatically increased electricity consumption and peak demand, thereby weakening the system and leading to underinvestment in much-needed new generation and network capacities. Supply bottlenecks and demand imbalances have constrained electricity supply and reduced the stability and reliability of the grid. Load shedding, black-outs and electricity rationing are common across the country.

Curtailments of electricity from RES have been evidenced in cases when the DSO, due to technical reasons, had to load shed one remote area were the small HPP is located and interconnected. Albanian Government is developing an off-take contract for small HPPs based on "take-or-pay" principle, which will guarantee the small power producers that in case of their curtailment by the network operator without a technical reason they will be compensated for the reduced output.

Albania's main energy resource is hydro (most electricity generated in Albania has been produced by hydropower (97 %)). It is estimated that only 35 % of Albania's hydropower potential is currently being exploited. In terms of other RES, the technical potential for solar, wind and biomass is high.

Table 4.22 Total installed capacity of DGs in Albanian OSHEE (end of 2014, beginning of 2015)

Total installed capacity	**MW**						
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation		1,000	183,000				184,000
Under construction							
Issued connection consent							
Total		**1,000**	**183,000**				**184,000**

Table 4.23 Number of DGs in Albanian OSHEE (end of 2014, beginning of 2015)

Number of PP							
Status	**Wind**	**Solar**	**Hydro**	**Biomass**	**Biogas**	**Other**	**Total**
In operation		1	88				89
Under construction							
Issued connection consent							
Total		**1**	**88**				**89**

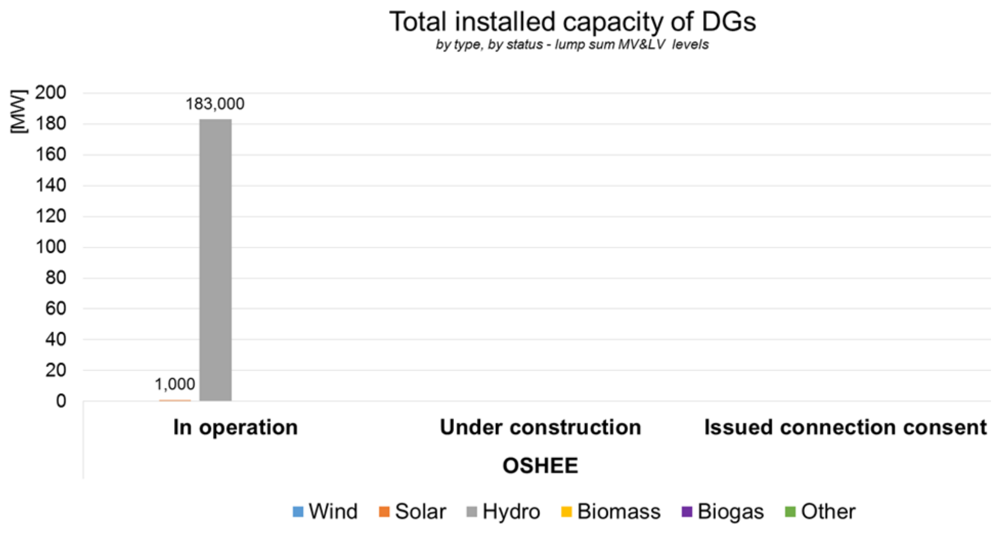


Figure 4.17 Total installed capacity of DGs in Albanian OSHEE (end of 2014, beginning of 2015)

Table 4.24 The smallest and largest single DG connected to LV and MV network in Albanian OSHEE

Voltage level	**LV**		**MV**	
Installed capacity [MW]	**MIN**	**MAX**	**MIN**	**MAX**
In operation			0,072	14,000
Under construction				
Issued connection consent				

With the adoption of the Renewable Energy Law (May, 2013), Albania increased compliance with the renewable energy acquis. However, Parliament decided to postpone the implementation of crucial elements of the Renewable Energy Law to 1 January 2015, including the provisions related to the adoption of the National Renewable Action Plan and the adoption of support schemes. The reason given for this postponement was the harmonization with the new Power Sector Law currently being drafted. Putting its application on hold, however, is a step back even though alignment with the general legal framework for electricity makes sense in view of the many overlaps. Secondary legislation is still missing. The network operators have to increase transparency regarding connection and access to the grids.

4.4 Technical and economic barriers for DG integration in SEE and EU

There may be a multitude of technical considerations associated with connection of increased levels of DGs. The main technical barriers recognised by DSOs in the region are given in *Table 4.25*. It could be observed that in all DSOs effect of DG on voltage regulation is recognised as a major technical issue limiting DG hosting capacity in distribution networks. It is followed by thermal ratings of network components and fault (short circuit) level.

Table 4.25 Technical issues limiting DG hosting capacity of the network in the observed region

Technical issues limiting DG hosting capacity of the networks									
Issues	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE
Thermal ratings	x			x occasionaly			x	x	x
Voltage regulation	x	x	x	x	x	x	x	x	x
Short circuit level	x	x	x	x occasionaly		x			x
Losses		x not limiting	x					x	
Power quality (e.g. flickers, harmonics, fast voltage variations, effects on main signaling, ...)	x harmonics	x	x			x			
Protection	x						x	x	
Other									

Thermal ratings: Each element of the distribution network (lines, transformers etc.), is characterized by a maximum current-carrying capacity (thermal rating). Connection of DG has the effect of changing current flows in the network, which may lead to violation of the loading levels of network elements, especially under maximum generation and minimum load conditions.

Voltage regulation: Voltage regulation is primarily achieved through on-load tap changers (OLTC) controlled by automatic voltage control (AVC) schemes at the HV/MV substations. For transformers MV/MV and MV/LV a change of transmission ratio is not possible during operation (fixed taps). Although DGs may have a positive effect, compensating voltage drops, high DG penetrations complicate voltage control and may lead to overvoltage situations. Another concern is the excessive tapping of OLTC, which increases wear of the equipment and increases maintenance costs.

Fault level: Distribution networks are characterized by a design short circuit capacity, which corresponds to the maximum fault current that can be interrupted by the switchgear used and does not exceed the thermal and mechanical withstand capability of the equipment and standardized network constructions. Since DG contribute to the fault current, their interconnection may lead to exceeding the short circuit capacity of the network.

Power quality: DG installations may induce power quality disturbances, which mainly include fast voltage variations due to switching operations, emission of harmonics and flicker. Disturbances depend very much on the type and technology of DG equipment, as well as on the characteristics of the network and may impose limits to the hosting capacity of specific networks.

Other technical constraints: Reversal of power flows in the network may have a negative effect on certain types of tap changers and on the operation of voltage control schemes. Islanding is a serious consideration in distribution network, which often leads to conservative approaches for the acceptable capacity of DG. Additional technical requirements are also imposed concerning the effect on mains signaling systems, protection, etc.

Table 4.26 provides a detailed overview of the different kinds of barriers with regard to DG deployment that are prevalent in the individual EU Member States (MS) [24]. Concerning network constraints, some MS are struggling with connection delays whereas in other MS the main issue may be the limitation in the network's capacity or maintenance problems.

Table 4.26 Barriers for DG

Barriers for DGs	
Connection charges (major barrier in most countries)	Relatively high
	Discrimination
	Lack of transparency
Network constraints	Limitation in network's capacity
	Connection delays
	Maintenance
	Balancing mechanism
Procedural barriers to network access	Delays, the longevity and complexity of authorisation procedures
Lack of incentive for proactive DSO	Lack of opportunity for pay-back of grid investments
	No incentives in regulatory system (DGs bring additional complexity (costs) in the system)
	DSOs maintain a passive operation philosophy, rather that treating DG as active control element in the operation and planning of DN
Access to market	Problems resulting from previous vertical integration (dominant position of incumbents)
	No direct or difficult access to wholesale market
	Trading mechanism for DG not fully developed / use of "mediator" for market
	Eligibility for market access
	High trading fees
Lack of benefit for DG (not a major barrier thanks to national support mechanisms)	Uncertainty (support mechanism)
	Lack of reward/revenues for connecting DG (positive impact on network losses and grid expansions)

Main barriers across the EU in the connection phase

Grid connection is the first stage that stakeholders encounter for DG integration; it is thus the most "tangible" stage and the one to which stakeholders mostly relate in all countries. There is a strong complementarity between the phases of grid connection and grid development. Several barriers identified in grid connection are also relevant for grid development, for example as regards cost sharing for grid reinforcement or long waiting times linked to building new lines.

The following table provides an overview of the identified issues and possible solutions to mitigate them [23].

Table 4.27 Overview of identified grid connection issues and solutions

Identified issues	Possible solutions
Long lead times & complex procedures	Identification of existing inefficiencies Introduction of qualitative deadlines (e.g. "promptly", "without delay") Reduction of workload for public administration and/or grid operators Harmonisation and simplification of grid connection requirements
Lack of grid capacity / different pace of grid and DG development	Better coordination between grid & DG development Collection of data on DG development from national registries and collection of data on development targets Consideration of DG data in grid development plans
Virtual saturation & Speculation (see section 7.8 in this study)	Definition of milestones in grid connection procedure Introduction of grid reservation fees
Lack of communication weak position DG operator	Initialisation of exchange programs and communication platforms Encouraging stakeholders to participate in exchange programs and communication platforms, as well as to appoint contact persons
Non-shallow costs	Process to define adequate distribution of costs to ensure investment security

Main barriers across the EU in the grid operation

The operation phase seems to provide a fairly favorable environment to the integration of DGs. The research in [23] has revealed that primarily grid curtailment, in the sense of reducing RES production due to grid issues, is a critical issue in a number of countries, especially due to the lack of curtailment rules, compensation issues, and the expected increase of curtailment in the future.

Table 4.28 Overview of identified grid operation issues and solutions

Identified issues	Possible solutions
Curtailment	Introducing a general (or basic) legal framework on: ▪ Curtailment procedure ▪ Responsible bodies ▪ Priorities for RES technologies ▪ Rights and duties of affected stakeholders ▪ Compensation system

As provided in this study, the same applies to SEE. It could be observed that countries in the region have a low share of DG operating on their grid, thus grid operation (with the exception of curtailment) may simply not yet be problematic due to this low DG share. It is possible that with an increasing DG share, the situation will dramatically change in the future and thus early steps would be required to minimize future impacts.

Main barriers across the EU in the grid development phase

As regards the integration of DGs in the context of grid development, it appears that overall, this is a rather unfavorable environment. The main barriers blocking DG integration in this phase are a low consideration for DG in national grid development plans, lengthy procedures for new grid infrastructures, lack of incentives for the grid operator to reinforce the grid. These situations are mostly evident in areas with low population and high DG (RES) potential, often at DSO level. Furthermore, current regulatory instruments may only partially cover costs. Considering the complementarity of DG plants and grids as two parts of a bigger system, it is clear that focus should be given to both of them in parallel. Benefits from this parallel addressing would aid their development and allow mutual benefits (see section 7.11.1).

Table 4.29 Overview of identified grid development issues and solutions

Identified issues	Possible solutions
DGs not sufficiently considered in grid development	Conclusion of unbundling process Involvement of stakeholders
No obligation to reinforce the grid	Introduction of clear legal obligation in national law
Lack of incentives or regulatory instruments	Introduction of measures to create more comparability and transparency Introduction of regulatory measures that incentivise efficient investment

5 TASK 1A: DISTRIBUTED GENERATION CONNECTION PROCEDURE REVIEW AND RECOGNITION OF INADEQUACIES IN THE CURRENT PROCEDURE

5.1 Questionnaire responses

The basic set of input data for this report were collected through the questionnaire distributed to all 9 DSOs in the region on April 30, 2015, including: HEP ODS (Croatia), EPBiH (BiH), EPHZHB (BiH), ERS (BiH), EDB (BiH), EPS (Serbia), EVN (Macedonia), OSHEE (Albania) and KEDS (Kosovo).

Table 5.1 Availability of input data (answers to the questionnaire questions) for each DSO

Q/DSO	Albania	BiH (EPHZHB)	BiH (EPBIH)	BiH (EDB)	BiH (ERS)	Croatia	Serbia	Macedonia	Kosovo
1a	√	√	√	**√**	√	√	√	√	√
1b	**√**	√	√	**√**	√	√	**√**	√	**√**
1c	**√**	√	√	**√**	√	√	√	√	√
2a	x	√	√	√	√	√	√	√	√
2b	√	√	√	√	√	√	√	√	√
2c	x	√	~~√~~	√	√	√	√	~~√~~	√
3	√	√	√	√	√	√	√	√	√
4	√	√	√	√	√	√	√	x	√
5a	√	√	√	√	~~√~~	√	√	√	√
5b	√	√	√	√	√	~~√~~	√	~~√~~	√
6	√	√	√	√	√	√	√	√	√
7	√	√	√	√	√	√	√	√	√
8	√	√	√	√	√	√	√	√	√
9	√	√	~~√~~	√	√	√	√	√	x
10	√	√	√	√	√	√	√	√	√
11	√	√	√	√	√	√	√	√	√
12	√	√	√	√	√	√	√	√	√
13	√	√	√	√	√	√	√	√	√
14	√	√	√	~~√~~	√	√	√	√	√
15	√	~~√~~	√	~~√~~	√	√	√	√	√
16	√	√	√	√	√	√	√	√	√
17	~~√~~	√	√	√	√	√	√	√	√
18	x	√	√	√	√	x	√	√	**√**
19	√	~~√~~	√	√	√	x	~~√~~	√	x
20	√	√	√	√	√	√	~~√~~	√	√
21	√	~~√~~	~~√~~	√	√	√	√	√	~~√~~
22	√	√	√	√	√	√	~~√~~	√	√
23	√	√	~~√~~	√	√	~~√~~	√	√	~~√~~
24	√	√	x	√	√	x	√	√	x
25	√	√	x	√	√	x	√	√	x
26	√	√	√	√	√	√	√	√	x
27	√	√	√	√	√	x	√	√	x
28	x	√	√	**√**	√	x	√	x	√

√ data provided

~~√~~ additional clarification is needed (and requested from DSOs in July, 2015)

√ means that data were not provided because they are not available to DSO or there are no DGs in the observed category

x data not provided or not related to the submitted question

The questionnaire consisted of 28 questions in total, with an aim to capture the current state of play in each DSO related to the interconnection and parallel operation of DGs with distribution system, and also other issues related to subsidizing of DGs electric energy production and electricity market issues like participation in imbalance settlement.

Content of the questionnaire is given in the Appendix I. Responses were collected till May 26, 2015 and all 9 DSOs responded to the questionnaire. The responses are not given in the Appendix since most of the answers were in local language. Accordingly, collected data are analyzed and shown graphically in the following chapters.

Nearly 300 inputs were collected. Finally, 93 % responses were collected (7 % were recognized as not enough informative), while remaining 7 % of the data were not available, as shown in the *Table 5.1*. As some requested data were not available, or not informative enough, additional clarifications were demanded from DSOs in July, 2015 (see Appendix II).

5.2 Distributed generation region overview

This study focuses only to power plants (distributed generation) interconnected to medium (MV) and low (LV) voltage distribution networks; i.e. this means voltages up to and including 35 kV.

In line with EU energy policy targets, as well as national energy strategies, there has been some distributed generation projects in SEE under development in the last decade (see section 4.3). Only in the smallest DSO EDB from BiH there are no power plants, neither in operation nor in some phase of development.

5.2.1 DGs in operation (interconnected to distribution system)

At the end of 2014 there were 656 MW of distributed generation installed capacity. 656 MW relates to 1.814 DGs already integrated to distribution system (i.e. operate in parallel with electric distribution system).

The next four figures provide data on DGs already integrated to distribution system in 9 DSOs.

Figure 5.1 provides data on installed capacity. It could be observed that with regard of installed capacity the leader in the region is Albanian OSHEE (on the 4th place in the region with regard of electricity delivered to final customers and 3rd place in the region with regard of distribution network length and number of employees) with 184 MW (28 %) of installed capacity of DGs.

It is followed by Serbian EPS (on the 1st place in the region with regard of electricity delivered to final customers, distribution network length and number of employees) with 133 MW (20,2 %) of installed capacity of DGs. And on the 3rd place with regard of installed capacity of DGs is Croatian HEP (the 2nd largest DSO in the region with regard of electricity delivered to final customers, distribution network length and number of employees) with 115 MW (17,5 %).

The 4th place holds Macedonian EVNM (on the 3rd place in the region with regard of electricity delivered to final customers and 7th place in the region with regard of distribution network length and number of employees) with 103 MW (15,8 %).

The remaining 5 DSOs have less than 54 MW or 10 % of total installed capacity of DGs interconnected to distribution system.

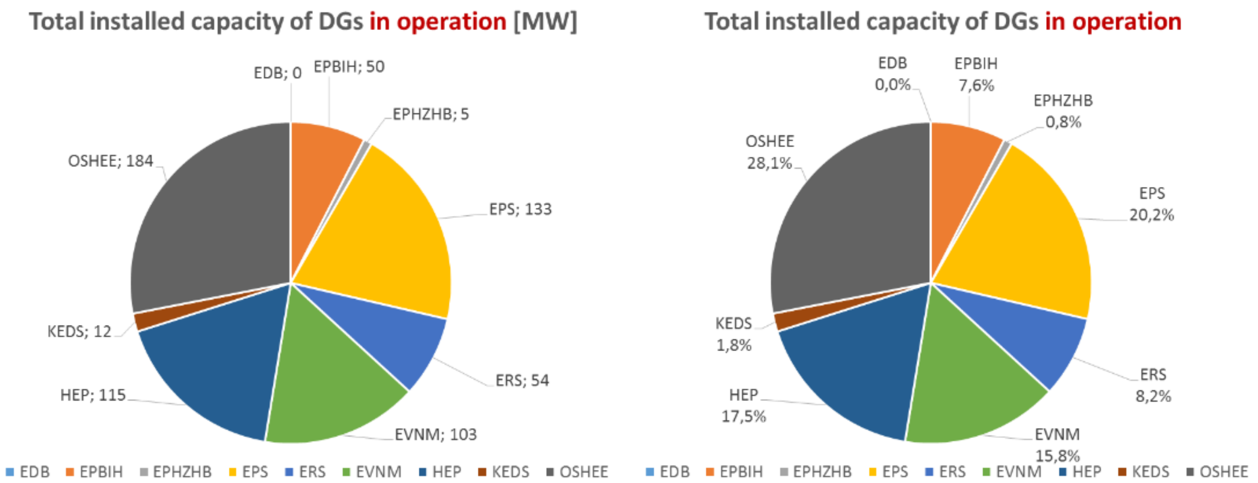


Figure 5.1 Installed capacity of DGs in operation in each SEE DSOs (end of 2014, beginning of 2015)

Figure 5.2 provides data on installed capacity of DGs per energy source: hydro, wind, solar, biogas, biomass and other (i.e. CHP, gas). It could be observed that with regard of installed capacity hydro power plants lead in the region. HPP hold 68 % (i.e. 443 MW) of total installed capacity of all DGs interconnected to distribution systems in the region. They are followed by so called "other energy sources" like CHP and gas PP which hold 11 % (i.e. 72 MW) and solar PP which hold 10 % (i.e. 67 MW) in the region. Wind power plants (WPP) hold only 7 % (i.e. 46 MW), biogas PP 3,3 % (22 MW), and on the last place are biomass PP with 1,2 % (i.e. 8 MW).

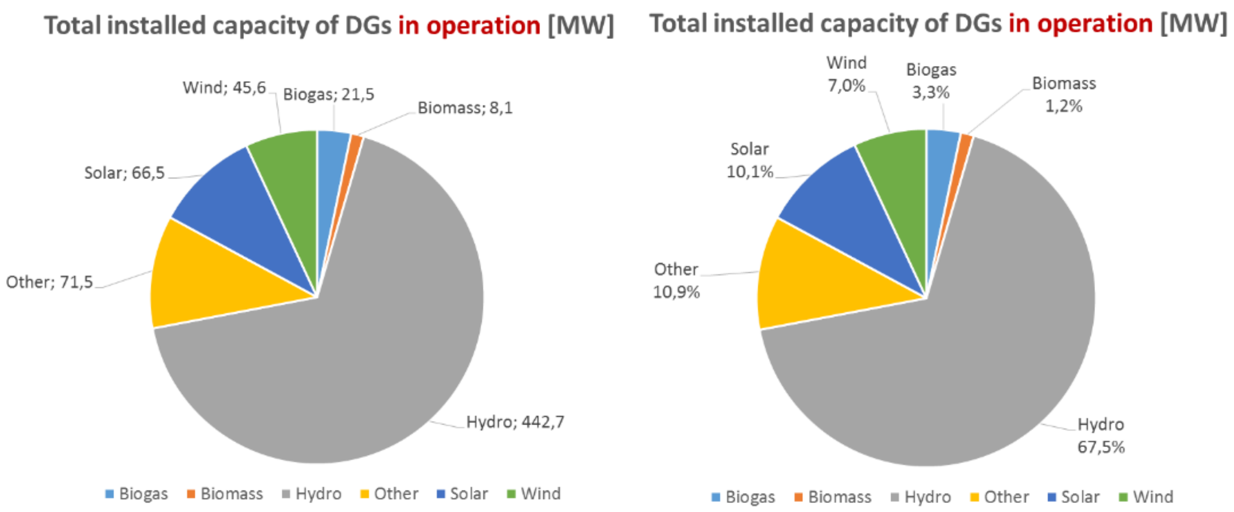


Figure 5.2 Installed capacity of DGs in operation per energy source in SEE (end of 2014, beginning of 2015)

Figure 5.3 provides data on the number of DGs in operation in each SEE DSO. Out of 1.814 DGs already integrated to distribution system, 1.238 (68 %) are interconnected to Croatian HEP (2nd largest DSO in the region). The 2nd place holds Macedonian EVNM with 182 (10 %) DGs already in operation. It is followed by Serbian EPS (172; 9,5 %), Albanian OSHEE (89; 5 %), EPBIH (69; 4 %), ERS (42; 2,3 %), EPHZHB (16; 1 %) and Kosovo KEDS (6; 0,3 %).

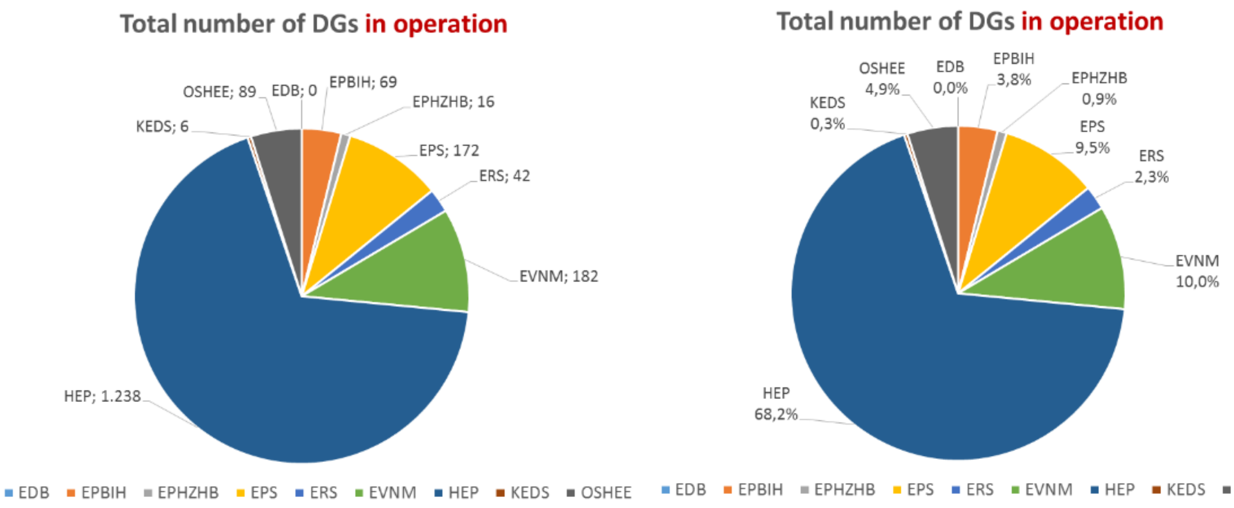


Figure 5.3 Total number of DGs in operation in each SEE DSO (end of 2014, beginning of 2015)

Figure 5.4 provides total number of DGs in operation by energy sources. 1.450 solar PP hold 80 % of total number of DGs in operation. Hydro PPs have the 2nd largest share in total number of DGs (306 HPP); i.e. 17 %. All other energy sources have shares below 1,5 %.

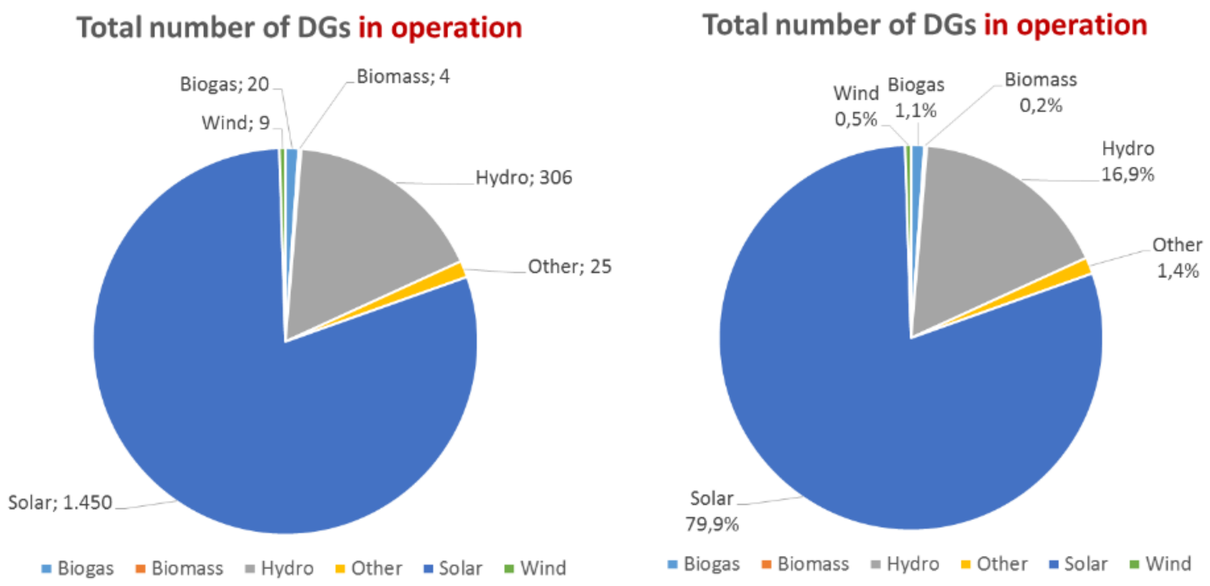


Figure 5.4 Total number of DGs in operation by energy sources in SEE (end of 2014, beginning of 2015)

As given on *Figure 5.5*, the largest number of DGs in operation interconnected to LV distribution network are solar power plants (most of them in Croatia). The largest number of DGs in operation interconnected to MV distribution network are hydro power plants - most of them in Macedonian EVNM (91) and Albanian OSHEE (88), then Serbian EPS (49) and EPBiH (34).

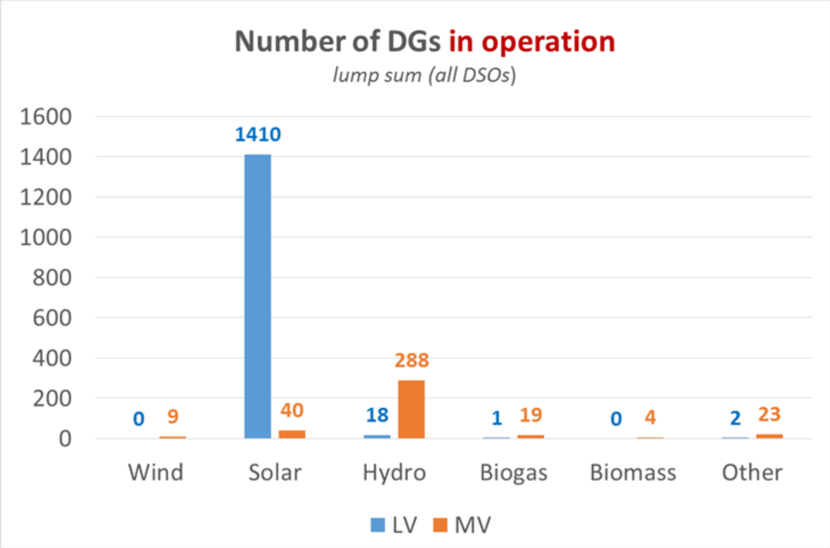


Figure 5.5 Total number of DGs in operation by voltage level in SEE (end of 2014, beginning of 2015)

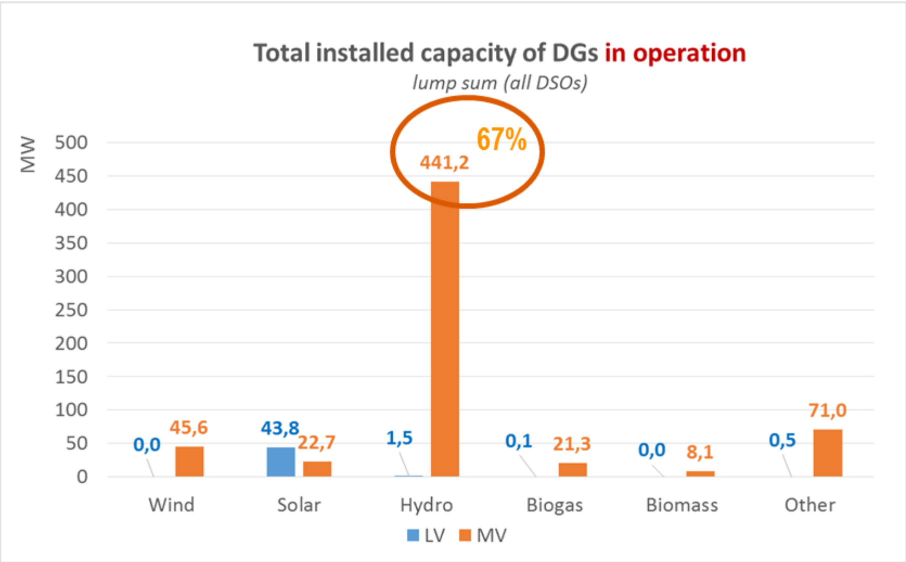


Figure 5.6 Installed capacity of DGs in operation per energy source and voltage level in SEE (end of 2014, beginning of 2015)

Countries across the Balkans have long relied on hydropower. Albania is the world's largest producer of hydropower as a percentage of total production, while Bosnia and Herzegovina generates a substantial share of its electricity from hydropower and has emerged as one of the region's largest power exporters. There has been less investment into wind and solar power, except in Croatia.

It could be concluded that, based on installed capacity of DGs currently in parallel operation with distribution system, the leader:

- in solar power is Croatian HEP (36,1 MW) followed by Macedonian EVNM (15,8 MW) (in the region 66,5 MW; *Figure 5.8*),
- in hydro power is Albanian OSHEE (183 MW) followed by Macedonian EVNM (84,6 MW) (in the region 443 MW; *Figure 5.7*),
- in wind power is Croatian HEP with 43,8 MW (in the region 45,6 MW; *Figure 5.9*).

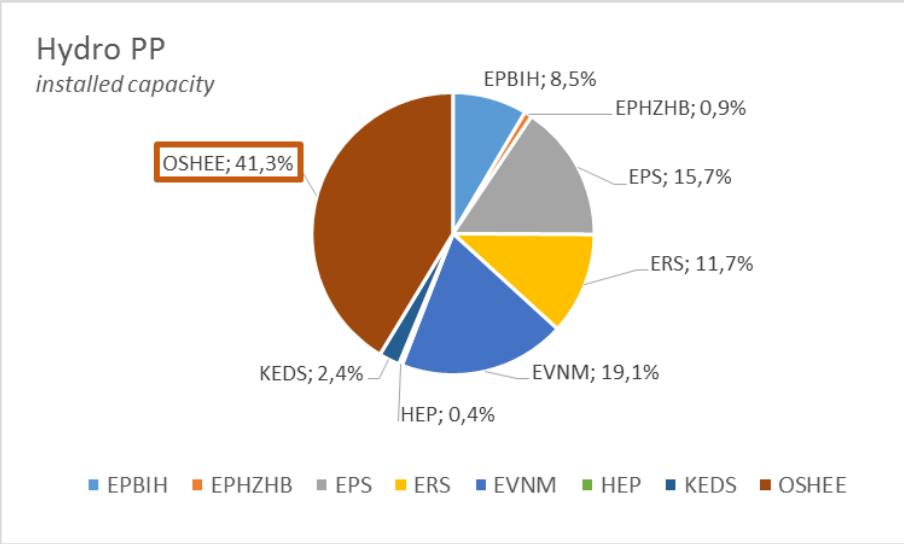


Figure 5.7 Part of total installed capacity of existing HPPs allocated to each SEE DSO (end of 2014, beginning of 2015)

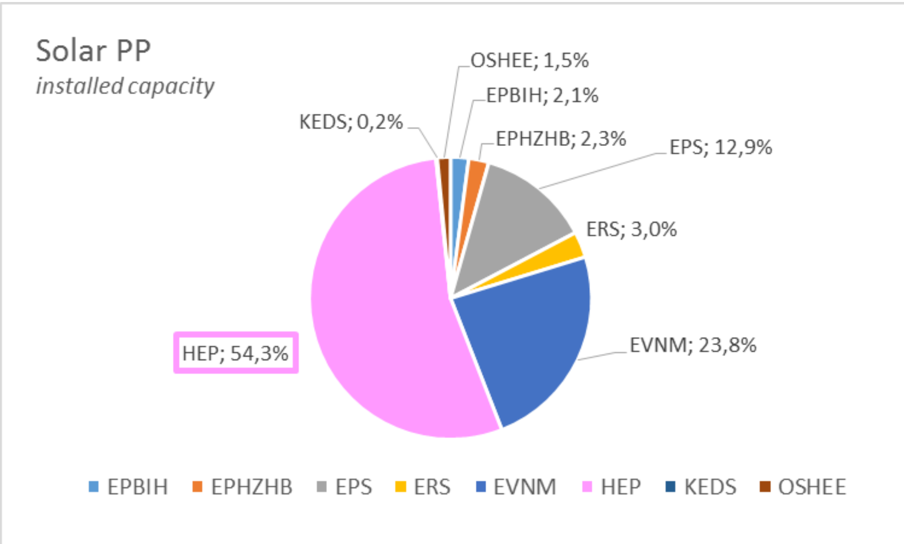


Figure 5.8 Part of total installed capacity of existing SPPs allocated to each SEE DSO (end of 2014, beginning of 2015)

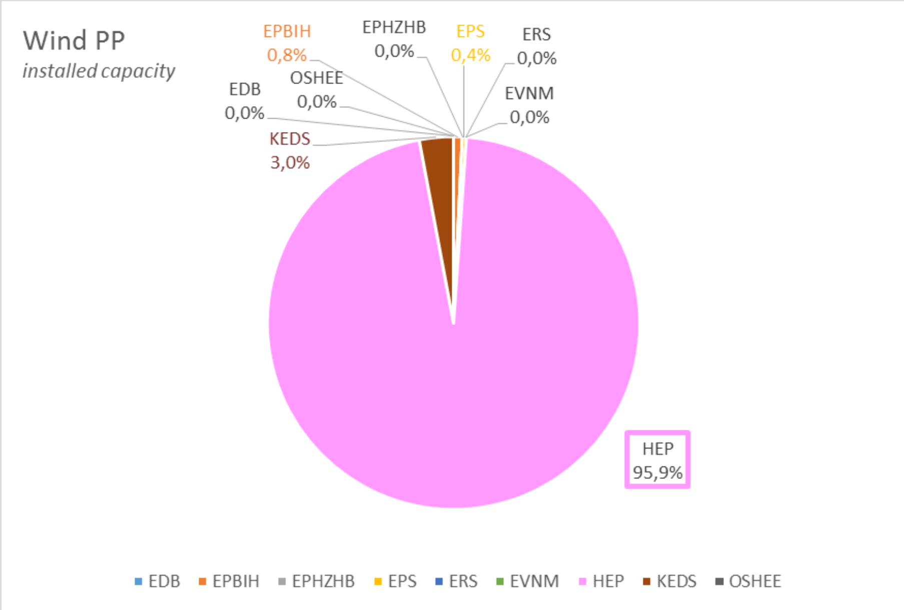


Figure 5.9 Part of total installed capacity of existing WPPs allocated to each SEE DSO (end of 2014, beginning of 2015)

5.2.2 DGs under construction or in some early phase of development (not yet under construction)

As given in *Figure 5.10* and *Table 5.2*, in the region there are additional 213 DGs under construction and 801 in the early phase of development (e.g. investor issued connection consent). Sum total of all existing or planned DGs in the region equals 2.828. The largest portion refers to DGs already in operation, i.e. 64 %, which leads to the conclusion there is no adequate progress in new DGs in the region.

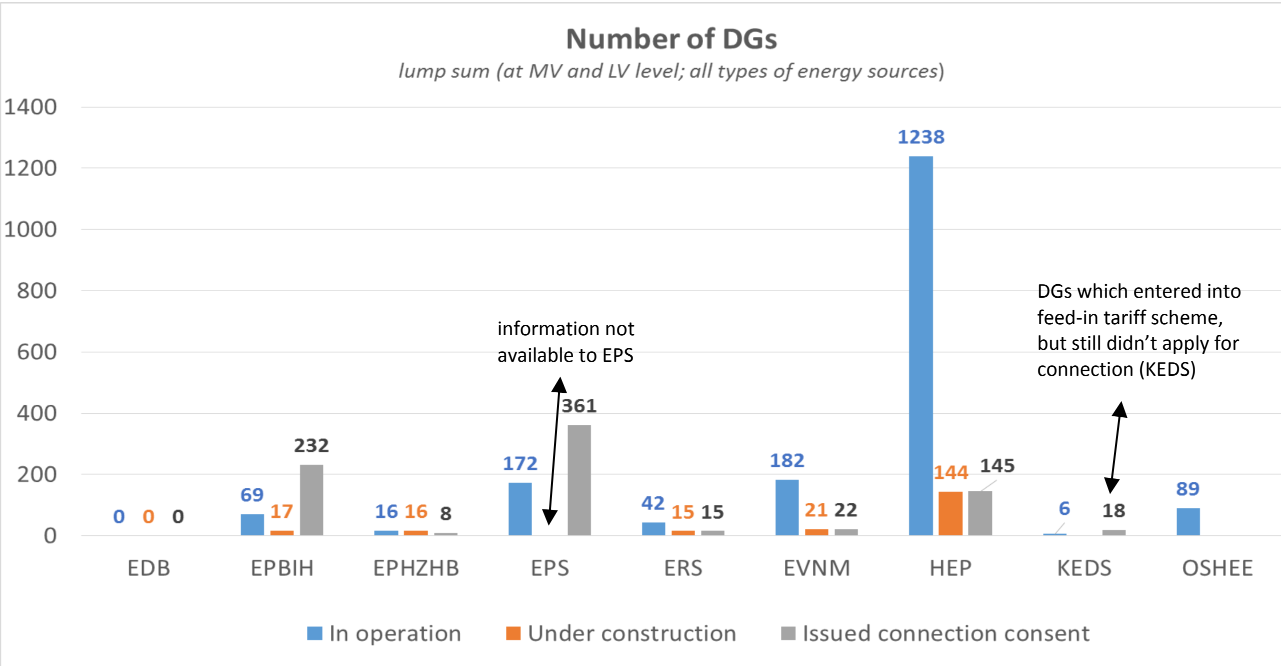


Figure 5.10 Total number of DGs under construction or some early phase of development in SEE DSOs (end of 2014, beginning of 2015)

DSOs data analysis indicates that Croatian HEP leads in the number of DGs in operation and under construction, while Serbian EPS leads in the number of DGs in early phase of development. Here it is important to notice that some DSOs did not provid data for all examined DGs projects statuses; e.g. Albanian OSHEE provided data only for DGs in operation, Serbian EPS does not have information on DGs currently under construction, Kosovo KEDS besides data on DGs in operation provided also data on DGs which entered into feed-in tariff scheme but still did not apply for interconnection to KEDS distribution system.

Table 5.2 Number of DGs under construction or some early phase of development

DSO	In operation	Under construction	Early phase of development (e.g. issued connection consent)
EDB	0	0	0
EPBIH	69	17	232
EPHZHB	16	16	8
EPS	172		361
ERS	42	15	15
EVNM	182	21	22
HEP	1.238	144	145
KEDS	6		18
OSHEE	89		
Total	**1.814**	**213**	**801**
[%]	*64 %*	*7,5 %*	*28,5 %*

Figure 5.11 and *Table 5.3* present the same numbers but differentiated by voltage level of DGs interconnection. 64 % of all DGs (in operation, under construction or some other phase of development) are or will be interconnected to LV network, while the remaining 36 % to MV network. It is important to notice here that Kosovo KEDS and Albanian OSHEE reported only DGs interconnected to MV network.

Larger number of DGs in operation are connected to LV (primarily due to the situation in Croatian HEP), and also lager number of DGs in early phase of development shall be connected to MV (primarily due to the situation in Serbian EPS and Croatian HEP).

Croatian HEP leads in a number of existing DGs connected to LV network (*Figure 5.12*), while Macedonian EVNM leads in a number of existing DGs connected to MV network (*Figure 5.13*).

Except EPBiH, all other DSOs indicated that in most cases newly planned DGs, currently in early phase of development, will be connected to MV level.

Table 5.3 Number of DGs under construction or some early phase of development differentiated by voltage level of interconnection

Status / Voltage level of interconnection	LV	MV	Total
In operation	**1.431**	**383**	**1.814**
EDB	0	0	0
EPBIH	32	37	69
EPHZHB	11	5	16
EPS	88	84	172
ERS	25	17	42
EVNM	69	113	182
HEP	1.206	32	1.238
KEDS		6	6
OSHEE		89	89
Under construction	**146**	**67**	**213**
EDB	0	0	0
EPBIH	6	11	17
EPHZHB	14	2	16
EPS			
ERS	5	10	15
EVNM	6	15	21
HEP	115	29	144
KEDS			
OSHEE			
Early phase of development (e.g. issued connection consent)	**253**	**548**	**801**
EDB	0	0	0
EPBIH	184	48	232
EPHZHB		8	8
EPS	58	303	361
ERS	5	10	15
EVNM	6	16	22
HEP		145	145
KEDS		18	18
OSHEE			
Total	**1.830**	**998**	**2.828**

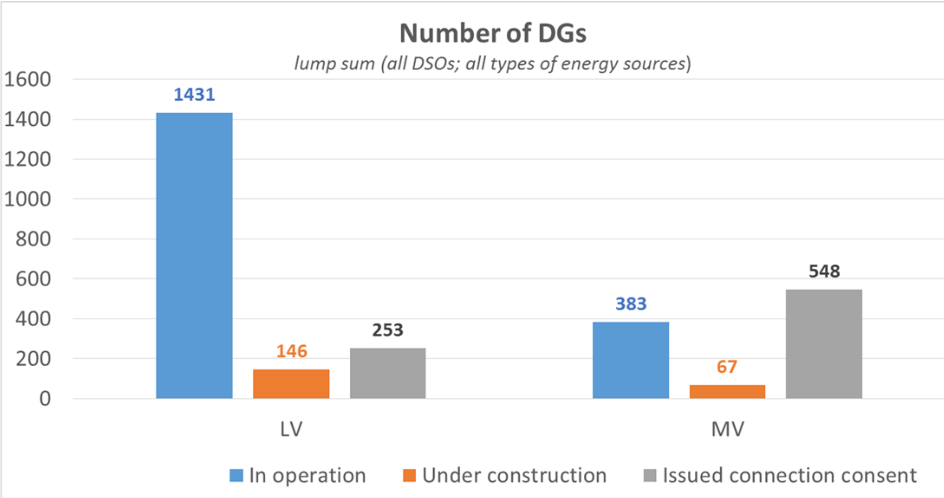


Figure 5.11 Total number of DGs under construction or some early phase of development in SEE DSOs differentiated by voltage level of connection (end of 2014, beginning of 2015)

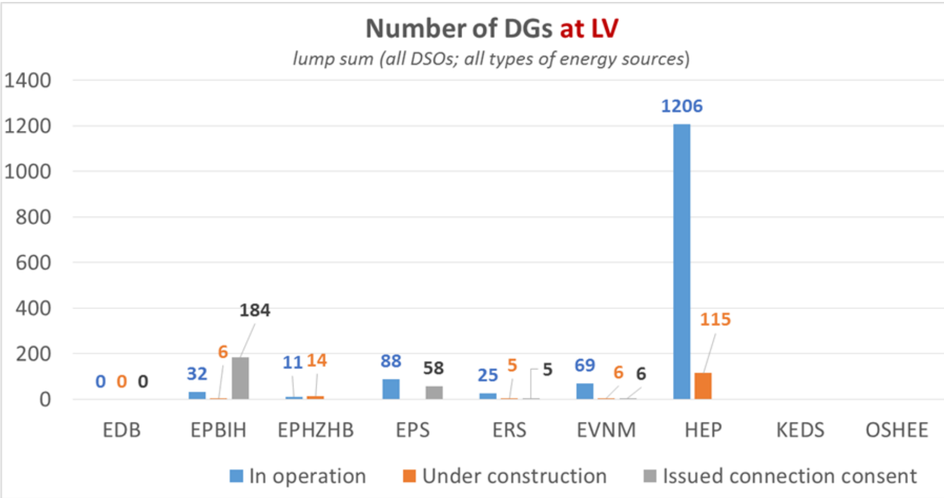


Figure 5.12 Total number of DGs interconnected or planned to be interconnected to LV network in SEE DSOs

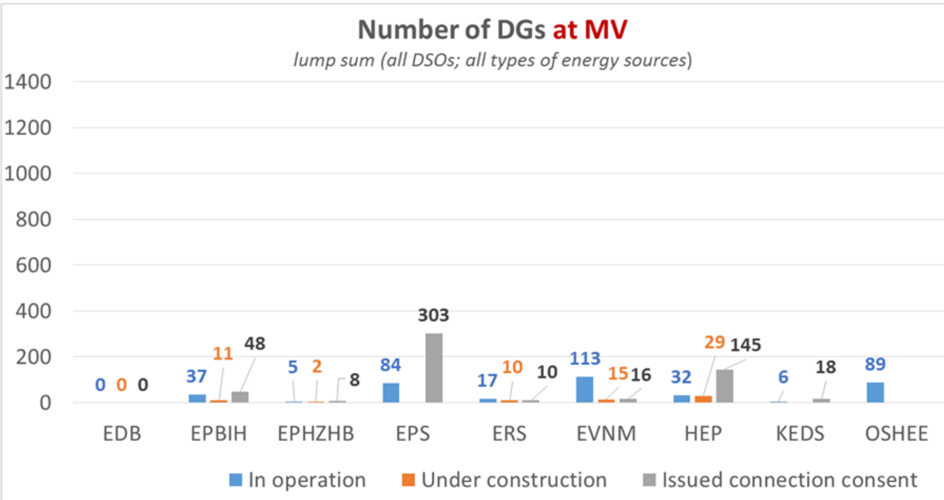
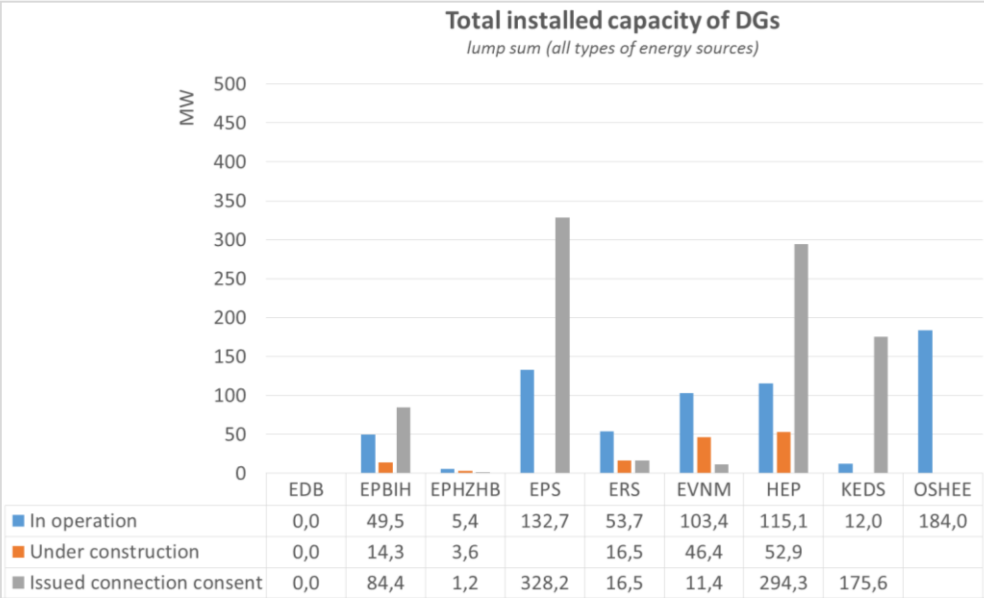


Figure 5.13 Total number of DGs interconnected or planned to be interconnected to MV network in SEE DSOs

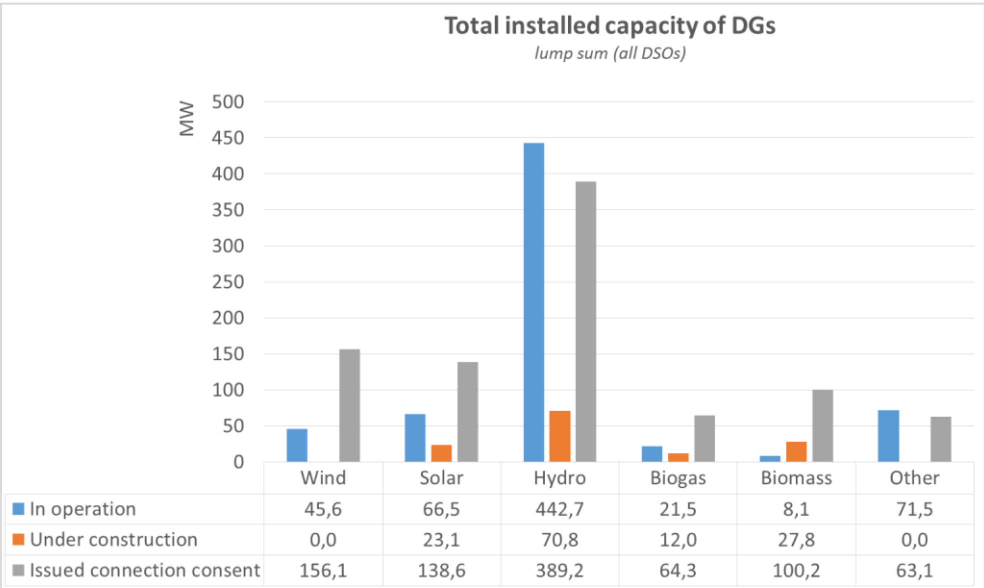
As given in *Figure 5.14*, Croatian HEP and Macedonian EVN lead in total installed capacity of DGs under construction, while Serbian EPS and Croatian HEP in total installed capacity of DGs in early phase of development.



	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE
In operation	0,0	49,5	5,4	132,7	53,7	103,4	115,1	12,0	184,0
Under construction	0,0	14,3	3,6		16,5	46,4	52,9		
Issued connection consent	0,0	84,4	1,2	328,2	16,5	11,4	294,3	175,6	

Figure 5.14 Total installed capacity of existing or planned DGs to be interconnected to distribution network in each SEE DSOs

Besides, holding major share in total installed capacity of all DGs interconnected to distribution systems in the region, hydro power plants lead in total installed capacity of DGs under construction and also in total installed capacity of DGs in early phase of development (*Figure 5.15*).



	Wind	Solar	Hydro	Biogas	Biomass	Other
In operation	45,6	66,5	442,7	21,5	8,1	71,5
Under construction	0,0	23,1	70,8	12,0	27,8	0,0
Issued connection consent	156,1	138,6	389,2	64,3	100,2	63,1

Figure 5.15 Total installed capacity of existing or planned DGs to be interconnected to distribution network differentiated by energy source

5.3 Legal framework relevant for DG interconnection procedure in SEE

Table 5.4 contains overview of currently effective legislative framework relevant for DG connection procedure in each DSO – Law on Energy, Law on Electricity (EL), Renewable Energy Law (REL), national Renewable Energy action plan (NREAP), Distribution Code, Methodology for connection charging and General terms and condition for electricity supply and/or use of network.

Table 5.4 Legal framework dealing with DGs – focus on interconnection procedure

Legal framework	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE
Law on Energy				December 2014	2009	February 2011	February 2013 *amended in September 2015*	2010	
Law on Electricity	2004 *amended in February 2013*	2013			2002		February 2013 *amended in September 2015*	2010	April 2015
Renewable Energy Law	*being drafted*	August 2013		X	May 2013	X	October 2015	X	May 2013
NREAP	X	Entity REAP May 2014		June 2013	Entity REAP May 2014	X	October 2013	November 2013	X
Distribution code	November 2011	2008	2008	2009 *amendments of Distribution Code 2014*	2009 Rulebook for RES March 2014	June 2012 *amended three times during 2014*	March 2006	April 2015	2010
Methodology for connection charging	November 2011	October 2014		August 2012	December 2008	*(contained in Distribution Code)*	March 2006	new is being drafted Distribution Charging Principles 2012	2012
General terms and condition for electricity supply and/or use of network	September 2014	October 2014		2013	August 2008	June 2011	2006 *(sections dealing with connection procedure are still valid)* July 2015	August 2011	

5.4 Rated distributed generation capacity

Table 5.5 Maximum and minimum rated power of DG connected to LV and MV distribution network in each DSO in the observed region

Voltage level	LV		MV	
DSO	**MIN**	**MAX**	**MIN**	**MAX**
EDB				
In operation				
Under construction				
Issued connection consent				
EPBIH				
In operation	0,004	0,150	0,160	9,400
Under construction	0,010	0,149	0,150	4,478
Issued connection consent	0,006	0,150	0,250	4,990
EPHZHB				
In operation	0,008	0,149	0,140	1,270
Under construction	0,020	0,150	0,920	0,998
Issued connection consent			0,149	0,149
EPS				
In operation	0,002	0,420	0,010	12,800
Under construction				
Issued connection consent	0,001	**0,780**	0,056	9,900
ERS				
In operation	0,008	0,250	0,100	8,000
Under construction	0,037	0,180	0,165	4,900
Issued connection consent	0,037	0,180	0,165	4,900
EVNM				
In operation	0,011	0,300	0,100	13,300
Under construction			0,999	2,000
Issued connection consent	0,081	0,490	0,120	1,700
HEP				
In operation	0,003	***0,499***	0,258	10,000
Under construction	0,004	0,300	0,700	8,600
Issued connection consent				
KEDS				
In operation			0,102	8,000
Under construction				
Issued connection consent			0,500	56,100
OSHEE				
In operation			0,072	***14,000***
Under construction				
Issued connection consent				

DSO usually consider rated (nominal) power of DG is crucial element that dictates the voltage level to which DG is to be connected. Some Grid Codes have provisions with upper permitted nominal power for single DG per connection voltage level (e.g. in Croatia 500 kW for LV and 10 MW for MV).

Currently in the region (*Table 5.5*):

- maximum rated power of DGs connected to MV network equals 14 MW (OSHEE),
- maximum rated power of DGs connected to LV network equals 500 kW (HEP).

This study suggests the minimum and maximum rated (nominal) power of DG up to which a interconnection to the MV distribution network is permissible shall depend on the type and operating regime of the generating plant and on the conditions in distribution network. For this reason, it is not possible to provide general information in this respect, or advisable to stipulate such "hard" limits in Grid Codes (as in Croatia). This question can only be solved on a case-by-case basis through a network analysis carried out by the DSO in the interconnection procedure. Connection rules shall stipulate "soft" limits just to inform investors:

- whom to file application for interconnection (i.e. to DSO or TSO) and
- at which voltage level appropriate connection point of DG might be.

Optimal connection point shall be the result of technical studies performed by DSO based on technical criteria and mandatory requirements for interconnection stipulated in Distribution Code or Connection rules.

5.5 Analyses performed in the DG connection process

In order to be able to determine optimal connection point, and also necessary reinforcements/additions in the network, DSOs rely on analyses performed in the interconnection procedure. In countries where there is a beneficial investment climate for RES producers DSOs are overwhelmed by unprecedented amounts of DG connection applications, which need to be evaluated in a fast and reliable manner (concurrently).

DG production often exceeds the local loads of the lines and substations, especially at low load periods, causing reversal of flows and power in-feeds to the upstream networks. This situation can potentially cause several problems, including voltage regulations issues, low power factors at the HV/MV substations, power quality concerns, high short circuit levels etc. Due to those reasons DSOs are reluctant to grant permissions to connect DG, unless detailed studies of individual feeders are performed. Such studies cause significant delays to DG integration and numerous complaints by the DG developers and investors. Hence, the need arises for simplified methodologies and practical rules of thumb that will allow DSOs to assess the hosting capacity of the distribution network in a fast but reliable manner, without the need to resort to detailed analytical studies.

Table 5.6 for each SEE DSO provides analyses performed by DSO. It could be observed that DSOs perform most of analyses listed in the study questionnaire (even some complex inherent to HV networks like dynamic analysis).

Table 5.6 Analyses performed in the DG connection procedure

Studies for connection									
Analysis	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE
Steady-state load flow analysis	Yes	Yes	Yes (over 250 kW)	Yes	Yes	Yes	Yes	Yes	Yes
Reactive power and voltage control analysis	Yes	Yes	Yes (over 250 kW)	Yes	Yes	Yes	Yes	Yes	Yes
Short circuit analysis	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Dynamic analysis	*Yes*							*Yes*	
Impact on network losses	Yes	Yes	Yes (over 250 kW)	Yes	Yes		Yes	Yes	
Power quality analysis	Yes	Yes	Yes (performance measurement during commissioning)	Yes	Yes		Yes	Yes	Yes
Protection setting elaboration	Yes	Yes	Yes (over 250 kW)		Yes		Yes	Yes	
DG contribution to the ancillary services	*Yes*							*Yes*	
Island operation of DG	*Yes*			*Yes*				*Yes*	
Harmonics analysis	Yes	Yes		Yes	Yes		Yes	Yes	

In Republic of Srpska conducting distribution impact studies for DG interconnection is legally stipulated (which is not the case with most of other SEE DSOs). For example, in Republic of Srpska *Rulebook defining the method, terms and conditions and procedure for connection to the distribution network of generation facilities which use renewable energy sources and efficient co-generation* (2014) Article 9.2 prescribes the following analysis:

- analysis of possibility to interconnect for DGs up to including 250 kW (i.e. simple study) and
- grid connection study for DGs over 250 kW (i.e. detailed study).

Analysis of possibility to interconnect and grid connection study serve to determine optimal connection point and technical requirements for the network user (producer) requesting interconnection into the distribution network while taking into consideration of the following:

- technical criteria for connection (as proposed in section 4 of the Rulebook),
- hosting capacity of the existing distribution network,
- development plans of the distribution network,
- short-circuit power at the point of connection,
- production and consumption of network users in the distribution network and
- type and characteristics of distributed generators.

Section IX-11 of the Rulebook explicitly prescribes the following calculations to be performed:

- short circuit power at the point of connection,
- loading capacity of existing network equipment with regard to the connected DG according to the relevant dimensioning rules,
- stationary operation voltage change,
- rapid voltage change (short-term voltage changes) due to switching operations.

Besides, short-circuit criteria is checked for distributed generators over 1 MVA; i.e. with regard of DG short-circuit current contribution.

The check of compliance with emission limits is based on assessment of:

- flickers (WPP and SPP),
- harmonics (DGs with network infeed through inverters/converters),
- DC injection (DGs with network infeed through inverters),

- commutation notches,
- voltage unbalance,
- disturbance to equipment for the signal transmission over the power supply network (e.g. ripple control system).

According to the Article 37 of General terms and conditions for electricity supply (August, 2008), for RES and efficient co-generation producers with installed capacity below 10 MW, DSO performs analysis of possibility to interconnect and grid connection study free of charge. For all other producers there is a fee for studies performed by DSO. This costs are part of the connection charge.

From *Table 5.7* it could be seen that in 6 DSO studies are performed exclusively by DSOs, while in other 3 (EDB, EPBiH and HEP) some (primarily protection setting study) are performed by investor and then authorised by DSO.

Table 5.7 Party performing connection analyses

DSO	Who performs connection analyses
EDB	DSO some analyses might be required from Investor (which is regulated by connection contract)
EPBIH	DSO exception is protection setting study (elaboration) which is carried out by Investor (authorised by DSO)
EPHZHB	DSO
EPS	DSO
ERS	DSO
EVNM	DSO *Investor can perform his own analyses after the receiving of the data for distribution network from DSO*
HEP	DSO some analyses carried out by Investor (authorised by DSO) - protection setting study (elaboration) & study on PP impact on the network
KEDS	DSO *In case of disputes investor can perform his own analyses after the receiving of the data for distribution network from DSO (provision of the necessary information may be charged).*
OSHEE	Not legally prescribed (now DSO)

Table 5.8 shows software normally used in SEE DSOs for connection analyses.

Table 5.9 shows who is financing connection studies in the region. The most frequently this is the investor:

- part of connection charge: EPS,EVNM,KEDS, ERS (non-incentivized DGs), HEP (LV),
- paid separately: EPHZHB, HEP (MV), EPBIH (>128 kW),

but also DSO:

- covered by network fee: EDB, OSHEE, EPBIH (<128 kW) ERS (incentivized DGs).

Table 5.8 Software used for connection analyses in SEE DSOs

DSO	Software
EDB	DMS (http://www.schneider-electric-dms.com/)
EPBIH	DG PowerCAD (http://www.fractal.hr/) WinDIS
EPHZHB	DG PowerCAD (http://www.fractal.hr/) WinDIS
EPS	PSA-power system assistant (http://powersystemassistant.com) DMS (http://www.schneider-electric-dms.com/)
ERS	No
EVNM	DMS software
HEP	Neplan 360
KEDS	Powerfactory (http://www.digsilent.de)
OSHEE	Bison

Table 5.9 Financing of studies performed in the connection procedure in SEE DSOs

DSO	Financing
EDB	In principal **DSO** (as a part of network fee) DSO might ask for other necessary studies, like more detailed system impact study, which are then financed by Investor
EPBIH	**DSO** for DGs of 128 kW and lower (as part of network fee) **Investor** for DGs above 128 kW (paid aside of connection charge)
EPHZHB	**Investor** (paid aside of connection charge)
EPS	**Investor** (it is part of connection charge) *Investor finances issuing of DSO opinion - if Investor later on decides to build the cost of it is deducted from the cost of connection.* *There is a price list for: issuing DSO opinion on the conditions for connection, performing analysis of optimum conditions of connection, so called extension of opinions regarding connection and issuing conditions and the design of connection*
ERS	**Investor** (it is part of connection charge) *(Article 37 of General terms and conditions for electricity supply) *for RES and efficient co-generation producers <10 MW DSO performs analysis of possibility to interconnect and grid connection study free of charge*
EVNM	**Investor** (it is part of connection charge)
HEP	**Investor** either as a part of connection charge, or paid separately
KEDS	**Investor** (it is part of connection charge)
OSHEE	The law doesn't specify - currently is financed by **DSO**

This study recommends SEE DSOs to consider IEEE 1547.7-2013 Guide to Conducting Distribution Impact Studies for Distributed Resource Interconnection. It provides good practices for engineering studies of the potential impacts of a DG or aggregate DGs interconnected to the electric power distribution system. Study scope and extent are described as functions of identifiable characteristics of the DG, the EPS, and the interconnection. The following studies and data requirements are described in detail:

- conventional studies:
    - steady state simulation,
    - system protection studies: short circuit analysis, protective device coordination, automatic restoration coordination, area EPS power system grounding, synchronization, unintentional islanding, arc flash hazard study,
- special system impact studies,
    - quasi-static simulation,
    - dynamic simulation: system stability, stability analysis interpretation, voltage and frequency ride-through,
    - electromagnetic transient simulation: ferroresonance, interaction of different types of DG, temporary overvoltage, system grounding, DC injection,
    - harmonics and flicker: harmonic analysis, harmonics resonance, flicker.

5.6 Connection criteria and requirements

In order to mitigate against possible implications related to the high penetration of DG, DSOs have established evaluation methodologies based on technical criteria including the thermal ratings of network components, short circuit contribution and resulting fault level, voltage regulation, power quality (flicker, harmonics) etc. These criteria ensure the integrity, security of operation and safety of the networks but still constitute limits for the DG hosting capacity of the networks.

All DSOs carry out studies that evaluate whether the connection of DG violates the rating of network elements (transformers and feeder thermal ratings). Ensuring that the short circuit capacity remains below the design fault level is always a fundamental consideration, particularly near the MV busbars of the HV/MV substations.

Another important criterion applied universally is the effect of DG on voltage regulation. Voltage levels in extreme operating conditions, typically at maximum load – no generation and at minimum load – maximum generation, are assessed to ensure than operating constraints are met. The aggregate voltage rise due to all DG connected to the network is also limited by many DSOs. *Table 5.10* provides connection criteria of admissible voltage change due to DG connection in SEE DSO. It could be observed that only 3 out of 9 DSOs have defined such criteria.

Table 5.10 Admissible voltage change criteria requirements due to DG connection in SEE DSOs

Admissible voltage changes	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE
criteria for connection	No	No	Yes *2%*	Yes *±5% (SG)* *±2% MV (other generators)* *±3% LV (other generators)*	Yes *±5%*	No	No		Yes *±5%*

Some DSOs in EU carry out studies so as to evaluate the impact on the losses of the network by the connection of DG. Certain DSOs even require that the interconnection of DG does not lead to an increase of network losses. With regard of losses in SEE, all DSOs carry out studies to evaluate the impact on the losses by the connection of DG (*Table 5.11*). However, SEE DSOs do not require that interconnection of DG does not lead to an increase of losses.

Table 5.11 Impact on losses criteria in SEE DSOs

Losses	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE
Criteria for connection	No	No	No	No	No	No	No	No	No
Criteria for operation	Yes*	No	No	No	No	No	No	No	No

**(EDB) If during initial start-up or after commissioning of the generating plant DSO determines that DG increases losses in the network it may require from DG to take some measures to lower losses; noncompliance to DSO request may result with disconnection of DG from the network.*

Criteria related to power quality disturbances, such as fast voltage variations, flicker and harmonics emissions, are also employed in EU DSOs, either as simplified screening rules or within more elaborate evaluation methodologies.

Serbia (EPS) and Republic of Srpska (ERS) shall serve as a model to other DSOs with regard of prescribing technical criteria for interconnection assessment.

For example, Serbian Distribution Code from 2009 (section 3.5) has governed DGs interconnected to distribution network with capacity up until 10 MW. In March 2014 by amendments of Distribution Code this limit has been replaced by 6 technical criteria that are evaluated in the connection procedure:

a) maximum DG power,
b) stationary operation voltage boundaries and (short-term) voltage changes due to switching operations,
c) short circuit capacity,
d) steady-state thermal constraints,
e) harmonics,
f) flickers.

Certain criteria are checked based on availability of data (submitted by investor) in the individual phases. At the end of construction and before commissioning, power plants must meet all six criteria.

5.7 Provision of ancillary services

With an increased penetration of DG at the distribution level combined with the objective of a more reliable and cost-efficient network development and operation, it becomes supportive to apply new ancillary services in the operation of distribution and transmission network by DSO and TSO.

Indeed, in the future, with higher levels of network automation and DG controllability, DG could help DSO to solve:

- voltage control,
- congestion management,
- optimization of grid losses,
- improvement of voltage quality,

- network restoration / black start,
- islanded operation.

Unfortunately, currently in SEE DSO DGs are not providing ancillary services to any DSO. Furthermore, only in two countries (Macedonia and Croatia) such services are stipulated by law.

Table 5.12 Provision of ancillary services in SEE DSOs

Ancillary services	EDB	EPBIH	EPHZHB	EPS	ERS	EVNM	HEP	KEDS	OSHEE
Deployed	X	X	X	X	X	X	X	X*	X
Stipulated by law	X					yes	yes		

X not developed at the distribution level

* KEDS did not provide answer to this question

Here it is worth to mention that Albanian Government is developing an off-take contract for small HPPs based on "take-or-pay" principle, which will guarantee the small power producers that in case of their curtailment by the network operator without a technical reason they will be compensated for the reduced output.

5.8 Connection steps and charging

Power systems generally have connection and access procedures as regulated mechanisms for users wishing to interact with the network, with the objective of injecting energy into or absorbing energy from the system.

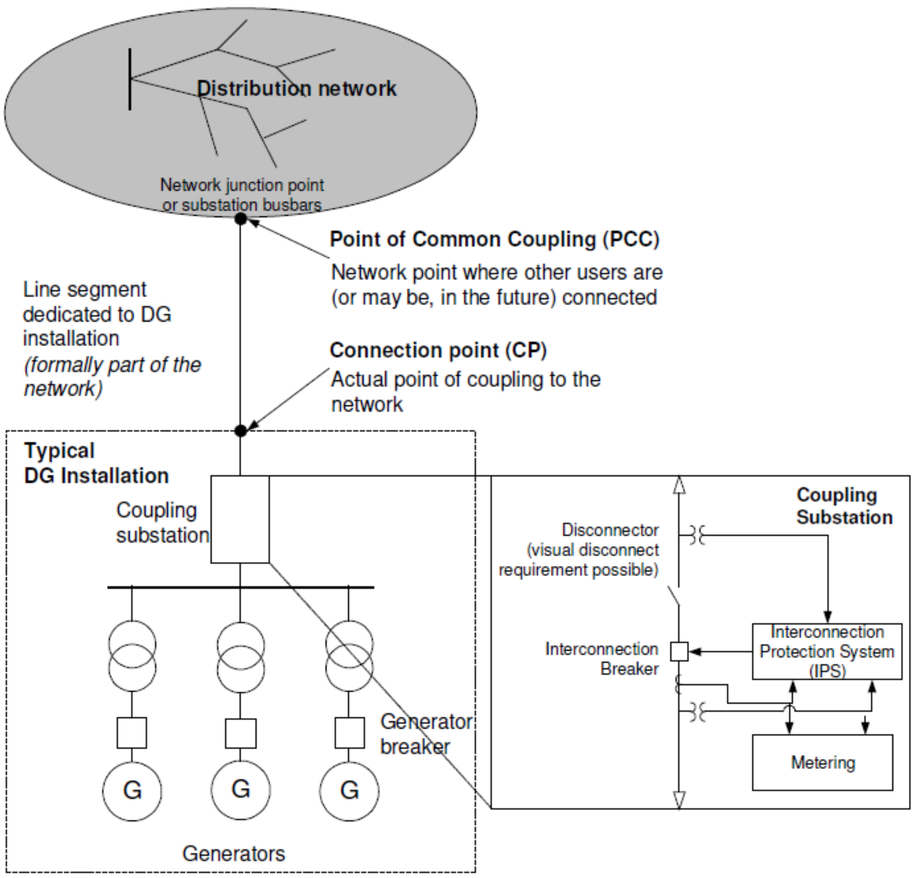


Figure 5.16 Connection Point (CP) and Point of Common Coupling (PCC) [21]

The term *connection* is associated with the physical integration of network user into the power system. Connection refers to the actions by which an existing or intending user seeks to "link" and actually links a facility or set of facilities to the network. The term *access* may be understood differently according to the power system considered. Although sometimes it may be understood as a part of the connection process, perhaps more often access designates the actual *use* of the system facilities.

DG installations are connected to the distribution grid using arrangements as it is schematically illustrated in *Figure 5.16*. Most important is the differentiation between the actual connection point (CP) and the Point of Common Coupling (PCC). The latter is defined as the closest to the DG installation node, where other users are (or may be) connected and it may differ from the physical point of coupling, when the installation is interconnected via a dedicated line segment, as in *Figure 5.16*.

Figure 5.17 depicts IEEE1547.2 [17] definitions of PCC and point of distributed resource (DR) connection. These are commonly used in U.S. state-level interconnection rules:

- ***distributed generation****: electric generation facilities connected to an area EPS through a PCC; a subset of DR,*
- ***distributed resources****: sources of electric power that are not directly connected to a bulk power transmission system. DR includes both generators and energy storage technologies,*
- ***point of common coupling****: the point where a local EPS is connected to an area EPS,*
- ***point of distributed resources connection (point of DR connection)****: the point where a DR unit is electrically connected in an EPS,*
- ***electric power system:*** *facilities that deliver electric power to a load,*
- ***area electric power system (area EPS):*** *an EPS that serves local EPSs. Typically, an area EPS has primary access to public rights-of-way, priority crossing of property boundaries, etc., and is subject to regulatory oversight.*

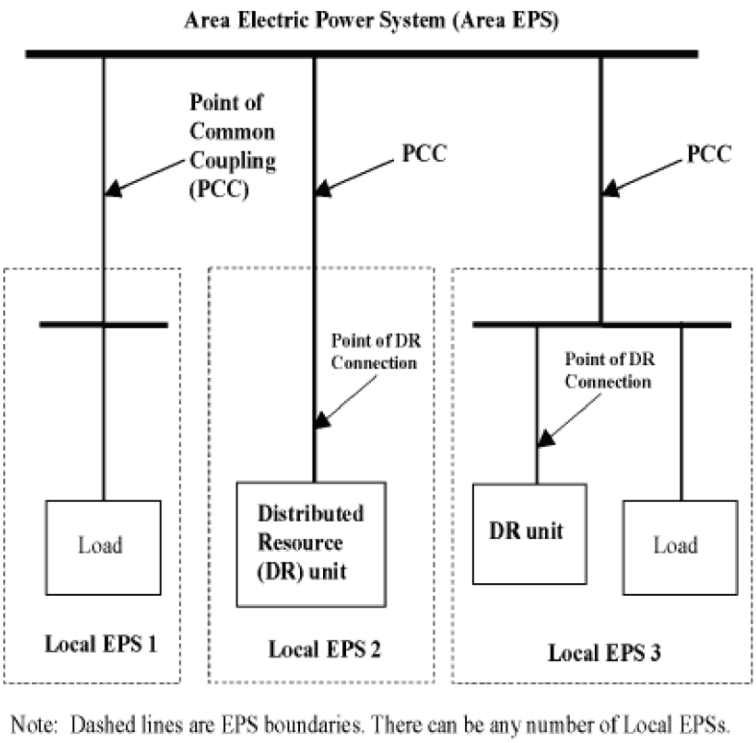


Figure 5.17 IEEE 1547.2 terms and definitions [17]

The equipment used for the connection to the grid varies, depending on the size of the installation and the type of the network (overhead, underground). Nevertheless, the coupling substation comprises the required switching/protection equipment and metering devices, which at a minimum are the following:

- a circuit breaker (a fuse-load switch combination is acceptable for overcurrent protection of smaller installations,
- the interconnection protection system, acting on the interconnection breaker, to isolate the DG installation from the grid upon detection of abnormal network operating conditions,
- metering arrangements for the power and energy produced and consumed by the installation.

In most countries of SEE, DGs can obtain permits to connect to the grid, but only if they meet technical requirements for grid connection and their integration does not adversely affect the reliability of the system. To meet these criteria, an upgrade of the network is often needed, raising the question of how to finance the connection costs. Cost bearing rules define which part of the costs is covered by the generator wishing to be connected and which part by the transmission or distribution system operator. Cost sharing rules define how the necessary cost should be distributed between subsequently connected producers that all benefit from the same reinforcements or new lines.

5.8.1 Albania

On April 30, 2015, the Power Sector Law was adopted by the Parliament (transposition of the 3rd Energy Package). According to the Power Sector Law (Article 37) any connection cost of a power producer including RES power producers shall be borne by the producer. The connection procedures are stipulated by the transmission or distribution codes.

The Power Sector Law tasks the regulatory authority (ERE) to take measures to facilitate the integration of new capacities to the network, in particular removing barriers that may hinder the entry of new participants and producers of electricity from RES. These measures are still pending.

Actually the connection of new producers is made according to the specific rules contained in the transmission and distribution code, but specific provisions for that purpose do not exist in the primary legislation. In the Law on renewable (Article 13/3) it is provided for that upon the request of the producers for connection to the grid, the operators will provide them comprehensive and necessary information including:

- comprehensive and detailed estimate of the costs associated with the physical interconnection to the grid,
- reasonable and precise timetable for receiving and processing the request for the interconnection to the grid,
- reasonable indicative timetable for any proposed grid interconnection.

In 2012 ERE adopted “Rregullore e lidhjeve te reja ne sistemin e Shperndarjes” (“The regulation of new connections”; approved by ERE in February 2012) which regulates the connections of network users to distribution network.

Section 4.1 stipulates the principles of tariffs as follows:

a) Fees for connection to the distribution network are defined in accordance with the following objectives:
    a. non-discrimination,
    b. transparency regarding the use of the distribution network and its integral parts,
    c. development of the distribution network, in order to ensure the preservation of the level of quality of electricity supply,

b) charges for new connections are the same for the whole territory of the Republic of Albania,

c) the guiding principle for the obligation for the implementation of a new connection is - natural or legal person requesting changes in the distribution network, will cover all the costs associated with changing the distribution network to achieve new connection.

Obviously, it stipulates “deep” connection charging of power producers. Section 2.7 outlines:

Sources of electricity will be connected to the distribution network after the DSO have carried out the study of the effects that bring connectivity and that part of the network in the presence of new sources of electricity generation. New sources will preferably be connected as an extension of the existing network 6-10-20-35 kV and if such connection is not possible then it will be to transformer substation. All costs related to the implementation of connection, reinforcement of part of the existing distribution network for purposes of realizing the connection, possible additions in the part of 35 kV and HV substations (when requiring connection to them) shall be borne by the applicant.

Section 2.4 of “Rregullore e lidhjeve te reja ne sistemin e Shperndarjes” also prescribes formal steps in DG connection process:

a) Application will start at Customer Care Center.
b) From the day of application to the day of sign the contract cannot be more than 20 working days.
c) The project must to be sign by Central Technical Inspections (IQT).
d) The project signed by IQT must to be represented to DSO OSHEE.
e) The OSHEE will verify all the documentation if is correct, in case of missing documentation OSHEE will notice the applicant in written in 5 working days.
f) OSHEE will inspect the Generation Facility if is built as project, and will verify the closest point of connections.
g) OSHEE prepares the contract and if applicant agrees he must sign the contract within 10 working days, other way this contract is not valid.
h) When the contract is signed in 2 days OSHEE will give the bill to applicant and after payment, will give the permit to start the development of the project for the connections.
i) After finishing the work applicant notices in writing the OSHEE which shall within 2 working days inspect the installations.
j) Applicant will install the meter in his object with the byers of energy which in this case is KESH (Corporate Electro-Energy of Albania)

Section 4.4 of “*Rregullore e lidhjeve te reja ne sistemin e Shperndarjes*” prescribes the structure of the new connection fees:

a) Fees for a new connection or modification of the existing connection (connection fee) will be calculated taking into account the principles set forth in this regulation.
b) A connection fee will depend on the applicant's requests, the availability of the distribution network at the point of connection, the power reserve (if any) at the point of connection and other features related to its implementation, including the power requested and the voltage level.
c) Connection fee consist of the following: T1, T2, T3, and T4:
   - *T1 - Tuition fee and design approval rating,*
   - *T2 - Services fee for the implementation of the new connection,*
   - *T3 - the power tariff (Lek/ kW power requested),*
   - *T4 - initial attest of electricity meter tariff.*

d) For producers the connection fee shall consist of the following components:
   T1 = 10’000 Lek
   T2 = 100'000 Lek
   T4 = initial attest of electricity meter fee

e) *If the connection of producer will be made at the distribution substation busbars owned by the DSO, DSO will apply the additional fees as laid down in paragraph 4.11.*

The Renewable Energy Law (May, 2013) also obliges the network operators to connect with priority all renewable energy producers to the closest point in the grid. However, the methodology for grid connection of renewable energy producers and a standard connection agreement have not yet been adopted by ERE due to the postponement of the entry into force of the Law.

ERE is tasked to approve the necessary procedures and documentation for the connection of generation facilities to the grids. Alignment of the existing procedures for connection of renewable producers to the transmission and distribution networks and methodologies for establishing the cost of connection in order to comply with the requirements of the Power Sector Law adopted in 2015 is pending.

5.8.2 Croatia

In conformity with the "Rulebook on determination of the compensation for the connection to transmission and distribution networks and for increase in connected load" (March 2006), proposed DG shall carry real costs of a connection to DSO's network, comprising:

- actual costs of building the connection to distribution network,
- actual costs of reinforcements in the existing network that will be required to support the new generation connection, i.e. costs aimed at providing a part of technical conditions in the network. Creation of network technical conditions shall be realized by the means of the investment in the network of the connection voltage level and/or the first higher voltage level above the connection voltage,
- actual costs of building and fitting of accounting metering/measuring point.

Connection construction includes:

- drawing up a grid connection study providing the optimal technical solution for the construction of connection to HV network,
- drawing up required investment and technical documentation,
- acquiring rights to construct and easement rights,
- obtaining all required permits to construct/build a connection,
- execution of construction works, including necessary materials and equipment,
- execution of electrical fitting, including necessary materials and equipment,
- equipping metering point with metering equipment,
- testing and
- connection to network.

Establishing of technical conditions in network includes:

- drawing up a grid connection study providing the optimal technical solution for the connection, with the exception of connection to LV network,
- drawing up required investment and technical documentation,
- acquiring rights to construct and easement rights,
- obtaining all required construction permits,
- execution of construction works, including necessary materials and equipment,
- execution of electrical fitting, including necessary materials and equipment and
- testing and commissioning.

It could be observed that the grid connection study is performed by DSO only for interconnections to MV network, although in practice certain analyses are also performed for interconnections to LV network within the procedure named “issuing of techno-economic data” (*Figure 5.18*).

When interconnecting producer's facility to the network, the process of acquiring construction rights and easement rights that refer to the construction of connection to the network and establishing technical conditions in the network, shall be governed by the DSO. All expenses shall be paid by producer.

The grid connection study for DG facility (EOTRP)

Pursuant to “Rulebook on determination of the compensation for the connection to distribution networks and for increase in connected load” (March 2006), the DSO shall determine the technical conditions and expenses for connecting producer's facility to MV network on the basis of the grid connection study for DG (i.e. EOTRP).

Drawing up of a study shall be within the competence of DSO, while the expenses of drawing up a study shall be covered by producer (investor). In case of interconnection of producer's building to the distribution network, those expenses shall be recognized within the connection compensation.

The study shall be carried out before Provisional Grid Connection Authorization is issued, guided by the fact that the Provisional Grid Connection Authorization is based on the optimal technical solution for connection provided by the study.

The Provisional Grid Connection Authorization (PEES)

The provisional grid connection authorization (i.e. PEES) shall be granted in order to assess the feasibility of connection, and to determine the technical, economic and other conditions for interconnection to the grid. The provisional grid connection authorization shall be granted by the DSO. If location permit is required, the provisional connection authorization shall be granted in the process of issuing the location permit at the request of the authority responsible for issuing the permit.

Within its validity period, the provisional grid connection authorization is a binding document for its issuer (DSO). This means that, after terms comprised in the provisional grid connection authorization and connection contract are fulfilled, the DSO is obliged to build the connection and permanently connect user to the distribution network. However, no generation facility may be connected based on a provisional grid connection authorization. Essential preconditions for network user connection to the DSO distribution network are:

- network user written claim for issuance of the (final) grid connection authorization and connection; claim shall have the initial (start-up) parallel operation testing program enclosed which shall be previously agreed between DSO and network user,
- all terms/conditions comprised in the grid connection contract shall be fulfilled,
- permit for building power plant shall be issued,
- built and fully operational connection and necessary network reinforcements (DSO obligation).

The provisional grid connection authorization shall be valid for two years from the date of issue. The provisional grid connection authorization shall expire within two years from the date of issue unless a grid connection contract is concluded within such period, the obligations under the connection contract have been complied with and the application for issuing the connection authorization and for connection have been submitted. When the request for extension of the validity of the provisional connection authorization is submitted prior to the expiry of the validity period, the validity of the provisional connection authorization may be extended for additional two years.

Based upon the provisional grid connection, the grid connection contract shall be concluded between the DSO and network user. This contract shall regulate the conditions for interconnecting to the distribution grid and all particulars relating to the construction of the connection which are the subject of the “General Conditions for Electricity Supply” (2006) (e.g. grid connection contract shall specify committed capacity).

In conformity with the DSO unofficial guideline for the implementation of the old “General Conditions for Electricity Supply” (2006) and “Rulebook on determination of the compensation for the connection to transmission and distribution networks and for increase in connected load” (2006), after fulfillment of all obligations comprised in the provisional grid connection contract, and at the request of network user, the DSO and network user sign the grid connection contract. The validity period of the grid connection contract shall be equal to the validity period of the provisional grid connection authorization.

The Provisional Grid Connection Contract

Based on the provisional grid connection authorization (PEES) contractual parties may agree a provisional grid connection contract governing mutual relations in arranging for conditions in the grid and the connection for connecting the building prior to and including the issuing of necessary permit for building.

Namely, in case of a complex connection to the distribution network implying that cost of connection cannot be predicted with confidence at the time of issuing the provisional grid connection authorization, and also in a case of a complex reinforcements in the existing network that are required to support the new generation connection, it is a common practice for DSO to conclude a provisional grid connection contract. In practice the provisional grid connection contract is governing preparation fees of relevant documents governing building of connection to distribution network and reinforcements in the existing network that will be required to support the new generation connection. Thus costs stated in the provisional grid connection contract are covering:

- preparing the necessary investment and technical documentation,
- obtaining the easement and construct rights,
- issuing the necessary permits for building,
- land purchase/acquisition.

According to previous practice, obligations stated in the provisional grid connection contract are deemed fulfilled upon issuing the necessary permits for building of all facilities stated in the provisional grid connection contract. Upon the contract enforcing, within the validity period of the provisional grid connection authorization, network user is obliged to enter into the grid connection contract with DSO. This contract details comprehensive connection conditions, for example (General Conditions for Electricity Supply, Article 28):

- the connection charge (amount of the grid connection fee),
- payment dynamics (due date and schedule of payment of the connection fee),
- deadline for works which are subject to the contract,
- deadline for connecting,
- conditions for installing the connection,
- conditions for energizing the connection,
- contract period, etc.

The rights and obligations of network user

Network user is responsible for constructing its generation facility in accordance with the provisional grid connection authorization, grid connection contract, technical conditions on connection determined by DSO and current technical regulations and standards that are based on the principles of limiting the negative effect on distribution and transmission network (e.g. emission of higher harmonic components, flickers, asymmetry etc.). Also, user is responsible that its facility and installations are implemented, maintained and operated in a way their effect on the distribution network, i.e. disturbances and interference they may cause, are within the limits that do not compromise prescribed power quality.

Network user is responsible for all the damage towards other customers or producers, as well as towards TSO or DSO, which is due to the disturbances or interference caused by its power facilities or installations, and therefore user is obligated to provide DSO with all the technical and operational data in order to determine and verify user's connection.

User is responsible for ensuring that the staff working in the facilities have appropriate qualifications, that they are qualified to work in a safe manner, possess all the necessary personal protective equipment, in accordance with current technical regulations and requirements relating occupational safety.

User is obliged to pay connection charge for its generation facility to DSO anticipated when creating technical conditions in the network for assuring connection in accordance with “Rulebook on determination of the compensation for the connection to transmission and distribution networks and for increase in connected load” (2006).

According to previous practice, the formal investor into the connection is DSO, and connection charge, that according to the Rulebook has to be paid by the user, is intended to finance the construction of connection and creating all the technical conditions (reinforcements in the existing network) that are required to support the new generation interconnection. DSO becomes investor of the connection by concluding the provisional grid connection contract with network user.

User is responsible for land acquisition, associated property and legal issues related to the land where connection is to be carried out including all the physical planning documentation, and allowing DSO undisturbed construction and maintenance of the connection, based on the easement and construct rights.

In this sense network user shall (network user bears the costs):

- carry out the parcelation of land to form a plot necessary for placement of connection facility,
- sign contract with DSO establishing right of servitude for the purpose of building power lines on land owned by network user,
- sign contract with DSO regulating acquisition of property rights for plot necessary for placement of connection facility,
- lay down control and 10(20) kV cable between power plant and connection facility.

The rights and obligations of DSO

Preparation (obtaining required documentation and permits, easement and construct rights), operation (tests and commissioning) and construction of the connection (to the property boundary of network user including accounting metering point) and necessary network reinforcements are the responsibilities of DSO.

DSO is obliged to permanently connect user's generation facility after following conditions are fulfilled:

- provisional grid connection authorization is issued,
- grid connection pre-contract and contract are concluded,
- all the terms stated in provisional grid connection authorization and grid connection contract are fulfilled,
- building permit or confirmation of the main project (building approval) is issued,
- connection facility is built, tested and put out under the voltage,
- user's generation facility is built,
- internal technical examination of the connection is performed, and any possible removal of defects identified is made,
- functional testing and verification of connection is performed, and any possible removal of defects identified in the report is made,
- use permit of grid connection is issued to DSO,
- study on concept and settings of the protection system is made and disclosed to DSO,
- study on power plant/facility impact on the network is made and disclosed to DSO,
- (final) grid connection authorization is issued,

- power purchase agreement between user and market operator is concluded,
- supply contract between user and supplier is concluded,
- grid usage contract between DSO and user is concluded,
- ancillary services contract between TSO and user is concluded (not a requirement, depends on the needs of TSO and possibilities of a producer),
- operation management contract between DSO and user is concluded,
- functional testing and verification of the generation facility is successfully performed and any possible removal of the defects identified in the report is made,
- use permit of the user's facility is issued and submitted to the DSO.

Formally, there are many steps until final implementation and commissioning of the interconnection (*Figure 5.18*). As new Distribution Code is being drafted, DSO is working on simplified procedure for small power plants <30 kW (*Figure 5.19*).

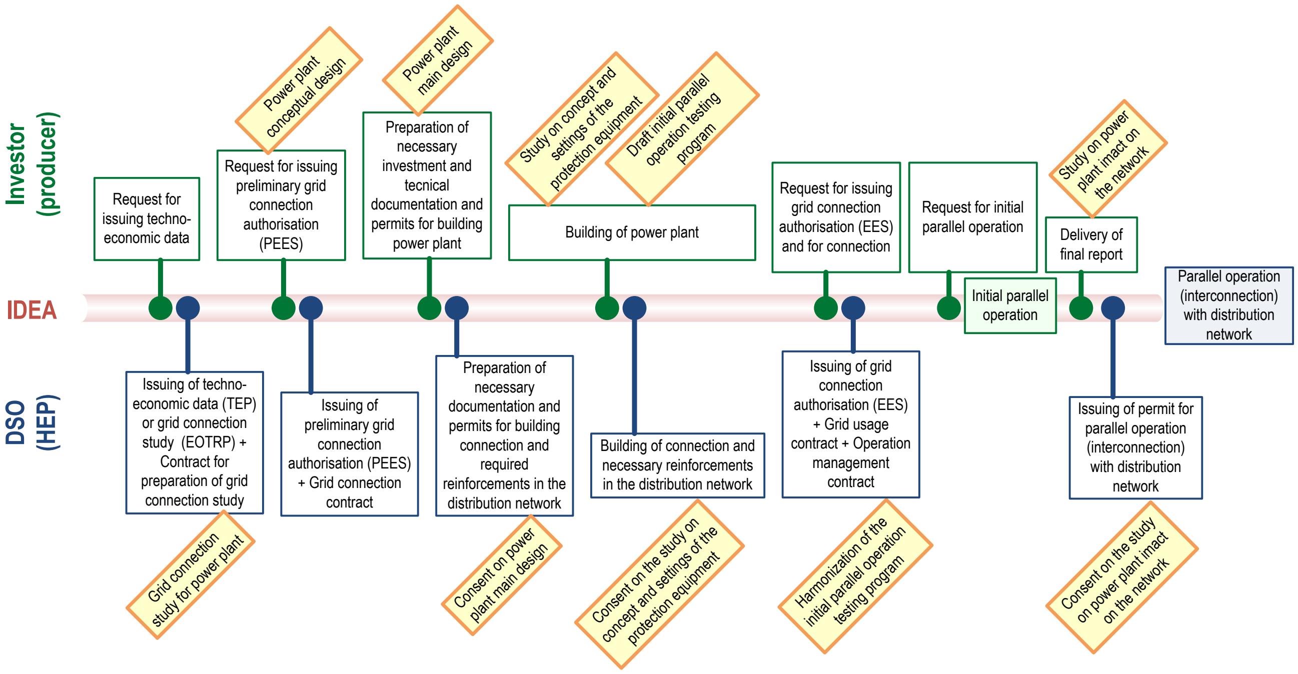


Figure 5.18 Formal steps in DG connection procedure – the case of Croatia (HEP DSO)

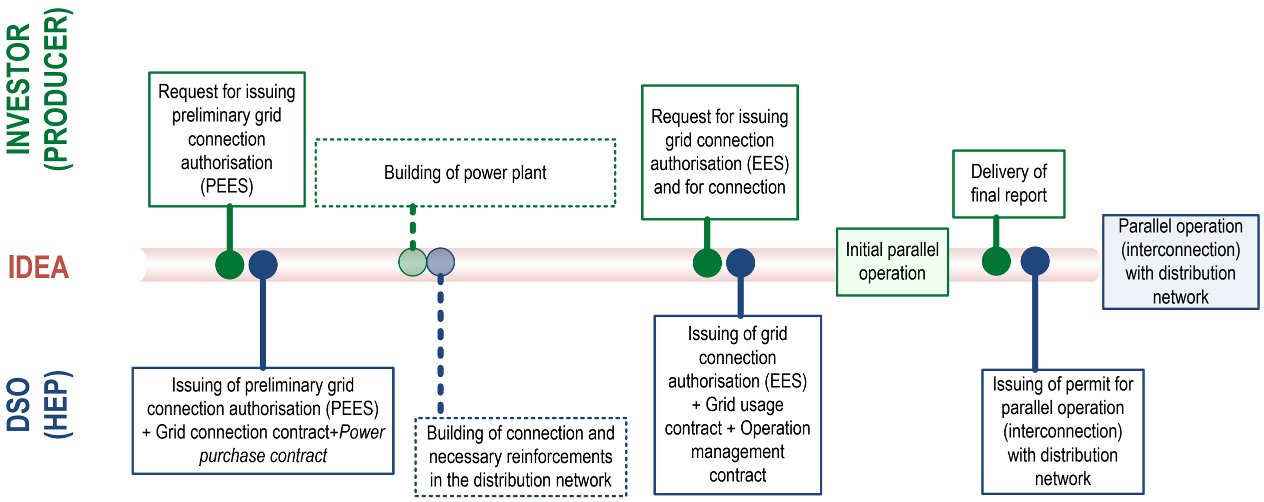


Figure 5.19 Formal steps in DG connection procedure – the case of Croatia (HEP DSO) – unofficial simplified procedure for PVs under 30 kW

The risk of delay in realization of connection and also necessary network reinforcements (DSO obligation) within validity period of provisional grid connection authorization is conditioned by:

- fulfillment of payment dynamics as provided by grid connection contract,
- duration of the procedure for obtaining necessary documentation/permits, the procurement of equipment, contracting works and connection building.

There is a standard provision in the provisional grid connection authorizations by which expected time for realization of the connection is two years from the date of issue of all necessary documentation/permits for connection and required reinforcements in the network. This is to allow for adjournments which DSO could not control (i.e. unforeseeable problems), such as approvals of administrative bodies, issuing permits, resolving property rights relations, on-site events, etc. DSO is obliged to timely communicate to network user on all adjournments and, if necessary, even to specify new deadline for connection, different technical option and deadline for connection, and/or to terminate grid connection contract.

In this sense, there is no strict obligation for DSO to energize the connection (i.e. connection being fully operational) within the validity period of the issued provisional grid connection authorization. In practice, grid connection pre-contract and grid connection contract specify terms within which DSO needs to complete works on connection and required reinforcements in the network. These are usually conditioned by fulfillment of payment dynamics by network user.

Connection charge

Pursuant to “Rulebook on determination of the compensation for the connection to transmission and distribution networks and for increase in connected load” (2006), connection charge borne by producer shall cover:

- actual costs of building the connection to distribution network,
- actual costs of reinforcements in the existing network that will be required to support the new generation connection, i.e. costs aimed at providing a part of technical conditions in the network. Creation of network technical conditions shall be realized by the means of the investment in the network of the connection voltage level and/or the first higher voltage level above the connection voltage,
- actual costs of building and fitting of accounting metering/measuring point.

There shall also be added costs of acquiring easement and construction rights for the construction of connection and required extension of the grid which are not part of connection charge, and which are also borne by project investor.

Construction of connection and required reinforcements in the existing network shall be based on the application of standardized equipment and technical solutions and shall be within the competence of distribution system operator.

Unit prices of goods, works and services set by public tenders and standardized work standards shall be used for the calculation of actual connection costs. DSO shall make them publically available.

DSO shall lead the process of acquiring rights to construct and easement rights in the interest of producer (proposed network user). All expenses have to be transparent.

It is a common practice for DSO to conclude a provisional grid connection contract. In practice the provisional grid connection contract is governing preparation fees of relevant documents governing building the connection to distribution network and reinforcements in the existing network that will be required to support the new generation connection.

Upon the provisional grid connection contract enforcing, within the validity period of the provisional grid connection authorization, network user is obliged to enter into the grid connection contract with DSO. This contract details comprehensive connection conditions including the connection charge (amount of the grid connection fee), and payment dynamics (due date and schedule of payment of the connection fee).

Pursuant to DSO unofficial guideline for the implementation of the old "General Conditions for Electricity Supply" (2006) and "Rulebook on determination of the compensation for the connection to transmission and distribution networks and for increase in connected load" (2006), connection charge determined by the grid connection contract is subject to change within the validity period of the contract, due to change in estimated:

- costs of acquiring rights to construct and easement rights,
- unit prices of goods, works and services set by public tenders and standardized work standards.

Within the validity period of the contract, DSO reserves the right to revise connection charge provided by concluded grid connection contract. In this case DSO is obliged to offer adequate clause to a grid connection contract to the proposed network user. If network user does not sign offered clause to a contract within 30 days, grid connection contract will terminate.

Obviously, costs provided in the provisional grid connection contract and the grid connection contract are estimated based on previous data about unit prices of goods, works and services set by realized public tenders and standardized work standards. Actual costs of connection and costs of required reinforcements in the network borne by producer are determined after collaudatio of performed works and fulfillment of contractual obligations (i.e. carried out public tenders). If past experience is any guide, costs provided by grid connection contract usually represent upper limit of reimbursement borne by producer.

5.8.3 Kosovo

In Kosovo, DSO is not legally obliged to connect RES with priority. In line with the RES Directive, the Energy Law (2010) only states that:

- TSO and DSO shall **establish and publish standard rules** on who bears the costs of technical adaptations, such as grid connections and grid reinforcements, necessary to integrate new electricity generation feeding electricity produced from **RES** into the interconnected system. Such rules shall be submitted for approval to the regulatory authority (ERO), shall be consistent with the Energy Strategy and shall be based on objective, transparent and non-discriminatory criteria, taking particular account of all the costs and benefits associated with the connection of these producers to the system,
- TSO and DSO shall provide any new electricity producer using RES or co-generation wishing to be connected to the system with a **comprehensive and detailed estimate of the costs** associated with the connection for which estimate the system operator **may levy a charge** that reflects its reasonable costs,
- ERO shall ensure that transmission and distribution fees for connection and for use of the transmission and distribution systems do **not discriminate** against electricity from RES, including in particular electricity from RES produced in peripheral regions, such as regions of low population density.

Electricity Law (2010; article 28) stipulates the obligation of the DSO to provide connections, subject to the party seeking the connection and:

- having electrical switchgear constructed within the boundaries of its property which satisfy the technical and operational safety requirements,
- meeting the conditions for connection to the transmission or distribution system, including the Grid Code and Distribution Code as applicable,

- having signed a written agreement with the Distribution System Operator in respect of the connection, including the regulated connection charge, and the use of system charge where applicable,
- having paid all amounts due in the agreement for the connection.

The terms and conditions for the connection to the transmission or distribution systems are provided in the published Grid code and Distribution code.

According to Rule on General Condition in Energy Supply (2011; article 7), TSO and DSO shall develop connection charging methodologies in accordance with Tariff methodologies approved by ERO. Connection Charging Methodology is still in the drafting process.

According to Rule on General Condition in Energy Supply (2011):

- producer application has to be submitted directly to the system operator,
- after registering the application for connection (or modification of connection), the system operator shall make necessary arrangements to study technical requirements of the connection, if necessary visit the premises subject to the application and draft and deliver a written connection offer.

Although in the Energy Law or Electricity Law there is no provision about requirement for TSO/DSO to bear the costs of technical adaptations, Distribution Charging Principles, issued by ERO in 2012 (in article 12 - Connection of generation) specify:

- applicants for the connection of new generation, or increases in the connection capacity for existing generation, should pay **shallow connection charges** set so as to recover the direct costs of the provision of the connection to the **nearest suitable point on the distribution system**, including any metering and step-up transformers necessary to enable the connection but should not include the cost of any reinforcement of the system that may result from the connection upstream of the point of connection,
- in line with Article 8 of the ERO "Rule on the support of electricity for which a certificate of origin has been issued and procedures for admission to the support scheme", the DSO is allowed to **levy a charge**, which shall be approved by the Regulator, in respect of applications submitted **for the carrying out of an assessment of the impact** of the proposed development of a specified generating unit which is to be connected to distribution network.

The Methodology should include a list of information that will be required of applicants requesting connection to the distribution system, including forms which applicants will be required to complete.

Where the DSO has received a formal connection application containing all information required under the approved Charging Methodology, it should provide a **formal offer to connect** the applicant within the time limits specified in Article 9.7 of the Rule on General Condition in Energy Supply (30 days LV; 90 days MV).

As indicated in [11], the average time schedules until signing connection agreement of 2-3 months is "normal" and there are at the moment no plans for changing the procedure.

The DSO should, at the request of a person interested in a new or modified connection, provide an **indicative and non-binding quotation** to assist that person to budget the likely financial costs of its project.

Any **indicative quote** mentioned above should not require the DSO:

- to complete any site studies or system studies, or
- to obtain any supplier's quotation for the necessary lines, plant or equipment likely to be required to enable the connection to be made, or to obtain any rights of way,

and the DSO should not be required to carry out the steps envisaged above until a formal connection application has been received.

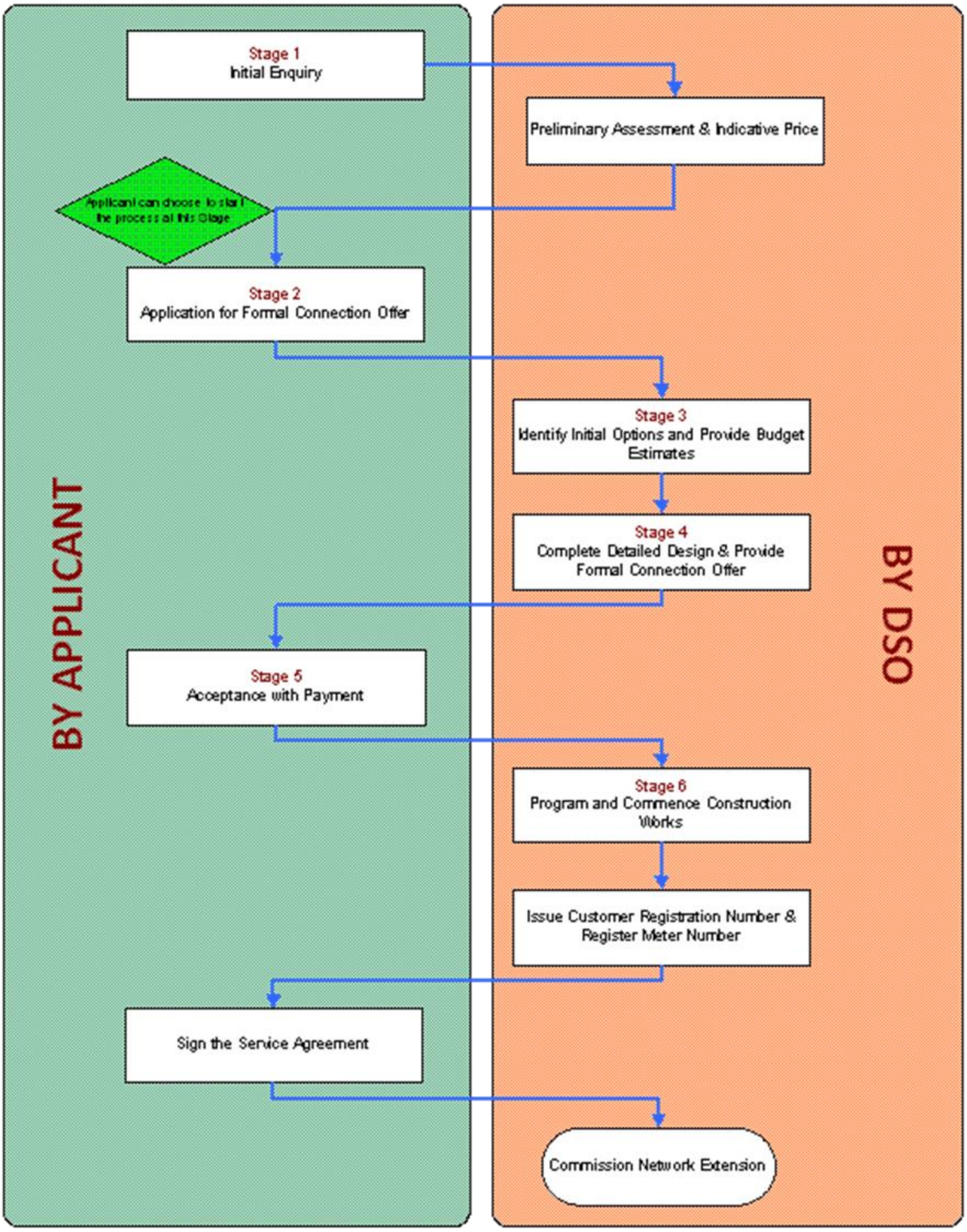


Figure 5.20 KEDS new connection steps

The deadline for the submission of connection offers may be extended in the event of a complex connection, implying a prior technical study of a network extension or any similar reason according to the provisions of the Grid or Distribution code or other applicable codes (i.e. the study must be completed within 90 calendar days from the date of delivery of the application for connection and the connection offer must be delivered within 30 days of the completion of the relevant study).

The Connection Charging Methodology shall, in the event of a dispute over the terms of a connection offer, provide for the applicant to **conduct their own technical study at their own cost**, and for the system operator to facilitate any such study through the provision of the necessary information for which **an appropriate charge may be made.**

The formal offer should contain the date by which the connection works will be completed. Where the DSO and the applicant so agree, the formal offer may include terms for the payment of interest for failure of either party to complete its part of any necessary works or to provide any necessary consents and which leads to delays and costs for the other party.

Within the period specified in the connection offer the applicant accepts the offer by submitting a signed draft **connection agreement** to the supplier and pays the relevant connection charges to the benefit of system operators. The connection agreement shall be concluded on the day of delivery to the system operator.

Upon conclusion of a connection agreement, the system operator shall establish the connection as specified in such agreement. Upon establishment of a connection the system operator shall **issue a report**, confirming that the connection has been made according to the terms and conditions of the connection agreement, and submit it to the system users.

As indicated in [11], the construction of the grid connection may be done by developer according to designs approved by system operator. After successful construction, supervised by system operator, the grid connection installation is handed over to system operator for operation and maintenance. Technical adaptations of the grid necessary for the connection are going in grid development plan and shall be executed before the construction of RES generator.

According to [11], new Connection Charging Methodology **shall establish that the subsequently connected generators will share the cost of connection** with the initially connected generators, proportional to the installed capacity.

No simplified procedures are applied for small scale decentralized energy generation from RES (i.e. solar panels in buildings). The implementation of simplified procedures is envisage in accordance with the Administrative Instruction on use and support to RES generation.

5.8.4 Macedonia

Formal steps in the connection procedure for DGs in Macedonia are:

- request for consent for connection to the distribution grid,
- conclusion of a contract for connection between the system user and the DSO,
- putting the connection under voltage.

The procedure for determining the connection point and technical solution for connection of the distributed generators is elaborated in the Distribution Code. In the phase of determination of connection point and optimal economically technical solution, DSO is obliged to prepare appropriate analysis of the situation in (impact to) the distribution network.

DSO is obliged to prepare the data for the technical characteristics of the investigated network which are basis for preparation of the above mentioned analysis. The representative of the distributed generator has right to participate in the process of deriving the solution for connection; DSO shall invite the representative and present the findings and the analysis needed for determination of the connection to the network. Together they try to find mutual agreement for the technical solution.

If requested by the investor, enclosed to the Consent for Connection DSO is obliged to submit all necessary data used for performing of the analysis. With this, the distributed generator has possibility to make its own calculation and analysis. If in accordance to the calculation and analysis, the distributed generator finds that there is a possibility for more efficient solution for the connection which satisfies the conditions set in the Distribution Grid Code, it may file for appeal in the Energy Regulatory Commission.

Energy Community in its annual report for FYROM (2015) [3] for Macedonia observed:

To comply fully with Article 16 of Directive 2009/28/EC, EVNM as network operator has to become more transparent towards the producers of renewable energy with regard to information on the estimated costs and timeframe for connections. The regulatory authority ERC has to ensure that rules for connection and access to the networks are implemented in a non-discriminatory and objective way, as there are cases of doubt.

Based on questionnaire response, EVN Macedonia continuously works on improving the rules and procedures for connection of the users (consumers and generators) to the distribution networks which derive from the application of the existing regulation. To improve connection procedures the Distribution Network Codes have been amended three times during 2014. With these amendments the application form for connection to the grid has been simplified. The initiation of the process for connection to the grid before the construction permit is issued is now possible, thus shortening the procedure. In addition the procedure for connection of the producer is more transparent, technical criteria are defined with greater

The Energy Law is expected to be amended soon for its full harmonization with the RES Directive.

Publically available information for new connection:

- on the EVNM web site is available Guideline for connection of the distributed generators https://www.evn.mk/Business-customers/New-connection-fo-distributed-producers.aspx.
- in addition to the abovementioned guidelines, the Distribution Code is published in the Official Gazette of the Republic of Macedonia and on the web site of the Energy Regulatory Commission,
- the Energy Regulatory Commission also has prepared and published announcements for the procedure for connection to the distribution network through all types of connections,
- the call centres of EVN Macedonia are available for all questions for information concerning the connection procedures.

According to the Network Codes, producers shall bear all connection and technical adaptation costs pursuant to a methodology stipulated therein. However, the Energy Law allows the regulator to oblige the competent operator to cover the connection costs of preferential generators and recover the costs incurred as part of the regulated services price when needed to provide incentives to promote RES or when necessary to attain the targets set out in the Government's Renewable Energy Strategy. Cost sharing rules governing how costs should be distributed between subsequently connected producers that benefit from the same reinforcements and new connection facilities are defined in the Distribution Network Code.

Currently for the distributed generators up to 30 kW the connection point might be on the low voltage distribution network and for the distributed generators up to 50 kW directly in the transformer station if the technical conditions are satisfied. It is expected that after adoption of the new Energy Law, in which will be transposed the RES Directive 2009/28/EC, the rules for connection to be amended accordingly.

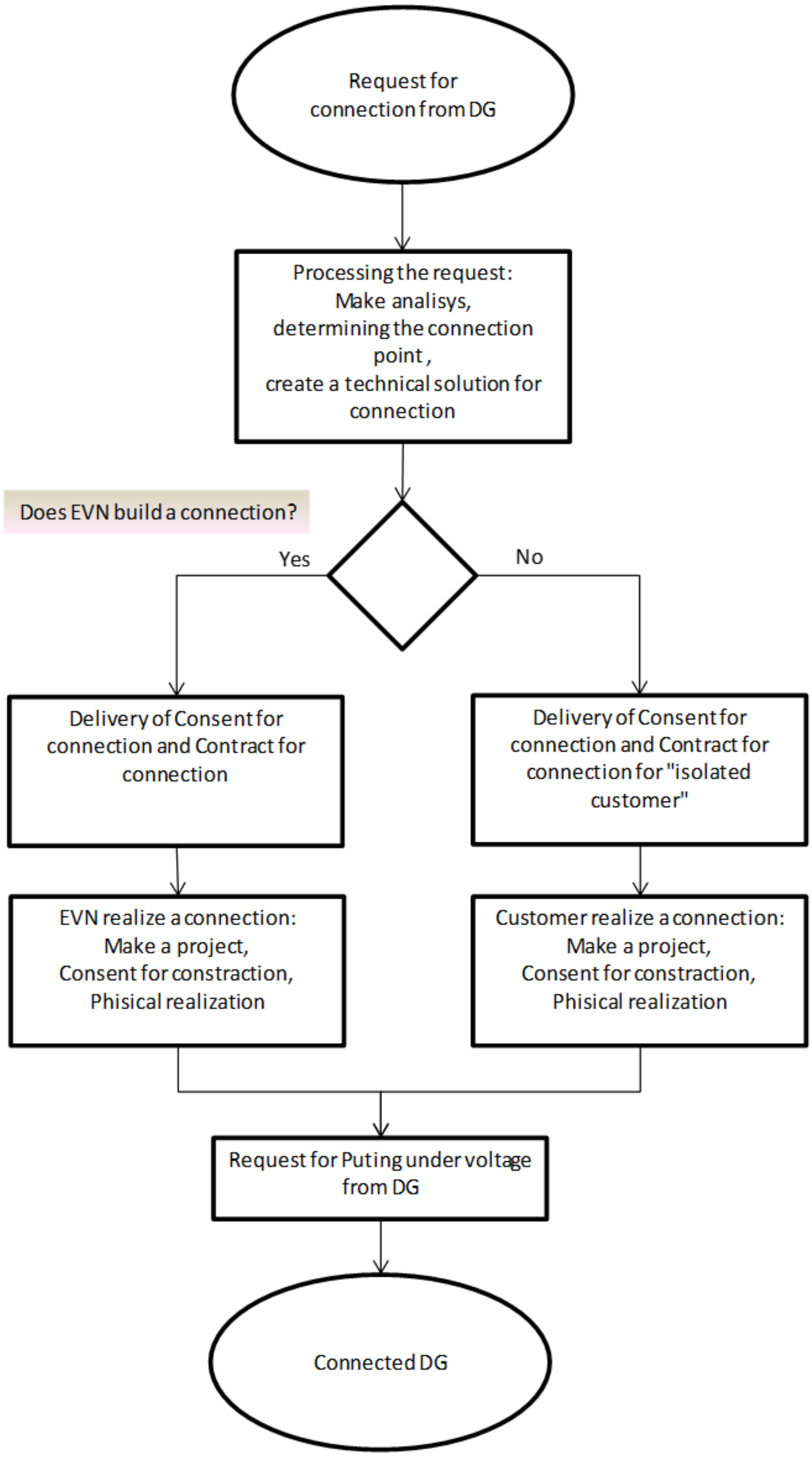


Figure 5.21 Steps in the connection procedure for DGs in Macedonia (EVNM)

5.8.5 Serbia

The five Distribution Codes (2009) were amended in 2014.

In accordance to RES Directive, developers are entitled to build the connection to the grid, calling for a tendering for construction works if they choose so. They have the right to deduct the respective cost of construction from the total connection costs that are calculated in accordance with a methodology adopted by regulatory authority (AERS).

The DSO is obligated to decide on the application for approval for the connection of a power within sixty days from the date of receipt of written request. DSO is obligated to issue a positive decision, if all conditions are fulfilled, on the basis of the technical report, calculation of costs of connection and other available documents.

DSO will approve the connection if it determines that the equipment and installations of the facility to be interconnected fulfil conditions prescribed by the laws, technical and other regulations regulating the conditions and manner of exploitation of these facilities. The system operator is bound to connect the facility of the electricity producer to the distribution system within 15 days from the date of fulfilment of the following conditions:

a) conditions from the approval to connect,
b) acquired operation permit for the facility or that the equipment and installations of the producer’s facility meet technical and other prescribed conditions,
c) arranged balancing responsibility and access to the system at the point of commissioning.

In the forthcoming period, it is envisaged that the connection to the power grid is included within the analysis of possibilities of simplification of procedures, as well as that the procedures concerning the required documentation and deadlines are harmonized for all power distribution system companies.

The procedure for the connection of the electricity producer’s facility does not foresee any right of priority for the facilities using RES.

During the acquisition of the right to construct and the right to engage in the activity of electricity production, the investor must submit the application to the system operator three times, i.e.:

a) for obtaining the energy permit he must obtain the opinion of the system operator on conditions and possibilities for the connection to the system,
b) before the issuance of the location permit the investor must obtain the conditions for the connection to the electric power grid and
c) after obtaining the operation permit he should execute the connection of the facility (power plant) to the electric power grid.

The procedure of the construction of facility does not specifically define the relation and coordination between the system operator and other institutions in charge of issuing permits and approvals. In the forthcoming period, in compliance with the activities aimed at establishment of one-stop-shop for RES, the link between the system operator and other institutions competent for issuing permits and approvals during the procedure of construction of the facility shall be established.

The procedure for the connection of the electricity producer’s facility does not foresee any priority connection rights for the facilities using RES.

The Energy Law (2014), define that the complete connection, including metering unit, belongs to the distribution company which is responsible for its construction and maintenance, and the costs of connection are to be borne by the applicant (as foreseen in the Article 132). Methodology adopted by the Energy Agency of the Republic of Serbia (AERS) details criteria and determination of the costs of connection to the distribution system.

Types of connections are:

a) standard connection (individual and group standard connection), and

b) custom connection (refers to the producer).

Custom connection (non-standard) is any connection which, due to its complexity, does not allow standardization of solutions and averaging of the construction costs. Currently, all DG connections are regarded as non-standard.

Costs of the connection are determined on the basis of the following criteria:

a) technical characteristics of the connection,
b) type and scope of works required for the connection of the facility to the distribution system and other conditions related to the construction, or execution of works on the connection (which are defined on the basis of approved capacity, voltage level of the grid to which it is connected and the distance to the existing grid, number of phases, number of metering units, type and cross-section of the power line, type of equipment, devices and material installed pursuant to the technical conditions for connection defined by the technical regulations and Distribution Code, as well as the need of elaboration, or obtaining of the design and other documentation for construction of the connection, or execution of works).

In general costs of the connection comprise:

a) costs of equipment, units and material,
b) costs of execution of works,
c) costs of elaboration of the design, obtaining of necessary documentation and creating other conditions for construction of the connection,
d) part of the system costs occurred due to the connection of the facility, depending on the approved connection capacity.

If, due to technical conditions of the connection, the custom (non-standard) connection also includes the construction of an electric power system facility solely for the needs of the applicant, costs of construction of the connection on these grounds are determined in the amount required for the construction of that facility with the capacity requested by the applicant or for the first higher standardized rated capacity of the transformer and the first larger standardized cross-section of the power line.

Pursuant to the Methodology, the electricity producer bears only the costs of construction of the connection, and is free from paying costs of development of a part of the system (i.e. „shallow" scheme). However, based on the EPS response to the study questionnaire, costs are determined on a case-by-case basis and can differ considerably.

Pursuant to existing legislation, there is no difference in prices of the connection to distribution system in different regions (i.e. poorly populated or well populated places).

There is publically available price list for: issuing DSO opinion on the conditions for connection, performing analysis of optimum conditions of connection, so called extension of opinions regarding connection and issuing conditions and the design of connection.

DSO issues, on the basis of the methodology, its own act where it sets the costs of the connection. During the procedure of obtaining approvals for the connection and the connection itself, no financial deposits are envisaged.

The existing regulations and procedures defined for connecting to distribution system do not provide for the attribution (sharing) of costs between subsequently connected producers. The producer subsequently interconnected is under no obligation to participate in the reconstruction of part of the costs previously incurred by the producer(s) interconnected to the same part of the network (connection point).

On the following web site, for example http://www.elektrovojvodina.rs/sl/korisnicki_servis/Uputstvo-za-priklucenje-elektrane-na-distributivni-sistem-elektricne-energije, there are comprehensive guidelines and information related to the interconnection of distributed resources to distribution network. Besides guidelines, there are standard request forms related to connection procedure.

5.8.6 Bosnia and Herzegovina

District of Brcko

Formal steps of the connection procedure:

- Location approval
- Grid connection authorization
- Connection contract
- Grid usage contract
- Supply contract/Power purchase contract
- Inspection - generation facility, connection facility and connection
- Interconnection commissioning
- Declaration on the connection

Connection charge cost components are:

- grid connection study,
- study of required investment and technical documentation for establishing of technical conditions in the grid,
- actual costs of building the (particular non-standard) connection to distribution network,
- actual costs of required additions/upgrades in the distribution system.

For RES and co-generation producers <10 MW, General terms and conditions of electricity supply (2014) oblige DSO to perform studies (previously mentioned) free of charge. All other producer bear all cost components. It could be observed that in EDB “deep” connection charging is applied.

Republic of Srpska

In March 2014 the DSO, with the consent of the Regulatory Commission, adopted *Rulebook defining the method, terms and conditions and procedure for connection to the distribution network of generation facilities which use renewable energy sources and efficient co-generation*.

The Rulebook prescribes:

- minimal terms and conditions for interconnection to the distribution network:
    - steady-state thermal constraints,
    - stationary operation voltage boundaries,
    - short-term voltage changes due to switching operations (i.e. rapid voltage change),
    - flickers,
    - harmonics,
    - short circuit capacity,
    - voltage unbalance,
    - DC component,

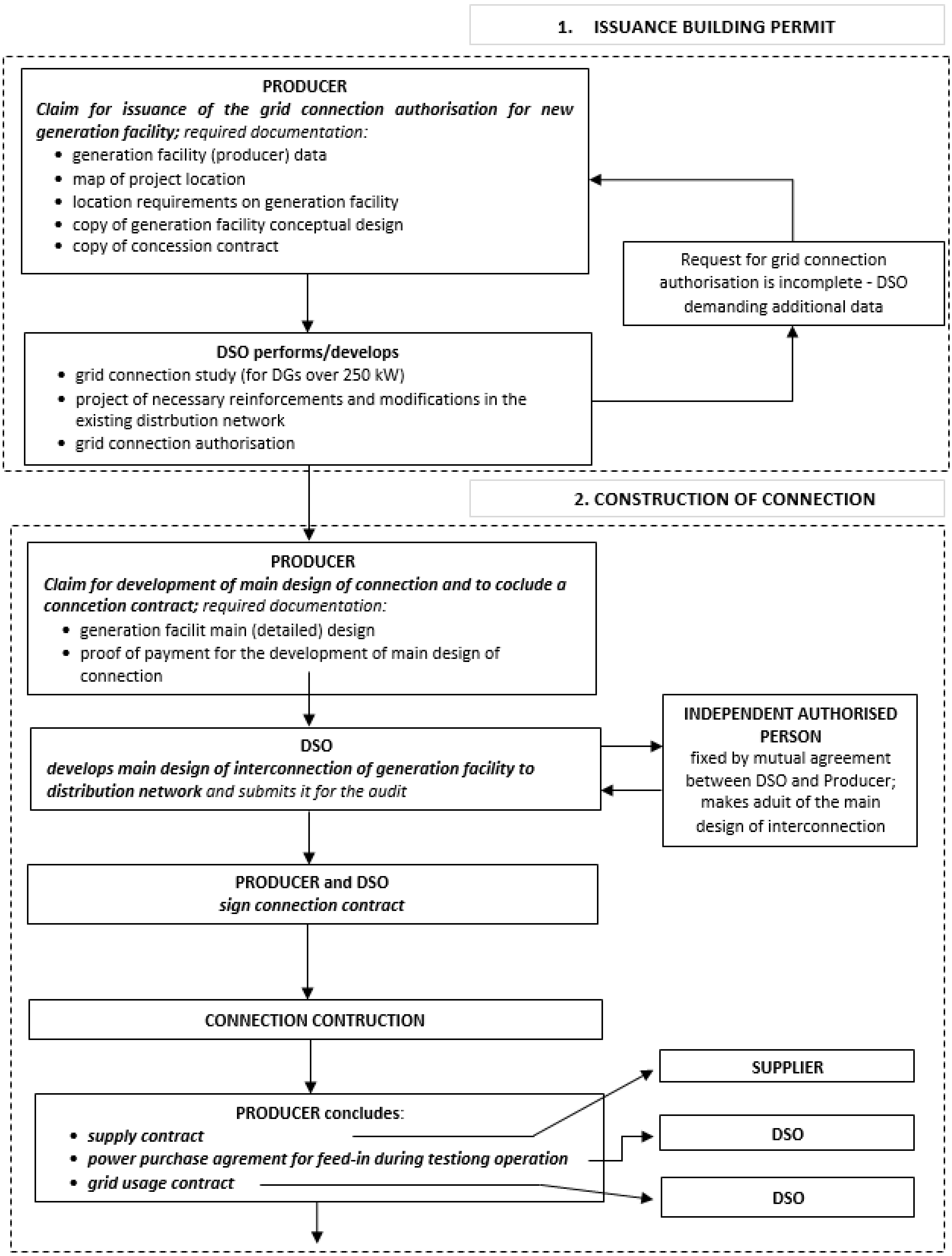
    - commutation notches,
    - ripple control system interference,
- minimal terms and conditions for parallel operation with distribution network:
    - general terms (i.e. protection against unintentional islanding, reconnection, “coupling” circuit breaker in the connection facility),
    - active power control,
    - synchronization,
    - reactive power control,
    - behaviour in the event of disturbance,
- minimal terms and conditions for interconnection facility:
    - general terms (i.e. types of connection, point of connection, types of operations – isolated, islanded, parallel with distribution network),
    - connection requirements (i.e. “n-1” criteria, connection components,..),
    - connection line,
    - connection facility (i.e. isolation/protection circuit breaker in the connection facility, surge arresters),
- metering requirements (i.e. measuring devices, meters, instrument transformers, particularities regarding RES under support scheme and net-metering),
- protection requirements,
- connection procedure:
    - documentation,
    - grid connection authorisation (and analyses performed within the connection procedure),
    - design of connection,
    - connection contract,
    - supply contract,
    - power purchase contract,
    - grid usage contract,
    - internal technical examination of the connection,
    - initial parallel operation,
    - inspection of the generation facility,
    - permanent parallel operation of generation facility with distribution network,
    - declaration on connection,
- generation facility operation:
    - operation management (part of grid usage contract),
    - property (and also authority) boundary between DSO and network user (producer),
    - access to the facility,
    - information exchange,
    - monitoring and remote control,
    - maintenance and regular testing responsibilities,
    - disconnection and reconnection of generation facility,
    - generation facility operator,
    - protection of generation facility.

The following must be registered (metered) within the network user generation facility (section 7.1 of the Rulebook):

- gross production of generators,
- generation facility auxiliary consumption,
- network user own consumption,
- electricity feed-in to the and imported (supplied) from distribution network.

In its response to the study questionnaire ERS indicated the following steps in the connection procedure:

- phase of obtaining permits for construction:
    - investor (producer) submits an application for connection approval,
    - DSO performs connection analyses,
    - DSO issues connection approval (providing all important technical data relevant for connection).
- connection construction phase:
    - investor (producer) submits requests for connection contract,
    - DSO drafts Connection Project,
    - DSO and investor sign Connection contract,
    - the distribution system operator performs connection construction,
    - independent company performs functional testing (when construction of power plant and connection are completed),
    - the DSO and investor sign grid usage contract before Power Plant permanent connection,
    - the producer applies for permanent connection.


1. ISSUANCE BUILDING PERMIT
PRODUCER
Claim for issuance of the grid connection authorisation for new generation facility; required documentation:
generation facility (producer) data
map of project location
location requirements on generation facility
copy of generation facility conceptual design
copy of concession contract
Request for grid connection authorisation is incomplete - DSO demanding additional data
DSO performs/develops
grid connection study (for DGs over 250 kW)
project of necessary reinforcements and modifications in the existing distrbution network
grid connection authorisation
2. CONSTRUCTION OF CONNECTION
PRODUCER
Claim for development of main design of connection and to coclude a conncetion contract; required documentation:
generation facilit main (detailed) design
proof of payment for the development of main design of connection
DSO
develops main design of interconnection of generation facility to distribution network and submits it for the audit
INDEPENDENT AUTHORISED PERSON
fixed by mutual agreement between DSO and Producer; makes aduit of the main design of interconnection
PRODUCER and DSO
sign connection contract
CONNECTION CONTRUCTION
PRODUCER concludes:
supply contract
power purchase agrement for feed-in during testiong operation
grid usage contract
SUPPLIER
DSO
DSO

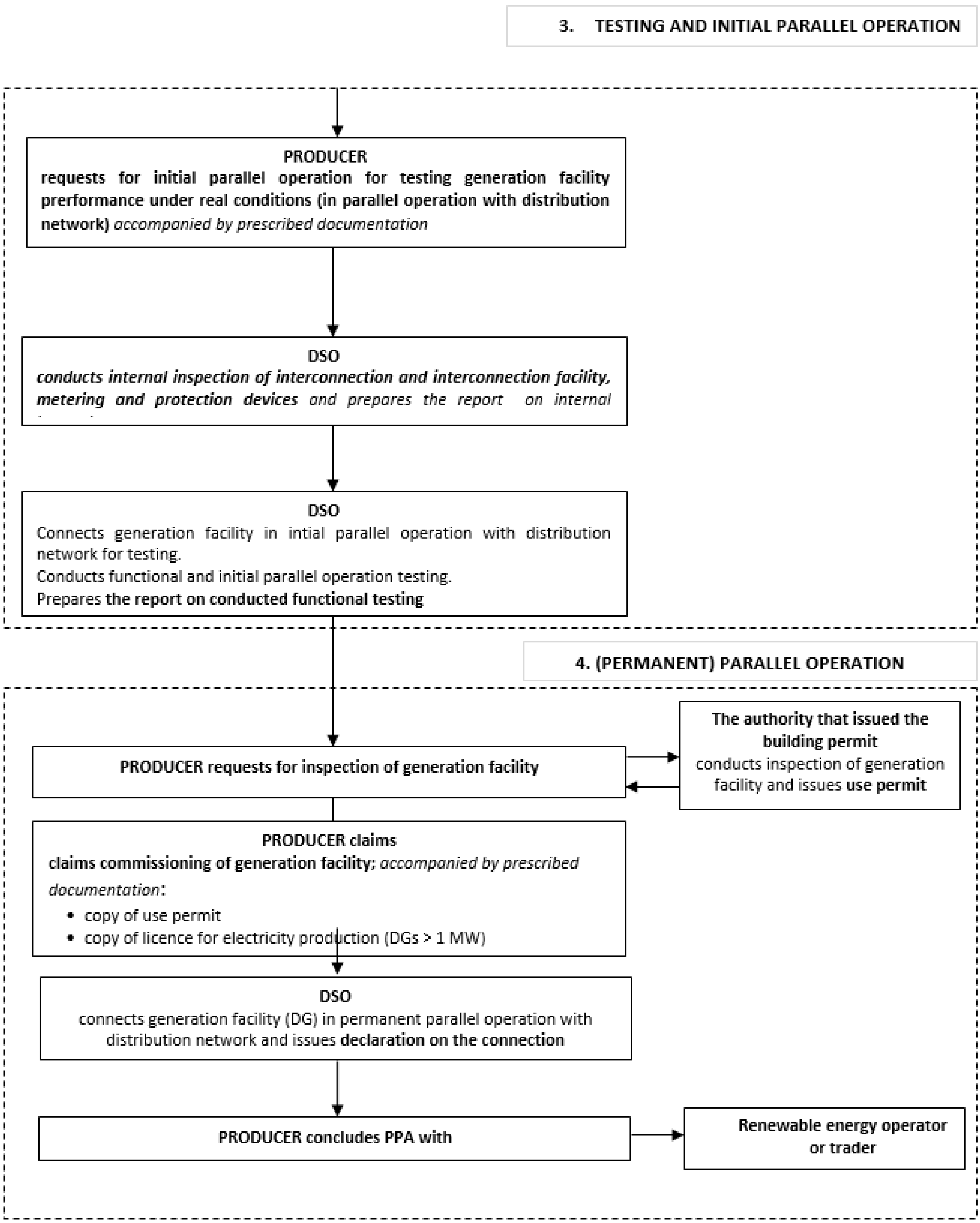


Figure 5.22 Flowchart of interconnection process; source the Rulebook (adopted in March 2014)

Producer bears real costs of (so called) non-standard connection to the distribution network till the point of common coupling and real costs of required modifications (reinforcements) in the existing network pursuant to provisions of the *Rulebook on methodology for setting the cost of connection to the distribution network*

(December 2008) and the *Rulebook defining the method, terms and conditions and procedure for connection to the distribution network of generation facilities which use renewable energy sources and efficient co-generation (Annex 3 - criteria for allocation of costs of technical reinforcement and improvement in the network between producers).*

Originating from rationale behind cost sharing model among customers from Article 40 of General terms and conditions for electricity supply (2008), the Rulebook from 2014 in its Annex 3 additionally prescribes cost sharing model among producers for:

- connection line,
- feeder bay and
- increase of existing distribution network hosting capacity.

Apportionment of costs to develop a new connection line shared among multiple producers is based on installed capacity of the production facilities (S_i) and the length of the connection which is used by each producer (l_i).

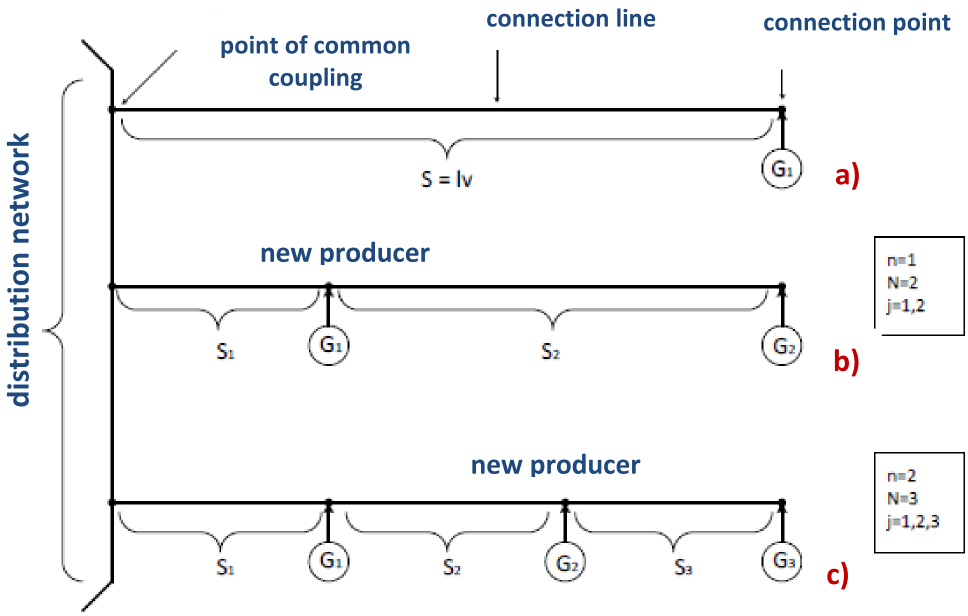


Figure 5.23 Principle of new connection line sharing between producers in ERS

In order to determine monetary compensation of ''N-1'' previous producers, section of connection line used by the N^{th} producer of length "l_n", is divided into segments whose number (s) is determined based on the number of producers (p) connected ahead of point of connection of the new N^{th} producer: s=p+1.

New producer that interconnects to the existing distribution line bears part of the total costs of the line according to the following cost sharing formula:

$$T_N = \sum_{j=1}^{s} T_j = \sum_{j=1}^{s} \left[T_{gj} + T_{ej} \right] = \sum_{j=1}^{s} \left[\frac{C_1}{(N+1)-j} \cdot \frac{l_j}{l_{voda}} + C_2 \cdot \frac{l_j}{l_{voda}} \cdot \frac{S_N}{\sum_{i=j}^{N} S_i} \right]$$

where: T_j is monetary compensation for j^{th} section of connection line which (N^{th}) new producer refunds to previously connected producers which have paid construction of the line; T_{gj} is the component of monetary compensation which is not dependent on the rated capacity of the line ; T_{ej} is the component of monetary compensation which is dependent on the rated capacity of the line; C_1 first costs component related to overall building setup of connection line not dependent on the rated capacity of the line; C_2 second costs component of connection line dependent on rated capacity of the line; N is total number of producers that are interconnected to the line; j is the ordinal number of line segment; l_j length of j^th^ line segment; l_n is length of connection line used by new producer (N), $l_n = \sum_{j=1}^{s} l_j$; l_{voda} is total length of connection line; S_N is apparent power of new producer; S_i is apparent power of i^th^ producer.

Monetary compensation from new to i^th^ producer is:

$$O_i = \sum_{j=1}^{s} O_{ij} = \sum_{j=1}^{s} \left[\frac{T_{gj}}{N-j} + T_{ej} \cdot \frac{S_i}{\sum_{\substack{k=j \\ k \neq n}}^{N} S_k} \right];\ i = 1,\ldots N;\ \ i \neq n$$

Costs of feeder bay shared among several producers is linearly distributed on producers:

$$C_n = \frac{C_u}{N}$$

where C_n is the part of feeder bay costs covered by n^th^ producer and C_u are total feeder bay costs.

Monetary compensation from new (N^th^) to each other producer is:

$$C_{ob} = \frac{C_n}{N-1}$$

Expenditure for increasing existing distribution network hosting capacity is distributed among producers based on producer share in total installed capacity of all producers

$$M_n = M_u \cdot \frac{S_N}{\sum_{i=1}^{N} S_i}$$

where: M_n is n_{th} producer share in total costs; M_u is total costs related to increasing existing distribution network hosting capacity.

Monetary compensation from new (N^th^) to i^th^ producer is:

$$M_{obi} = M_n \cdot \frac{S_i}{\sum_{\substack{k=1 \\ k \neq n}}^{N} S_k};\ i = 1,\ldots N;\ \ i \neq n$$

DSO is obliged by the Rulebook (2014) to assure proper implementation of previously described cost sharing model.

In comparison to the rest of the observed DSOs in the region, ERS web site (http://www.ers.ba/index.php?option=com_content&view=article&id=122%3Apodsticaj-proizvodnje-iz-

obnovljivih-izvora&catid=17%3Anovosti&Itemid=66&lang=ba) contains rather comprehensive publically available practical guidelines on the connection procedure and standard contracts (connection contract, PPA contract during test operation (i.e. initial parallel operation), grid usage contract).

Federation of Bosnia and Herzegovina

On the EPHZHB web site there are very limited information on the connection procedure and access to the grid; only in the section related to the standard forms for services provided by DSO (http://www.ephzhb.ba/kupci/dokumenti/). The same applies to the EPBiH (http://www.elektroprivreda.ba/stranica/dokumenti).

The REL (adopted in August 2013) envisages RES to enjoy priority in processing request for connection to the distribution network in the Federation of Bosnia and Herzegovina (Article 20). This "priority" principle, according to the REL, should be further elaborated in by-laws dealing with connection to distribution network. It could be noted that the Rulebook on methodology for setting the cost, terms and conditions of connection to the distribution network (adopted in October 2014) did not develop "priority" principle for RES.

In its answer to the questionnaire questions, EPHZHB indicated the following formal steps in DG connection procedure (in brackets are listed steps not involving DSO):

- DG owner shall complete written claim to DSO for issuance of the grid connection authorisation,
- DG connection assessment - for DGs over 250 kW DSO develops grid connection study,
- issuance of provisional (preliminary) grid connection authorisation by DSO,
- (issuance of preliminary decision on acquiring status of qualified producer by renewable energy operator),
- (issuance of building permit),
- issuance of grid connection authorisation by DSO,
- (issuance of licence for electricity production by regulatory authority),
- connection contract between DSO and DG owner,
- grid usage contract between DSO and DG owner,
- (electricity supply contract between supplier and DG owner),
- test operation - initial parallel operation with distribution network,
- commissioning of DG.

Simplified (shortened) procedure for interconnection of micro generation from RES

According to the Article 6 of the Rulebook on Rulebook on micro generation RES facilities (June 2014) the following are steps required in the interconnection procedure of micro generation to the grid:

- before commencing work on micro generation facility, owner shall complete claim to DSO for issuance of the grid connection authorisation,
- after the construction of the facility, owner shall complete claim to DSO for fitting the metering point,
- DSO shall perform fitting of the metering point for the micro generation facility.

5.8.7 DSOs overview

Table 5.13 gives an overview of the situation in the observed SEE region with regard of connection charging (who bears the cost of connection, classification of connection charging methodology, unit costs) and also number of contracts signed between DSO and DG investor in the connection procedure. It could be observed that in most of DSOs "deep" connection charging is applied. Only in Kosovo Distribution Charging Principles approved by ERO (regulatory authority) mandate “shallow” approach, however, Connection Charging Methodology is in the drafting process.

Table 5.13 Connection charging in SEE DSOs

DSO	Costs for connection			Contracts
	Who pays	Classification	Unit costs	
EDB	Investor *RES <10MW are exempt from paying 1) & 2) cost components (these are borne by DSO*): *1) grid connection study* *2) study of required investment and technical documentation for establishing of technical conditions in the network*	Deep	No *(investor pays specifically for the costs incurred for the particular connection)*	2
EPBIH	Investor/DSO (network usage fee) *micro-RES 2-23kW pay only for equipping metering point with metering equipment*	Other (deep)	Yes (MV 71,6 €/kW; LV 99,7 €/kW), but if actual connection costs exceed double the value of connection fee (i.e. unit costs multiplied by rated power capacity), then investor pays actual connection costs.	2 to 4
EPHZHB	Investor/DSO (network usage fee) *micro-RES 2-23kW pay only for equipping metering point with metering equipment*	Other (deep)	Yes (MV 70 €/kW; LV 100 €/kW), but if actual connection costs exceed double the value of connection fee (i.e. unit costs multiplied by rated power capacity), then investor pays actual connection costs.	2
EPS	Investor	Other (according to the methodology "shallow")	No (case-by-case)	2
ERS	Investor	Deep	No *(investor pays specifically for the costs incurred for the particular connection)*	2

DSO	Costs for connection			Contracts
	Who pays	Classification	Unit costs	
EVNM	Investor/DSO (network usage fee) Connection fee does not take into account needed reinforcements, but if there is a need to reinforce network then it pays for capacity	Shallow Deep	No (case-by-case)	1
HEP	Investor	Deep	No *(investor pays specifically for the costs incurred for the particular connection)*	LV 2 MV 5
KEDS	Investor	Shallow**	No ** (DSO shall develop connection charging methodology)	1
OSHEE	Investor	Deep (according to 2012 ERE nr. 22 regulation of new connections)	No (case-by-case; individually calculated)	1

KEDS** - *System operators shall develop connection charging methodologies in accordance with Tariff methodologies approved by ERO. Connection Charging Methodology is in the drafting process. Distribution Charging Principles, issued by ERO in 2012 stipulate: Distribution applicants for the connection of new generation, or increases in the connection capacity for existing generation, should pay shallow connection charges set so as to recover the direct costs of the provision of the connection to the nearest suitable point on the distribution system, including any metering and step-up transformers necessary to enable the connection but should not include the cost of any reinforcement of the system that may result from the connection upstream of the point of connection.*

5.9 Priority and guaranteed access; priority dispatching; curtailment

Apart from specifying priority grid access for RES, by RES Directive requirements are also imposed on TSOs and DSOs to support RES producers in their planning of projects (through information provision mainly). Costs for grid reinforcement may be borne by TSOs/DSOs and transmission and distribution tariffs must be cost/benefit reflective and non-discriminatory to RES. Market related arrangements should not present any artificial barriers to RES energy and RES generating installations should have priority dispatch.

Old RES Directive 2001/77/EC did not require developing transmission and distribution grid infrastructure and measures to reduce curtailments from higher share of electricity from RES. By RES Directive 2009/28/EC member states may require costs of technical adaptations to the grid to accommodate increasing share of RES to be borne by transmission and distribution system operators (T/DSO).

T/DSO are now required to provide RES producers and the public with information on grid connection cost estimates, timetables for processing requests, and an indicative timetable for any proposed grid connection. The previous Directive only required estimates of costs for grid connection to be provided to RES producers.

> *Member States shall require TSO and DSO to set up and make public their standard rules relating to the bearing and sharing of costs of technical adaptations, such as grid connections and grid reinforcements, improved operation of the grid and rules on the non-discriminatory implementation of the grid codes, which are necessary in order to integrate new producers feeding electricity produced from renewable energy sources into the interconnected grid.*

RES Directive 2009/28/EC (Article 16) obliges DSOs to provide for either priority access or guaranteed access to the grid-system of electricity produced from RES. Assuming that the reliability and safety of the grid is maintained, countries in the region must ensure that DSOs guarantee the distribution of renewable electricity and provide for priority access or guaranteed access to the grid system.

Priority access to the grid provides an assurance given to connected generators of RES that they will be able to sell and transmit their electricity in accordance with connection rules at all times (whenever the source is available).

When renewable electricity is integrated into the spot market, guaranteed access ensures that all electricity sold and supported gets access to the grid, allowing the use of a maximum of renewable electricity form installations connected to the grid.

Furthermore, priority dispatching is a requirement for RES, and countries must ensure that appropriate grid and market related operational measures are taken in order to minimise the curtailment of renewable electricity.

5.9.1 Albania

The 2015 Power Sector Law provides for priority and guaranteed access of RES to the electricity networks and also priority dispatch of electricity produced form RES.

The Law on Renewable Energy (2013) provides for priority access of renewables to the network.

According to the Distribution code (2010) (II.7.3 – requirements for the generators directly connected to the distribution system), in order to ensure that security and quality of supply standards are maintained, DSO may:

- **refuse permission for connection** (disconnect) of the generating unit connected do distribution system,
- require **revision of the construction or technical parameters** of the generation unit,
- or impose certain **restrictions**.

DSO shall **provide** sufficient explanatory **information** to justify the required revisions.

5.9.2 Kosovo

The priority access and priority dispatching for RES are included in Energy Law (2010) and Electricity Law (2010).

Energy Law (2010) states that:

- when **dispatching** electricity generation, the transmission system operator, or the distribution system operator where appropriate, shall give **priority** to electricity generation from RES and co-generation, subject only to any limits specified for purposes of system security by the Grid Code and other rules and codes.

For the priority rights given to electricity from RES to be fully implemented in practice, however, a proper market design is necessary which will enable implementation of such principles. Currently, there is no full compliance with Article 16 of Directive 2009/28/EC.

A provision in the Law on Electricity allowing the system operators to levy a charge for providing producers with an estimate of the costs associated with the connection is not in compliance with Article 16 (5) of Directive 2009/28/EC, according to which this constitutes an obligation of the system operators.

According to the Distribution code (April 2015; version 2; article 3.6.3.3 - designing standards), in order to ensure that security and quality of supply standards are maintained, DSO may:

- require **revision of the construction or technical parameters** of the generation unit,
- or impose certain **restrictions**.

DSO shall **provide** sufficient explanatory **information** to justify the required revisions.

Energy Law (2010; article 29 - refusal of system access) states that:

- producers shall not have the right to access the system, if they do not meet the connection requirements, or if the access would lead to major disturbances in supply,
- TSO and DSO may temporarily disconnect (“refusal of system access”) a producer in its system if it determines that producer’s facilities or equipment would fail to meet the technical norms or other conditions prescribed in the technical codes; a producer shall be informed in writing of the reasons for any such refusal; the producer which has been disconnected shall have the right to appeal such decision to the ERO.

5.9.3 Macedonia

DSO is obliged to:

- connect generators and consumers to the distribution system, as well as
- to allow third party access for distribution system use, pursuant to the present law and the Distribution Grid Code, and based on the principles of objectivity, transparency and non-discrimination.

The Energy Law (2011; article 122(3)) states that the electricity transmission or distribution system operators shall provide priority access to electricity systems for the electricity generated from renewable sources, taking due consideration of limits stemming from the possibilities in the electricity system.

With regard of curtailment, the Energy Law (2011; article 122(3)) states that the relevant transmission or distribution system operator can deny the access to the relevant grid only in cases of relevant electricity transmission or distribution capacity shortage and shall be obliged to inform the access applicant in written thereby providing detailed and unambiguous explanation of the reasons for the access denial.

In accordance to the Distribution Grid Code, in the emergency operation mode of the distribution system, DSO may disconnect users from the system without previous announcement in order to prevent further expansion of the disruptions. The emergency operation mode is defined in the Distribution Grid Code.

In the case of the exceptional conditions in the distribution network, DSO can limit the production with explanation to the DG.

5.9.4 Croatia

The new Law on Renewable Energy (2015) by Article 28 obliges DSO to provide RES and efficient cogeneration connection and access of to the network. There are not explicit obligations of "priority" access. Priority access and dispatching of RES and efficient cogeneration is stipulated by Article 19 of new Law on Renewable Energy.

Also the Electricity Law (2015) by Article 39 obliges DSO to "priority" access to all eligible producers connected to the distribution network, provided that the requirements relating to reliability and safety of the operation are fulfilled in particular pursuant to the Distribution Code. An eligible producer is an energy entity producing both electrical and thermal energy in a single production facility, using waste or renewable energy sources in an economically appropriate manner harmonized with environmental protection.

In the Grid (Distribution) Code (March 2006) and General Conditions for grid Usage and Electricity Supply (2015), there are no explicit provisions providing for RES priority dispatching. It could be observed that in terms of dispatching all producers are treated equally under the by-laws.

The obligations and responsibilities of the DSO regarding generation take-over and supply of electricity do not apply in case of force majeure, disturbances in network operation, emergency operation and other unexpected events in accordance with the General Conditions for grid Usage and Electricity Supply (2015).

Besides, the DSO may temporarily de-energize the grid users because of the scheduled works: inspection, testing or control metering, regular or extraordinary maintenance, overhaul, connection of new customers or producers and grid expansion or reconstruction.

DSO has the right to suspend delivery/take-over of electricity to the user:

- following the prior notice in accordance with Article 95 and 96 of the General Conditions for grid Usage and Electricity Supply (primarily related to non-payment, absence of PPA, breaching grid usage contract provisions, etc),
- without prior notice in accordance with Article 108 of the General Conditions for grid Usage and Electricity Supply.

DSO shall notify timely (as prescribed in Article 107) the customer or the producer of the scheduled duration of disruption in electricity supply for disruptions longer than three minutes.

According to Article 108 of the General Conditions for grid Usage and Electricity Supply (2015), in case of a disruption of supply resulting from failures and breakdowns in the grid or force majeure the DSO shall notify users and their suppliers through mass media and DSO web site of the estimated duration of the disruption in supply.

5.9.5 Bosnia and Herzegovina

Republic of Srpska

Law on Renewable Energy (2013) in its section 1.1. (Article 23) provides for priority access (dispatching) to RES or efficient co-generation. Only RES and efficient co-generation producers under feed-in tariff are entitled to priority access in accordance to submitted daily schedule of operation. All other RES and efficient co-generation producers, even those entitled to premium for electricity sold at the electricity market, are not entitled to priority access.

DSO is obliged to submit to each new generator using RES or efficient co-generation which requests for interconnection to the distribution network the following:

- a detailed analysis of possibilities and conditions for connection, technical solution of necessary reinforcements in the existing distribution network for the purposes of providing conditions for connection of the facility, as well as the estimate of costs of connecting of the generation facility to the distribution network,
- reasonable and precise timeframe for realization of the proposed method of connection.

Federation of Bosnia and Herzegovina

Article 20 of REL (2013) provides for priority access to all qualified producers (i.e. RES and co-generation) without restrictions on installed capacity.

There are no provisions regarding measures to minimize curtailment of electricity from renewable sources.

5.9.6 Serbia

Beside the right to sell the entire quantity of generated electricity to the state-owned purchaser under guaranteed preferential prices, all renewable generators (not only privileged under support measures) are given by explicit provisions of the law the right of priority access to the grid (Energy Law, Article 162) except in the case the security of the supply or operations of the distribution or transmission system are jeopardised. This is in line with Article 16 of Directive 2009/28/EC.

By Energy Law, if significant curtailment of RES, in order to guarantee the security of system and energy supply, occurred DSO shall report to regulator on those measures (curtailment), indicate which corrective measures they intend to take in order to prevent inappropriate curtailments.

It must be noticed, that even though in primary legislation principle provisions were introduced (in this sense Serbia has fully adopted 3rd Energy Package), implementation details shall be enforced by secondary legislation.

5.9.7 DSOs overview

Table 5.14 summarizes SEE DSOs practice with regard of priority connection, access and dispatching.

Table 5.14 SEE DSOs practice with regard of priority connection, access and dispatching

Country (DSO)	Priority access	Guaranteed access	Priority dispatch	Priority connection
Albania (OSHEE)	√ (PSL)	√(PSL)	√	REL (2013) obliges DSO to connect with priority all RES to the closest point in the grid ← *methodology for grid connection & standard connection agreement has not yet been adopted by ERE (due to the postponement of the entry into force of REL)*
BIH (EPBIH)	X	X	√	REL (2013) envisages all RES to enjoy priority in processing request for connection to the distribution network in the Federation of Bosnia and Herzegovina; Rulebook on methodology for setting the cost, terms and conditions of connection to the distribution network (2014) did not developthe "priority" principle for RES
BIH (EPHZHB)	√ (REL)	X	√ (REL 2013;but not in Distribution code 2008)	
BIH (ERS)	O (only incentivized RES)	X	O (only incentivized RES)	No (only principle of non-discrimination)
Croatia (HEP)	√ (REL)	√(REL)	√	No (only principle of non-discrimination)
Kosovo (KEDS)	√ (EL)	√(EL)	√	No (only principle of non-discrimination)
Macedonia (EVNM)	√(EL)	X	√	No (only principle of non-discrimination)
Serbia (EPS)	√ (EL)	√(EL)	√	No (only principle of non-discrimination)

PSL - Power Sector Law

EL - Electricity Law

REL - Renewable Energy Law

5.10 Denial of connection

The delicate issue with regard of interconnection to distribution network is the denial of connection. This study analysed how DSOs are dealing with new applications (connections) that introduce significant cost or technical issues in the network,

This issue refers to the impossibility to connect to the grid because the grid infrastructure is insufficient to allow connection of new plants. Quite often, this is not a permanent but a temporal problem. In these cases, the growth rate of DGs is higher than the grid infrastructure rate of development or reinforcement. As a consequence, deployment and integration of DGs is slowed down.

This issue is spread not only over SEE countries but also over the majority of the EU Member States (it has been reported in Belgium, Bulgaria, Estonia, Finland, France, Germany, Great Britain, Greece, Hungary, Ireland, Italy, Lithuania, Malta, the Netherlands, Poland, Romania and Spain). In countries where this issue has been reported the overall situation for grid connection was ranked as being negative and stakeholders described it as a serious problem that is causing also other barriers. Thus, lacking grid capacity has to be considered as a serious barrier.

The main causes for both permanent and temporal lack of grid capacities are complex or inefficient procedures. Moreover, insufficient planning is another factor when the development of the grid cannot keep pace with DG development. An insufficient adjustment of the grid planning process to the growth of DGs is also a strong indicator that the legal framework has not been sufficiently adapted to the transition of the energy system.

An improvement on the procedure of data collection and exchange of information, especially as regards expected deployment of DG installations might help to further mitigate the discussed issues. It might be considered to implement such databases or to increase the links between existing ones that already provide such information.

For example in Kosovo, based on Distribution Charging Principles issued by ERO in 2012 (in Article 11), the Connection Charging Methodology should include the criteria on which any decision by the DSO to refuse access (connection) to the system shall be made, which criteria shall be objective and technically and economically justified.

The Rule on General Condition in Energy Supply (2011) lay down:

- the system operator may **refuse to connect** an applicant temporarily or permanently only if such connection is technically or economically non-feasible according to the provisions of the grid or distribution code or other applicable codes,
- in such case a written statement identifying the reasons of refusal has to be issued and delivered to the applicant within a time period not exceeding thirty (30) calendar days from the date of delivery of the application,
- in its statement the system operator shall make reference to the possibility of a future connection according to the network development plan, if applicable.

6 SUPPORT SCHEMES (INCENTIVES) AND MARKET MODELS

6.1 State of play with regard of National renewable energy action plans

The Renewable Energy Directive [7] establishes an overall policy for the production and promotion of energy from RES in the EU. It requires the EU to fulfil at least 20 % of its total energy needs with renewables by 2020 – to be achieved through the attainment of individual national targets. The Member States are given an "indicative trajectory" to follow in the run-up to 2020. In terms of electricity consumption, renewables should provide about 35 % of the EU's power by 2020.

The Directive specifies national renewable energy targets for each country, taking into account its starting point and overall potential for renewables. These targets range from a low of 10 % in Malta to a high of 49 % in Sweden. In EU countries set out how they plan to meet these targets and the general course of their renewable energy policy in national renewable energy action plans (NREAP), including elements such as sectoral targets for shares of renewable energy for transport, electricity and heating/cooling, and how they will tackle administrative and grid barriers. The NREAPs will have to follow a binding template; if the Commission consider an NREAP to be inadequate it will consider initiating infringement proceedings against particular Member State. Progress towards national targets is measured every two years when EU countries publish national renewable energy progress reports. If they fall significantly sort of their interim trajectory over any two-year period, Member State will have to submit an amended NREAP stating how they will make up for the shortfall.

Croatia, the only EU country in the region, has national target of 20 % share of renewable energy in gross final energy consumption by 2020. At individual country level, seven EU member states have already reached their 2020 targets – Bulgaria, the Czech Republic, Estonia, Italy, Lithuania, Romania and Sweden, while Croatia is one of the countries that have already achieved more than 90 % of their target.

Under the definitions of the RES Directive, compared with most EU Member States countries in the observed region already have a relatively high proportion of energy from renewable sources. However, the active promotion of renewable energy sources has only recently become an issue of concern. Whilst some form of action has now been commenced the policy, legal, regulatory and institutional frameworks in the region are at an early stage. Progress in developing renewable energy frameworks varies between countries. Croatia for example is relatively well advanced, largely driven by its EU accession.

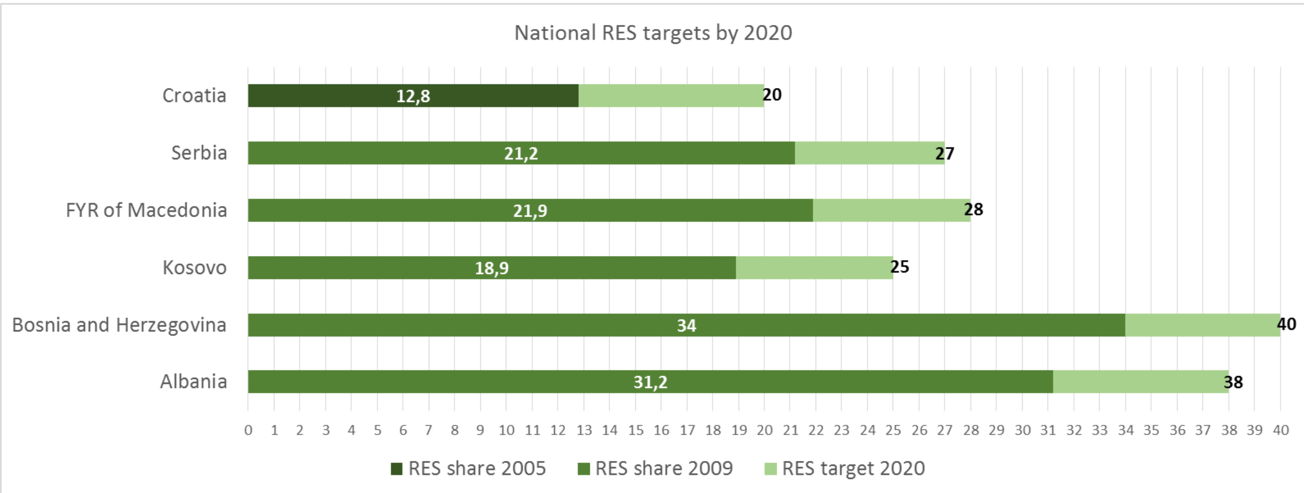


Figure 6.1 2020 RES targets in the observed countries (source: EU and Energy Community)

By Decision 2012/03/MC-EnC, the Energy Community Ministerial Council adopted Directive 2009/28/EC and determined the Contracting Parties' binding national targets to be achieved through the use of renewable energy in the electricity, heating and cooling, and transport sectors by 2020. For determining the targets, a similar methodology as for the EU Member States was applied (*Figure 6.1*).

Croatia (in 2013), Serbia (in 2013) and Kosovo (in 2013) adopted the National Renewable Energy Action Plan (NREAP), and the two entities in BiH adopted Renewable Energy Action Plan (REAP) in 2014.

Macedonia, Albania and BiH will have to finalise and adopt the National Renewable Energy Action Plan (NREAP) as soon as possible. Furthermore, in all the Contracting Parties a review of the existing legal and regulatory framework is needed to properly transpose Directive 2009/28/EC.

The new mandatory renewable energy targets are, in most cases, more ambitious than the existing targets set by each country, and will represent a significant increase in the proportion of renewable energy in the energy mix. Achieving these mandatory targets could require a radical policy rethink about how the required volumes of new RES energy will be sourced – whether from domestic resources or through joint projects and initiatives.

Some of the Contracting Parties still need to adopt proper support schemes for all forms of energy produced from renewable sources – i.e. electricity, heat and energy used for transport – to facilitate investments in renewable energy and be on track to meet the 2020 targets. None of the Contracting Parties have registered adequate progress in newly installed capacities in the last few years. The indicative trajectories are at risk of not being met.

Progress is also urgently required in the areas of transparency, consistency of rules and grid connection issues. Furthermore the authorisation and permitting processes have to be coordinated and streamlined.

6.2 Support schemes and measures

6.2.1 Albania

The government has developed two main tools to support development of RES:

- concessions for large HPPs,
- feed-in tariffs and purchase agreements for small HPPs. Small HPPs with installed capacity less than 15 MW can sign a long term purchase agreements with the Public Supplier for up to 15 years at a guaranteed feed-in tariff. The tariff is regulated and approved annually by regulatory authority (ERE). It is based on the import price of previous year and is adjusted year by year with inflation index (as indicated in [10] it equals 52,6 €/MWh). Feed-in tariffs for non-hydro RES have not yet been developed.

Up until recently the government regulated energy selling price for HPPs smaller than 15 MW installed capacity based on a methodology which was included in the now suspended Law on Renewable Energy. The feed-in tariff changed every year reflecting the average import price of the previous year and the average retail tariff for tariff customers. Therefore, the formula of the selling price was not a long term decision.

In February 2015, a Government Decree on the Methodology for the Fixed Tariff for Electricity Purchased by Small Hydropower Producers for 2015 was adopted. The Decree changed the base for calculation of the support (from the average import electricity price of the previous year adjusted with an inflation index) to the electricity price on the Hungarian Power Exchange (HUPX). Investors have complained against the new Methodology as the support price for the electricity produced by HPP up to 15 MW has decreased.

There is also customs duty exemption for machinery and equipment for RES electricity plants, and small HPPs are not obliged to pay water and land state property fees. Biofuels and machinery for biofuel production are also exempt from VAT, custom and excise taxes.

6.2.2 Kosovo

On the basis of primary legislation feed-in tariffs were selected as the main support measure for renewable energy. In November 2014, regulatory authority (ERO) approved the Rule on support scheme which defines the criteria and procedure for application and admission to the support scheme in order to support the generation of electricity from RES.

In December 2014 ERO issued Decision determining feed-in tariffs for generation of electricity from RES. Feed-in tariffs apply for generating capacities with new equipment (zero operation), whereas for solar/photovoltaic panels, the equipment must be recyclable. By this Decision :

- limits of capacities for admission to the support scheme, and
- feed-in tariffs applicable for the electricity generated from RES and admitted in the support scheme are defined.

There is a cap on total installed capacity of each technology that will receive feed-in tariffs. Currently the limits are as given in the following table:

Kosovo limits of capacities for admission to the Support Scheme	
Primary RES	Capacity [MW]
Photovoltaic energy	3
Solid biomass	14
Wind	35
Small HPP ≤10 MW	10

RES off-take agreements (hydro energy, wind energy and solid biomass) have a duration of 10 years, whereas the electricity generated from solar/photovoltaic energy will have a duration of 12 years, with applicable prices (feed-in tariffs) and admitted to the support scheme. Feed-in tariffs under this decision (will be adjusted annually for the inflation, after the first year of operation. The exact date on the manner of application of inflation shall be set out in the power purchase agreement.

6.2.3 Macedonia

In terms of support schemes, the Government adopted feed-in tariffs for electricity sold by preferential producers (produced from wind, small hydro, biomass/biogas and photovoltaic installations). Feed-in tariffs for electricity generated from geothermal energy are envisaged.

Power purchase agreements (PPA) are offered for 20 years for hydro and wind, and 15 years for solar PV, biomass and biogas. The contracts are based on a template which has been approved by the Energy Regulatory Commission (ERC).

There is a cap on total installed capacity of each technology that will receive feed-in tariffs. Currently the limits are as given in the following table:

Macedonian limits of capacities for admission to the Support Scheme	
Primary RES	Capacity [MW]
Photovoltaic energy	18 (4 on installations up to 50 kW; 14 on installations between 50 kW and 1 MW)
Solid biomass	10
Biogas	7
Wind	50 (2015); 65 (2016); 100 (2020); 150 (2025)
Small HPP ≤ 10 MW	no

Besides feed-in tariffs (main support scheme), in accordance with the Government promotion of the RES, several banks in the country support projects in the area of RES through several credit lines. This credit lines offer to the customers the option to invest in new, innovative projects through the use of renewable energy sources, improving energy efficiency and saving energy.

6.2.4 Croatia

In order to incentivize production of green electricity, in 2007 Croatia introduced the feed-in tariff (FIT) system for the first time. The basic principle for incentivizing renewable energy is that a producer of renewable energy may obtain so called "preferential status" and thus become eligible to receive the FIT. The FIT in general depends on the type of facility and its output and consists of a fixed part determined by the tariff system; and a variable part which depends on the local content requirement.

Electricity generated by incentivized eligible producers is sold to the market operator via a mandatory off-take. The FIT system applies for a period of 14 years. Incentives are not available for electricity generated but not fed into the grid (self-consumed).

The new Law on renewable energy sources and high-efficient cogeneration was adopted by the Croatian government in October 2015. It will lead to important regulatory changes related to incentivising and market model for RES. In theory, its purpose is to unify and harmonize regulations in the RES sector in order to boost the production and use of renewable energy in the country as well as to fully align domestic rules to EU law, among other goals, while offering more security to RES investors.

It introduced several substantial changes:

- competitive procedures (tender or auction) to allocate financial support to different renewables technologies,
- market premiums and feed-in tariffs only for RES ≤ 30 kW,
- RES-balance group (whose members are all RES producers under feed-in tariffs).

Projects for which an off-take agreement was executed prior to the adoption of the new Law on renewable energy sources and high-efficient cogeneration, have the FIT calculated according to the "old" tariff systems (i.e. tariff systems from 2007, 2012 and 2013).

In September 2015, new caps on total installed capacity of each technology (i.e. eligible producers) that will receive support based on the outcome of the competitive procedure (i.e. feed-in tariffs for RES ≤ 30 kW or market premium) were introduced. Current limits are as given in the following table:

Croatian limits of capacities for admission to the Support Scheme	
Primary RES	Capacity [MW]
Photovoltaic energy	12*
Solid biomass	120
Biogas	70
Wind	744
Small HPP ≤ 10 MW	35
Geothermal	30
* According to the legislation in the field of RES and cogeneration, market operator (HROTE) will sign off-take agreements at feed-in tariffs with investors until the maximum power output in PV plants reaches 5 MW for integrated plants, 5 MW for non-integrated plants and 2 MW for plants owned by the state and local institutions. The quotas for PV plants were filled on January 1, 2014.	

Still a number of key bylaws need to be adopted in order for the new framework to be fully effective. Following from the Energy Act and the Electricity Market Act, it is necessary to draft new subordinate legislation that will improve market functioning and the calculation of balancing costs caused by eligible producers and accordingly imbalance charges for eligible producers in the incentives system.

Besides incentivizing renewable energy through feed-in tariffs, there is currently a program of the Croatian Bank for Reconstruction and Development (HBOR) for the financing of RES projects either directly or, which happens more often, through banks which have cooperation with HBOR. The financing term is up to 14 years.

6.2.5 Serbia

As regards the promotion of energy from renewable sources, Serbia applies a feed-in tariff model since 2009. The initial scheme underwent notable improvements with the adoption of the 2011 Energy Law, the accompanying bylaws which were adopted in early 2013 and model power purchase agreements (PPA) in the summer of 2013.

Generators of energy from renewable sources are considered privileged producers. This applies to HPP below 30 MW, wind, solid biomass, geothermal, biogas, waste and landfill and sewage gas and solar PV (building integrated PVs up to 500 kW). According to the NREAP, Serbia plans to develop only 500 MW in wind until 2020 and introduces an intermediate cap of 300 MW until the end of 2015. For solar PV, there is an overall cap of 10 MW until 2020. There is a cap on total installed capacity of each technology that will receive feed-in tariffs. Currently the limits are as given in the following table:

Serbian limits of capacities for admission to the Support Scheme up until 2020	
Primary RES	Capacity [MW]
Photovoltaic energy (building integrated up to 500 kW)	10*
Solid biomass	no
Biogas	no
Wind	(350 until end of 2015) 500
Small HPP ≤ 30 MW	no
Geothermal	no
*2 MW is the limit for roof-mounted power plants using solar radiation energy of individual capacity up to 30 kW, 2 MW for roof-mounted power plants using solar radiation energy in the facilities of individual capacity from 30 kW to 500 kW and 6 MW in the ground-mounted power plants using solar radiation energy	

Privileged producers are entitled to a feed-in tariff for a period of 12 years.

The quotas for SPP are currently filled. The decision of the Ministry of mining and energy for new solar quotas is under preparation.

Feed-in premiums are not defined in the existing legislation. Conditions for obtaining premiums have not been set.

6.2.6 Bosnia and Herzegovina

District of Brcko

No support scheme adopted yet.

Republic of Srpska

In Republic of Srpska, in May 2013 the Renewable Energy Law has been adopted and then in May 2014, the Renewable Energy Action Plan (REAP) of Republic of Srpska entity.

Types of incentives for generation of electricity from RES or in efficient co-generation are as follows:

a) benefits while interconnecting to the network,
b) priority access to the network (priority dispatching),
c) guaranteed purchase of produced electricity,
d) right to the feed-in tariff,
e) right to the premium for self-consumption or sale on the market.

In other words, incentives can take the form of feed-in tariffs or premiums offered on top of an administratively set reference electricity price.

Eligible for guaranteed feed- in tariffs or premiums are the following types of generation facilities:

a) hydro power plants (HPP) up to including 10 MW,
b) wind power plants (WPP) up to including 10 MW,
c) solid biomass power plants up to including 10 MW,
d) biogas power plants up to including 1 MW,
e) solar power plants (SPP):
    - building integrated up to including 1 MW,
    - on the land of up to including 250 kW,
f) geothermal facilities up to including 10 MW.

Besides previously listed generation facilities the following generation facilities:

a) wind power plants over 10 MW,
b) facilities in efficient co-generation, the capacity of more than 10 MW and less than 30 MW,

are eligible for the premium for electricity sold on the market or produced electricity for self-consumption (for own needs; i.e. directly consumed). "Consumption for own needs" means consumption of produced electricity in network user facility; this consumption does not included consumption of generation facilities.

Premium is a part of the guaranteed feed in tariff which compensates generator of electricity from RES and efficient cogeneration for the average unit costs of electricity production, specific for some technologies which exceed the amount covered by the reference price. Reference price means the wholesale price of electricity (it will be regulated in the transitional period till complete market opening or market price).

Support is granted for 15 years.

In May 2014, the Renewable Energy Action Plan (REAP) of Republic of Srpska entity introduced per year caps on the total installed capacity entitled to the feed-in tariffs and premium. *Table 6.1* summarizes limits (quotas) of capacities for admission to the feed-in tariffs and premium up until 2020.

Table 6.1 Republic of Srpska limits of capacities for admission to the Support Scheme up until 2020

Republic of Srpska limits of capacities for admission to the Support Scheme (feed-in tariff and premium) up until 2020	
Primary RES	Capacity [MW]
Photovoltaic energy	4,2
Solid biomass	10
Biogas	6,5
Wind	100
Small HPP ≤ 10 MW	112,36

The REL (2013) introduced even some additional (specific) incentive measures:

- guaranteed purchase during the generation facility test operation (i.e. initial parallel operation),
- "net-metering" for end-users with installed capacity is up to including 50 kW who generate their own electricity.

"Net metering" is defined as the difference (metered at two-direction meter) between consumed (imported) from the grid and electricity generated by end-user with installed capacity is up to including 50 kW. End user connected to the 0,4 kV voltage level, which produces electricity for own needs (so called direct/self-consumption) by its own generators using RES, can consume or deliver (feed-in) electricity from/to distribution network following the principle of "net metering" after having obtained the decision from the regulatory authority.

The RES or efficient co-generation in a new facility, connected to distribution network and eligible for feed-in tariff, is entitled to guaranteed purchase during the generation facility test operation at the price of electricity for covering distribution losses. This incentive is valid upon expiry of the testing period no later than 60 days after obtaining use permit.

Federation of Bosnia and Herzegovina

In Federation entity qualified producer is producer that generates electricity and heat in a single generation plant, uses waste or renewable energy resources for generation of electricity in an economically viable way in compliance with environmental protection. The status of qualified producer shall be acquired on the basis of a decision to be issued by the competent authority.

Privileged producer is qualified producer that based on the criteria stipulated by REL (2013) (i.e. yearly quotas for incentivizing, generation facility installed capacity, estimate time until commissioning), may claim an incentive price: guaranteed feed-in tariff. The feed-in tariff is paid for energy from small hydro (up until including 10 MW), wind, solid biomass and solar (up until including 1 MW).

All qualified producers that are not eligible for feed-in tariffs, and are within quotas defined by REAP, may claim PPA at a reference price from renewable energy operator. The same applies to privileged producers whose PPA at a guaranteed feed-in tariff terminated (and are within quotas defined by REAP).

All other producers, outside the support scheme, must sell their electricity on the market.

In the Federation of Bosnia and Herzegovina support (at guaranteed or reference price) is granted for 12 years.

During test operation, all RES producers are entitled to mandatory purchase from renewable energy operator at a reference price. Test operation must not take longer than 6 months.

Special support scheme is stipulated for micro generation RES facilities. These are, by definition, facilities using RES with installed capacity between 2 kW and 23 kW. Owners of micro generation RES facilities are natural or legal persons that are final customers of some electricity supplier from Federation entity. Installed capacity of micro generation facility cannot be greater that the contractually committed capacity (connection power) of final customer owning the facility. In other words, for interconnection of the micro generation facility to the distribution network, existing connection to the grid used by the owner of the facility (final customer) is used.

Simplified (shortened) procedures are envisaged for such producers, as prescribed by the Rulebook on micro generation RES facilities (June 2014) and in section 5.8.6 of this study. Micro generation facility must be located near or within the existing building which already has a meter (for accounting purposes). Existing metering point shall be fitted with additional dedicated meter for registering (metering) electricity production in micro generation facility. Electricity produced in micro generation facility is purchased by the renewable energy operator at a guaranteed feed-in tariff. Support (at guaranteed feed-in tariff) is granted for 12 years. After this period, micro generation RES facilities is eligible for a mandatory purchase at a reference price. Owners of micro generation facility pay only for equipping metering point with adequate metering equipment (they do not pay connection fee as other network users).

Based on [5], in line with Articles 20 and 26 of REL, the renewable energy operator drafted two model power purchase agreements for renewable energy investors (not publically available on the renewable energy operator web site):

- PPA at a guaranteed feed-in tariff,
- PPA at a reference price.

It could be observed from the Energy Community analysis that these agreements currently do not regulate the issue of balancing costs.

Table 6.2 Dynamic quota of incentivized RES production in 2015.

Dynamic quota 2015.	Estimated working hours per year	*MW*	*GWh*
Hydro PP	4100	*4,830*	*19,800*
small (‹ 1 MW)	4100	0,253	1,037
medium (between 1 and 10 MW)	4100	4,577	18,763
large (› 10 MW)		0,000	0,000
Solar PP	1500	*1,333*	*1,999*
PV		*1,333*	*1,999*
micro (between 0,002 and 0,023 MW)		0,400	0,600
mini (between 0,023 and 0,150 MW)		0,533	0,800
small (between 0,150 and 1 MW)		0,400	0,599
Concentrated		*0,000*	*0,000*
Wind PP	2500	*0,000*	*0,000*
land		0,000	0,000
Biomass PP	6500	*0,923*	*6,000*
solid		0,923	6,000
SUM		*7,086*	*27,799*

In May 2014, the Renewable Energy Action Plan (REAP) of Federation entity introduced per year caps on the total installed capacity entitled to the feed-in tariffs. *Table 6.2* gives dynamic quota of incentivized RES production in 2015. *Table 6.3* summarizes total limits (quotas) of capacities for admission to the feed-in tariffs up until 2020.

Table 6.3 Federation BiH limits of capacities for admission to the Support Scheme up until 2020

Federation BiH limits of capacities for admission to the Support Scheme up until 2020	
Primary RES	Capacity [MW]
Photovoltaic energy	12
Solid biomass	4,615
Biogas	no incentives envisaged by REAP
Wind	42,8
Small HPP ≤ 10 MW	50

6.2.7 Countries overview

In Serbia and Albania privileged producers are HPP below 30 MW and 15 MW respectively, while in all other countries small HPP below 10 MW.

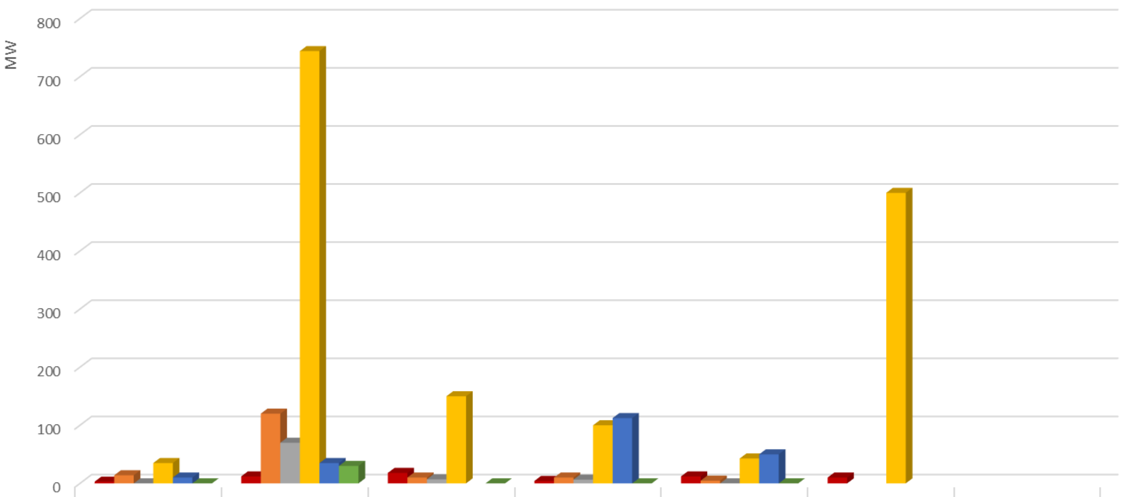
It could be observed that in BiH entities there is a per year technology cap on installed capacity that is entitled to the support measures. The same applies to Serbia and Macedonia, but for only for WPP. In Croatia and Kosovo there are only overall technology caps on installed capacity that is entitled to the support measures.

Besides quotas for incentivised RES, in BiH and Croatia there are limits for WPP interconnection due to operational security of the system. In BiH the capacity of WPPs is currently limited to 350 MW (230 MW applies to Federation entity), while in Croatia to 400 MW. However, in both countries the applications for connection of WPPs exceed the limit by far (*Table 6.4*).

Table 6.4 Limits for WPP interconnection due to operational security of the system

DSO	**Limit due to operational security of the system**
EDB	WPP (capped by NOS BiH; enforced by entity REAPs) 350 MW (BiH) 230 MW FBIH REAP *the applications for connection of WPP exceed the capacity by far*
EPBIH	
EPHZHB	
ERS	
EPS	
EVNM	
HEP	WPP (capped by HOPS) ~ 400 MW *the applications for connection of WPP exceed the capacity by far*
KEDS	
OSHEE	

Overall technology cap until 2020 as regards of promotion of RES



	Kosovo	Croatia	Macedonia	BiH (RS)	BiH (Federation)	Serbia	Albania
Photovoltaic energy	3	12	18	4,2	12	10	
Solid biomass	14	120	10	10	4,615		
Biogas	0	70	7	6,5	0		
Wind	35	744	150	100	42,8	500	
Small HPP ≤ 10 MW	10	35		112,36	50		
Geothermal	0	30	0	0	0		

"0" means that RES technology is not incentivized
" " means that there is no cap

Photovoltaic energy · Solid biomass · Biogas · Wind · Small HPP ≤ 10 MW · Geothermal

Figure 6.2 Overall technology cap as regards of promotion of RES – until 2020

6.3 Market model for RES and Independent Power Producers (IPPs)

6.3.1 Albania

An Electricity Market Model was developed in 2008 (approved by the decree no. 338, date 19.03.2008) to facilitate PPAs between small and independent power producers (SPPs/IPPs), and electricity suppliers. The model considers RES generators as SPPs or IPPs allowing their existence on the market and access to the grid.

Under Albanian Electricity Market Model SPPs are power generators that are connected to the distribution system. SPPs with a license for generation may sell electrical power to Qualified Suppliers, Traders or DSO at freely negotiated terms. SPPs may sell to the Wholesale Public Supplier with regulated price. ERE shall establish unified and simplified tariff calculation methodology for sales from SPPs under the regulated market. SPPs may sell electricity to system operator to cover their energy losses under contract approved by the ERE. A SPP may apply for Qualified Supplier license if he chooses to sell electricity directly to Eligible Customers.

Based on the questionnaire response for this study, from 2016 DSO might be obliged to purchase electricity produced by SPPs connected to distribution network.

Although, the Albanian Market Model provides for that for any SPPs connected to the distribution network despite their technology, the wholesale public supplier (state-owned generation company KESH) will have the obligation to purchase their output with a price approved by the ERE, no feed-in tariffs are approved for other technologies.

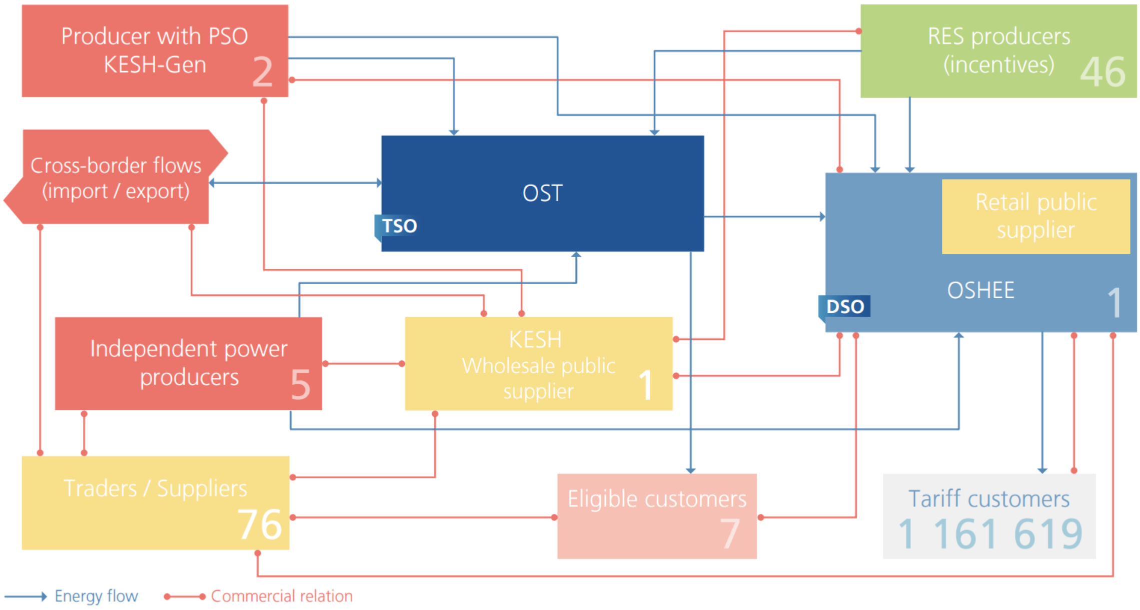


Figure 6.3 Albania electricity market model (source: Energy Community [8])

The role of renewable energy operator that had been previously assigned to the wholesale public supplier is now removed by the Power Sector Law adopted in 2015. The appointment of a renewable energy operator to manage the incentive system for new renewable energy producers has not been decided yet.

New market model is to be adopted before end-2015. A project for the establishment of a national organized day-ahead market and local power exchange has started in 2015 and is ongoing.

Privileged producers in Albania are being exempt from payment of costs for imbalances. The transmission system operator has started activities on implementing fully-fledged balancing market with imbalance settlement mechanism based on non-discriminatory balance responsibility. It still remains open whether SPPs and if so to what extent SPPs will be incorporated into the imbalance settlement mechanism.

6.3.2 Kosovo

In accordance to the Electricity Law (2010, Article 9):

- the public supplier (KEDS (KESCO)) shall give purchasing priority to electricity produced from RES for which a certificate of origin has been issued by the Energy Regulatory Office,
- public supplier shall be required to purchase at a regulated tariff the entire amount of electricity produced from RES, required to meet the needs of electricity consumption in Kosovo, with the exception of any amount for which the producer has entered into contracts pursuant to the Electricity Law.

Subject to obligation of producer (> 5 MW) to provide electricity to public supplier, a producer may enter into a contract to sell, at freely negotiated prices, the electricity produced by it, or the capacity of its power plants, to (*Figure 6.4*): eligible customers in Kosovo, suppliers in Kosovo, foreign eligible customers or external suppliers, for which purpose it may export electricity, and/or the public supplier, in cases where Article 7 of this Law does not apply.

Based on [11], discussions are conducted on whether RES generators will, after the termination of their PPAs, participate in the market or be granted the right to another PPA with public supplier under different conditions.

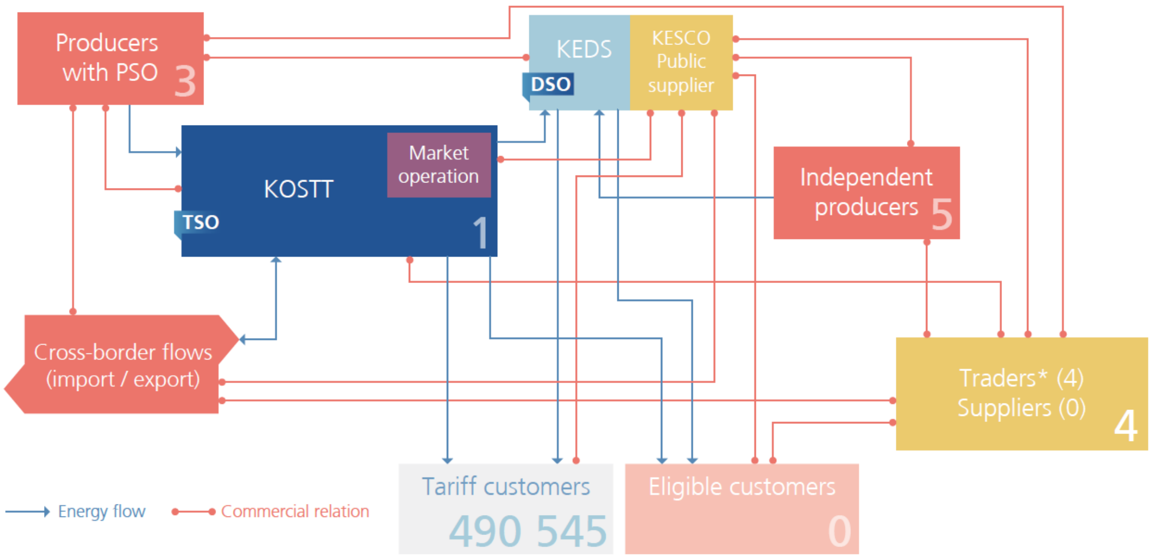


Figure 6.4 Kosovo electricity market model

According to Article 12 of the Rule on support scheme from December 2014, the Public Supplier, in consultation with the ERO, shall prepare the draft-models of the PPAs. These draft-models shall be approved by the ERO, upon a consultation with third parties. The ERO may instruct the Public Supplier in any moment before signing the PPA, in order for it to make the changes in the draft-models in question as it deems necessary. The approval of this sample agreement is expected to increase security for investors. According to the current scheme, PPAs are signed only after the construction of RES plants, at the time of their commissioning, which makes project funding difficult.

New Market Rules were published by KOSTT (TSO), upon approval of regulatory authority ERO, in December 2013, where balancing rules and the imbalance settlement mechanism are defined. All generating units are financially responsible for imbalances except the wind generators <10 MW. Producers of renewable electricity are required to pay only 25 % of their imbalance.

According to Grid Code for WPP, approved by ERO in December 2010, in order to support the KOSTT (TSO) in its duty to balance the system in real time, and to allow for the limited accuracy of wind speed forecasts made up to 30 hours ahead of real time, each generator shall provide the facility to revise, and if necessary, amend their physical nomination submission at any time up to 60 minutes before the hour of market operations in which the revised value is to apply. If the TSO accepts the revised submission (which it is not obliged to do), it will send an acknowledgement to the generator and notify the market operator. Namely, for system security, WPPs are obliged to forecast wind speed and submit it to the TSO up to 30 hours ahead of scheduling time and to provide the wind speed measurement to the TSO [4].

6.3.3 Macedonia

The market operator established within the transmission system operator (MEPSO) is obliged to buy all the electricity produced from preferential producers.

Preferential producers are not charged for their imbalance. A balancing group created by the market operator takes balance responsibility for all preferential producers. The electricity produced from the preferential producers is sold by the market operator to the electricity suppliers and traders. The average price at which this amount of energy is being sold includes cost for imbalances.

Preferential producers with capacities above 10 MW have to submit daily physical nominations to the market operator. According to [3], starting from 2015 large preferential producers are obliged to take balance responsibility.

Distributed generators, which have not obtained status of preferential producers, send hourly plans to the market operator also for the purpose of calculation of the imbalances (i.e. the deviation between scheduled and produced electricity).

If the DG operates as an independent power producer than, in accordance to the Energy Law, it can sell electricity to the traders, suppliers, DSO and TSO for covering the electricity losses in the distribution and transmission network, subsequently. The prices are negotiable.

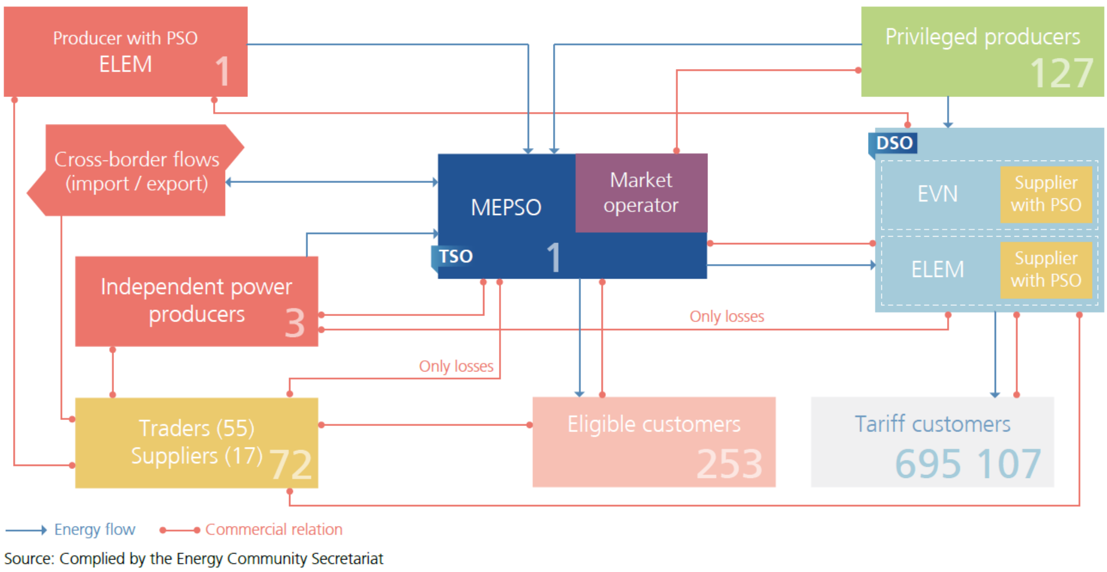


Figure 6.5 Macedonia electricity market model

6.3.4 Croatia

The market operator is obliged to buy all the electricity produced from:

- existing preferential producers under feed-in tariff that have already signed PPA with market operator (i.e. old FIT support scheme),
- new preferential producers ≤ 30 kW that subject to competitive process entered into PPA with market operator (i.e. new FIT support scheme).

The above mandatory off-take regime and mandatory off-take prices are not applicable to household-sized power plants with a connection capacity below 500 kVA. The electricity generated by such household-sized power plants must be off-taken by the electricity supplier servicing the given connection point and principally be set off against the electricity consumed by the household end-user. This scheme is available only for so called prosumers (network users) with a production capacity of up to 500 kW, and connection power as a consumer greater than the connection power as a producer. This model, still not developed in detail, could be regarded as net-metering.

Producers under market premium model shall sell electricity on the market in line with new market rules that are currently (October, 2015) in the process of preparation.

As the market rules and other by-laws are being drafted, it still remains open whether there will be a simplified off-take scheme for the sale of electricity generated by the plant and fed into the grid (e.g. presuming some intermediary between the producer and the market), available to DGs up to a certain threshold that are not eligible to incentives (feed-in or premium) and prosumers over 500 kW.

In the current preparation of new regulations regarding renewable energy and the electricity market, consideration is being given how to oblige eligible producers to reimburse their deviations from the submitted production plans to market operator (HROTE).

6.3.5 Serbia

EPS Supply (the Public Supplier) is under an obligation to purchase all renewable energy generated by privileged producers under power purchase agreements.

According to the Decree on Incentives for privileged energy producers (2013), after the expiration of the incentive period privileged producer has the right to conclude a contract with the Public Supplier for the purchase of electricity produced under market conditions.

The producer cannot feed-in electricity into the distribution system without a signed PPA for the purchase of electricity produced by power plants (including non-incentivised RES producers). In this sense, in accordance with the Energy Law (2014), independent producers which do not have a privileged status must sign PPA with some supplier.

Privileged producers are exempted from balancing responsibilities and costs during the entire 12 years. For other producers balance responsibility is stipulated by Energy Law.

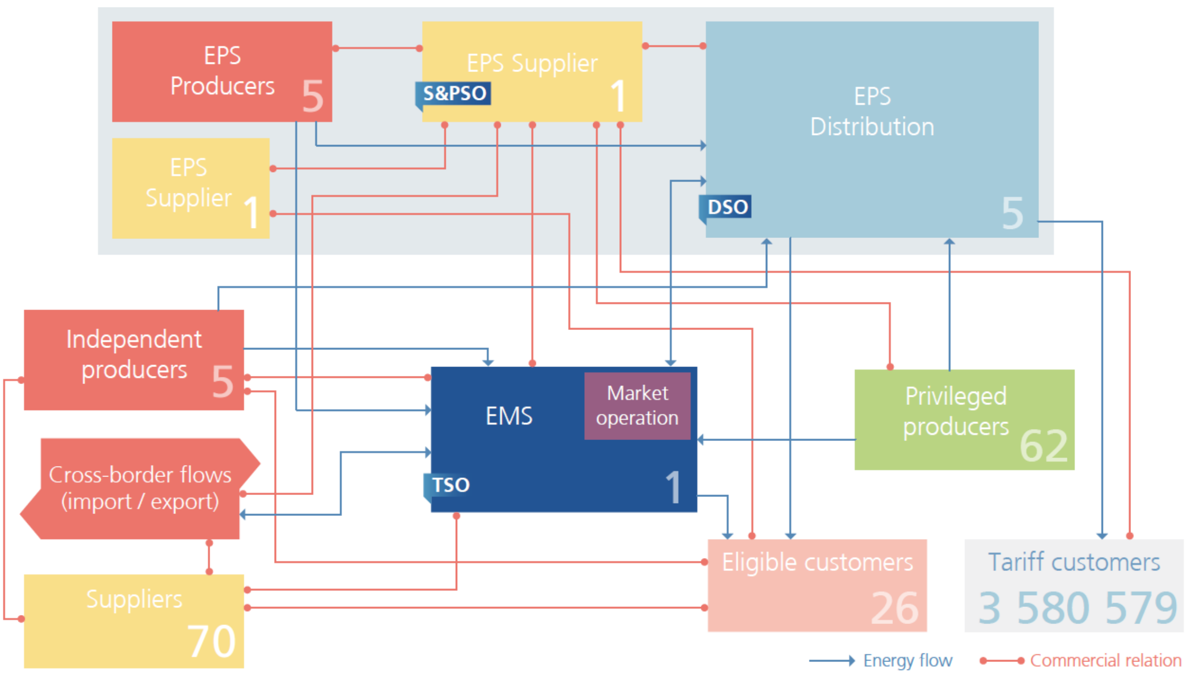


Figure 6.6 Serbian electricity market model (source Energy Community [8])

6.3.6 Bosnia and Herzegovina

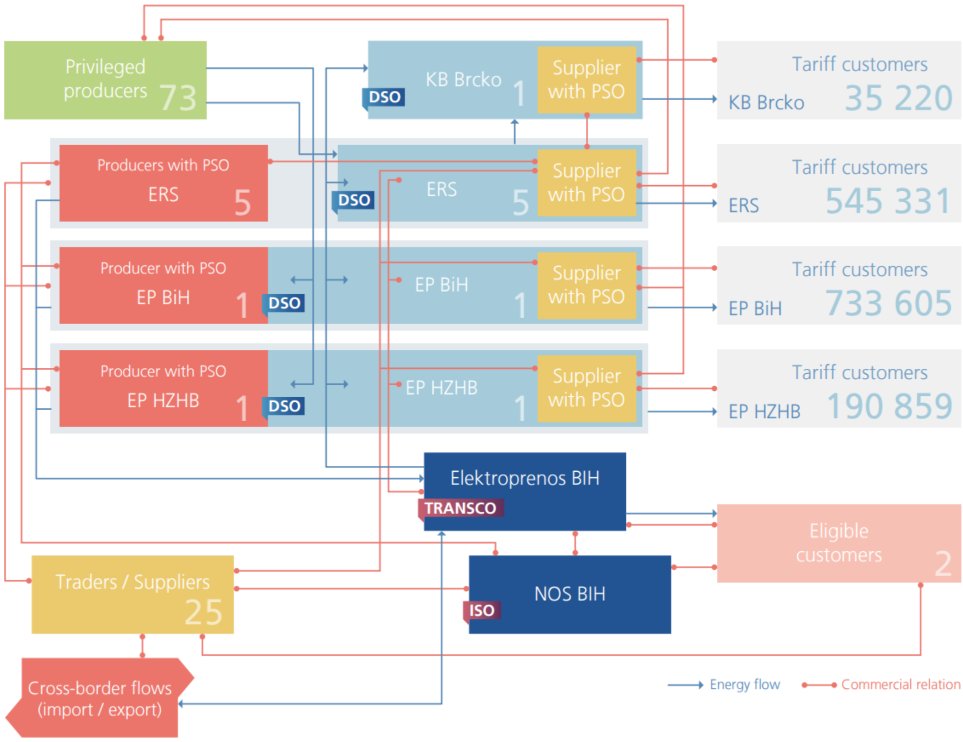


Figure 6.7 Bosnia and Herzegovina's electricity market model (source Energy [8])

Republic of Srpska

According to the *Rulebook defining the method, terms and conditions and procedure for connection to the distribution network of generation facilities which use renewable energy sources and efficient co-generation* (section 9.6) producer might conclude power purchase contract with:

- DSO related to the test operation (i.e. initial parallel operation) of generation facility,
- renewable energy operator (i.e. single buyer for incentivized RES electricity) or trader on electricity market related to the so called "permanent" parallel operation with distribution network.

Currently, a unit created within ERS functions as a single buyer for incentivized renewable electricity (i.e. renewable energy operator). The deadline for the establishment of a separate legal company fulfilling this function expired in December 2014.

Producers that opt for selling the electricity on the market to other suppliers receive feed-in premiums and have to take balance responsibility.

Financial settlement of imbalances shall start in 2016. According to REL (2013) Article 23, only power plants over 500 kW installed capacity shall be charged for imbalances:

- power plants under feed-in support scheme shall pay 25 % of imbalances (75 % is covered by the incentive fee for electricity production from RES and efficient cogeneration),
- all other power plants (including power plants entitled to premium support) shall pay 100 % of imbalances.

Financial settlement of imbalances of power plants under support scheme by-law is currently under preparation.

Federation of Bosnia and Herzegovina

In Federation of Bosnia and Herzegovina all incentivized renewable energy is bought by a newly established institution the “renewable energy operator”- as a single buyer. In this section *Figure 6.7* is given for consistency - for all countries electricity market model that is contained on the Internet web site of the Energy Community is given. It must be noted, however, that the figure does not contain “renewable energy operator” for the Federation of BiH, although it obtained a licence (from FERK regulatory authority) in September 2014.

By REL (August 2013) "renewable energy operator" is obliged to buy electricity produced by privileged RES producers whose production is incentivized (guaranteed feed-in tariff) and also to buy electricity produced by qualified RES producers whose production is not incentivized but are within quotas defined bay REAP (mandatory off-take at a reference price).

All suppliers are obliged to purchase a specified fraction of their electricity from “renewable energy operator” at 54,2 €/MWh.

Unlike all other producers, qualified producers <150 kW, as well as micro generation from RES, are not required to submit daily generation forecasts to the “renewable energy operator” (Article 20(3b) of REL) neither to take balance responsibility (pay for imbalances).

Renewable energy operator shall establish a methodology for allocating costs of balancing to the privileged and qualified producers and the also share of costs of balancing that will be covered by incentive fees collected from final customers.

The system operators are required to prescribe methodology for prediction of production and delivery of data to operators for producer >150 kW; producers over 3 MW shall predict day ahead hourly production, while other producers over 150 kW and below 3 MW only weekly production.

6.3.7 Countries overview

All countries in the observed region have implemented schemes for the promotion of energy from renewable sources in the form of operational aid, which in some cases were complemented by investment support offered to renewable energy producers. Initially, support schemes based on feed-in tariffs were introduced as most suitable for ensuring investor confidence and initiating deployment of renewable energy potential.

Table 6.5 contains overview of current support scheme in each DSO in SEE as well as renewable energy operator managing the support scheme.

Figure 6.8 depicts period of granting fee-in tariffs. In some countries it depends on the RES technology (Macedonia, Kosovo). It ranges from 10 to 20 years. It could be observed that feed-in premiums have only been introduced in Republic of Srpska and Croatia (since October 2015). The same applies to net-metering.

Only in Croatia, by adoption of new REL (2015), support to new RES shall be granted through a competitive bidding process. Starting from 2017, EEAG [26] are requiring that any type of support in the form of operational support or investment-based should be granted through competitive procedures based on clear, transparent and non-discriminatory criteria (unless it is demonstrated that a competitive bidding process would lead to higher support levels or low projects realization rates - underbidding). In other words, operational support based on feed-in tariffs is no longer compliant with State aid rules from beginning of 2016 if it is opened to all market participants and it is not granted through a tendering process. A feed-in premium for the operational support is most suitable to replace the existing feed-in tariffs granted on the first-come, first-served basis. A feed-in premium, with the premium granted through a tendering process, is compatible with the internal market principles and will lead to a phase-out of the subsidies needed overtime while several technologies will reach market parity.

As observed recently in [25], countries in the region shall bring their support schemes in line with the EEAG. The Renewable Energy Coordination Group established by the Ministerial Council on Energy Community in 2015 will start working in 2016 on the reform of the support schemes for renewable energy producers to enable reaching the renewable energy targets by 2020 in the most cost-efficient way and in compliance with the principles of the internal market.

The introduction of feed-in premiums in order to replace the feed-in tariffs currently in place goes along the introduction of competitive electricity markets and establishment of trading platforms for day-ahead markets.

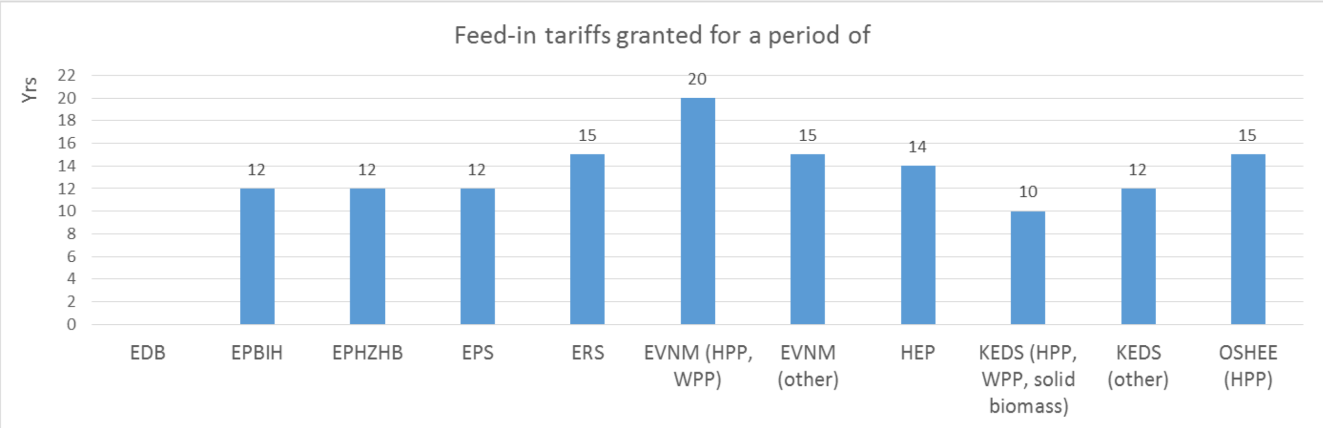


Figure 6.8 Period of granting fee-in tariffs in SEE DSOs

As provided in [25], exemption from balance responsibility for RES producers was initially introduced as part of the support scheme when support was granted in the form of feed-in tariffs. The EEAG (April 2014) [26] require that more market based exposure with an obligation of balance responsibility for renewable energy producers should be gradually introduced for new medium and large renewable energy producer starting in 2016. Projects with installed electricity capacity of less than 500 kW or demonstration projects, and projects using wind energy of less than 3 MW or 3 generations units should be exempted (EEAG, paragraph 125).

This could be introduced subject to emergence of competitive power and balancing markets in Croatia and the Energy Community Contracting Parties (Albania, BiH, FYROM, UNMiK) that will enable price signals from power and balancing markets to reach producers. Standard, non-discriminatory balance responsibility introduced for all market participants is key to enable transition to flexibility and cost-efficiency in use of the resources in a regional energy market. Transfer of balance responsibility to a balance responsible group (i.e. aggregator) should be allowed.

Table 6.5 Support scheme and renewable market operator for DGs in SEE DSOs

DSO	Who buys electricity produced in DGs	Promotion of renewable energy
EDB	n.a.	n.a.
EPBIH **EPHZHB**	In Federation of Bosnia and Herzegovina all incentivized renewable energy is bought by a newly established institution the "**renewable energy operator**"- as a single buyer. By REL (2013) "renewable energy operator" is obliged to buy electricity produced by qualified RES producers whose production is not incentivized and are within quotas defined by REAP (Renewable energy action plan; may 2014)(mandatory off-take at a reference price).	Federation of Bosnia and Herzegovina promote electricity generated from renewable sources through **feed-in tariffs**. In the Federation of Bosnia and Herzegovina support is granted for 12 years. Qualified producers are entitled to reference price, established according to a pre-defined methodology, for a period of 12 years.
EPS	**EPS Supply** is under an obligation to purchase all renewable energy generated by privileged producers under power purchase agreements.	Privileged producers are entitled to a **feed-in tariff**, established according to a pre-defined methodology based on capacity for energy from wind, hydro (**up to 30 MW**), solar PV, biomass, biogas geothermal, waste and landfill and sewage gas for a period of **12 years**. Feed-in premiums are not defined in the existing legislation.
ERS	**Unit** has been created **within ERS** which functions as a single buyer for incentivized renewable electricity. In the future, this role will be given to a separate company. The deadline for the establishment of a separate legal company fulfilling this function expired in December 2014. Producers that opt for selling the electricity on the market to other *suppliers* receive feed-in premiums.	**Feed-in tariffs** or **premiums** offered on top of an administratively set electricity market price and financed through an uplift charged on all final customers in Republic of Srpska. Support is granted for **15 years**.
EVNM	The **market operator** established within the transmission system operator MEPSO is obliged to buy all the electricity produced from preferential producers.	The Government adopted **feed-in tariffs** for electricity sold by eligible producers (wind, small hydro (**up to 10 MW**), biomass/biogas and photovoltaic). Feed-in tariffs for geothermal energy are envisaged Power purchase agreements are offered for **20 years** for hydro and wind, and **15 years** for solar PV, biomass and biogas. Loans for use of renewable energy sources, improving energy efficiency and saving energy.
HEP	Market operator (feed-in incentivised renewable electricity) Suppliers (net-metering)	Feed-in tariffs (PPA are offered for **14 years**) and loans (Environmental Fund-Loans, Croatian Bank for Reconstruction and Development).
KEDS	ERO Decision (12/2014) gives the possibility to renewable energy producers to conclude a power purchase agreement with the public supplier KEDS for electricity produced from renewable sources and cogeneration.	Feed-in tariffs RES Power Purchase Agreement (hydro energy, wind energy and solid biomass) have a duration of 10 years, whereas the electricity generated from solar/photovoltaic energy will have a duration of 12 years.

DSO	Who buys electricity produced in DGs	Promotion of renewable energy
OSHEE	Renewable Energy Law appointed the wholesale public supplier, the state-owned generation company KESH, as a single buyer of renewable energy from small HPPs (producers with capacities less than 15 MW). The purchase prices for electricity from old and new small HPPs are ("not a long term decision") based on the import price of electricity in the previous year, adjusted with an inflation index and approved annually by the Energy Regulatory Entity (ERE). The role of renewable energy operator that had been previously assigned to the wholesale public supplier is now removed by the Power Sector Law adopted in 2015. The appointment of a renewable energy operator to manage the incentive system for new renewable energy producers has not been decided yet. Based on the questionnaire response for this study, from 2016 DSO might be obliged to purchase electricity produced by SPPs connected to distribution network.	ERE adopted two different feed-in tariff methodologies for **small HPP** with installed capacity up to **15 MW**: for the existing small HPPs that were privatized or given through concession and for the new HPPs commissioned after December 2006. Proper support mechanism for energy from other types of renewable sources has to be adopted by ERE. KESH signs power purchase agreements for a period of **15 years**.

Table 6.6 outlines obligations of balance responsibility for DGs in SEE. It could be observed that until 2016 all RES producers are being exempt from paying for imbalances. Enactment of by-laws regulating balance responsibility of RES is planned:

- in Federation entity in BiH renewable energy operator shall establish a methodology for allocating costs of balancing to the privileged and qualified producers and the also share of costs of balancing that will be covered by RES fees collected from end customers, while the system operators (DSO) are required to prescribe methodology for prediction of production and delivery of data to operators for producer >150 kW,
- in Republic of Srpska Rulebook on financial settlement of imbalances of power plants under support scheme is under preparation,
- in Albania balancing groups, balance responsibility and balancing rules of TSO (OST) are to be included in a Transmission Operation Code (shall be developed by OST and approved by ERE),
- in Croatia renewable energy operator (market operator) shall adopt Rules on the management RES balance group by the end of March 2016.

In Serbia and Albania all privileged producers are exempted from balancing responsibilities and costs, while in Federation entity and Republic of Srpska entity in BiH the same applies to all power plants below < 500 kW and qualified producers (i.e. RES) <150 kW respectively.

In Croatia it is open whether small scale technologies will have to bear the imbalance costs, as well as existing eligible producers (i.e. retroactive changes which might undermine investors legitimate expectations).

Table 6.6 Balancing responsibility in SEE DSOs

DSO	Balance responsibility
EDB	n.a.
EPBIH	Qualified producers **<150 kW** are not required to submit daily generation forecasts to the "renewable energy operator" neither to take balance responsibility (pay for imbalances) Renewable energy operator shall establish a methodology for allocating costs of balancing to the privileged and qualified producers and the also share of costs of balancing that will be covered by RES fees collected from end customers. The system operators are required to prescribe methodology for prediction of production and delivery of data to operators for producer >150 kW (i.e. producers over 3 MW shall predict day ahead hourly production, while other producers over 150 kW and below 3 MW only weekly production).
EPHZHB	
EPS	**Privileged producers** are **exempted** from balancing responsibilities and costs during the entire 12 years. For other producers interconnected to distribution system (i.e. independent producers) provision from Energy Law (2014) are valid.
ERS	Financial settlement of imbalances planned **to start in 2016** Power plants **above > 500 kW** to be charged for imbalances, where PP under **feed-in** support scheme **pay 25% of imbalances** (75% is covered by the incentive fee for electricity production from RES and efficient cogeneration)**, and all other PP** (including PP under **premium** support **pay 100% of imbalances).** Rulebook on "Financial settlement of imbalances of power plants under support scheme" under preparation.
EVNM	Preferential producers are **not charged for their imbalance**. A balancing group created by the market operator takes balance responsibility for all preferential producers. Preferential producers with capacities above 10 MW have to submit daily physical nominations to the market operator. Starting 2015, large preferential producers are obliged to take balance responsibility.
HEP	No (but envisaged by drafted Law on Renewable Energy; starting from 2017) - under preparation.
KEDS	Producers of renewable electricity are required to pay only 25% of their imbalance. *For system security, they are obliged to forecast wind speed and submit it to the transmission system operator up to 30 hours ahead of scheduling time and to provide the wind speed measurement to the transmission system operator.*
OSHEE	Study questionnaire response - privileged producers are being exempted from payment of costs for imbalances. Balancing groups, balance responsibility and balancing rules of TSO (OST) are to be included in a Transmission Operation Code and based on objectivity, transparency and non-discrimination (Article 56 of the Law). The Transmission Operation Code will be developed by OST and approved by ERE.

7 TASK 1C: U.S. AND EU DSO - OVERVIEW OF RULES/REQUIREMENTS FOR INTEGRATING NEW DISTRIBUTED GENERATION AND APPLICABILITY IN SEE

7.1 U.S. decentralised resources portfolio

Figure 7.1 provides U.S. decentralized resources capacity in operation by State. Data are as of year-end 2012.

Decentralized resources (DR) are the aggregate of distributed, dispersed and net-metered generation. Distributed and dispersed includes commercial and industrial generators < 1 MW. Net metered refers to residential, commercial, and industrial generators < 2 MW. Distributed and net-metered are grid-connected and grid-synchronized. Dispersed generators are neither connected nor synchronized to the grid. *Figure 7.1* includes both actual and estimated and both utility and customer-owned generation. In 2012 decentralised generation in U.S. amounted 9.218 GW (0,87 % of U.S. electric generating capacity).

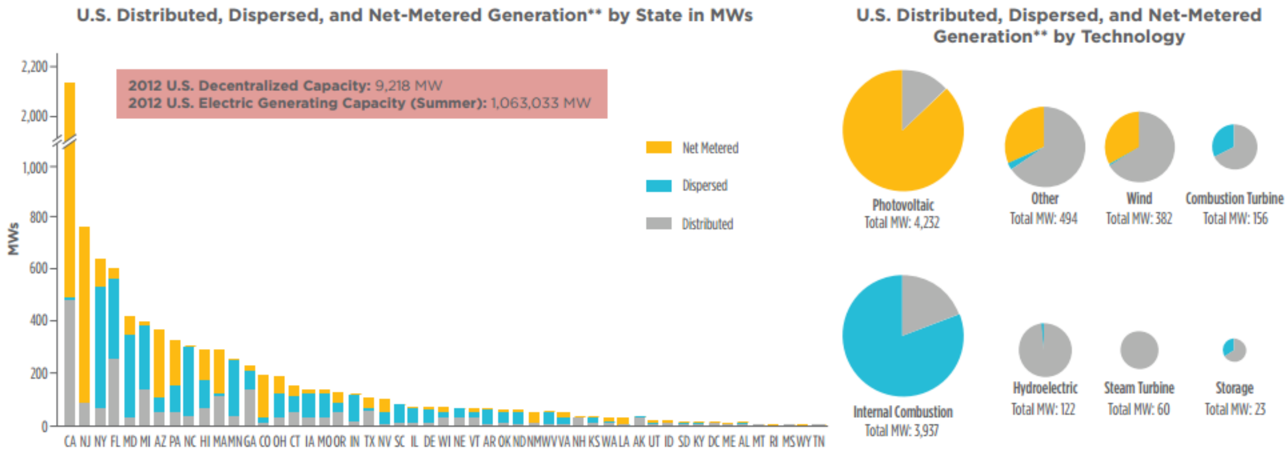


Figure 7.1 U.S. decentralized resources by State - data are as of year-end 2012
(source EIA Form 860 and 861 data [32]; the Scott Madden Energy Update (Winter 2015) [31])

Energy Information Administration (EIA) [32] is tracking yearly and monthly electricity generator additions (*Figure 7.3*). Monthly tracking became particularly important given the rapid increase in utility-scale (1 MW or greater) solar generating units, which have been installed at a rate of 24 plants per month in 2015 and account for nearly two-thirds of the total plants added in 2015. The full EIA's database includes 19.914 operating power plants with more than a million MW of net summer capacity (as of September 2015).

Small-scale solar PV installations, defined by EIA as having capacity of less than 1 MW (usually located at the customer's site of electricity consumption). These small-scale PV installations are also called behind-the-meter, customer-sited, or distributed generation capacity. Although each distributed PV system is very small—a typical size for residential PV systems is 5 kW (or 0,005 MW) —there are hundreds of thousands of these systems across the country that add up to a substantial amount of electricity generating capacity.

Small-scale distributed solar PV systems have grown significantly in the U.S. over the past several years. *Figure 7.4* depicts EIA U.S. estimation on small scale PV capacity and generation in 2014 and 2015. For example, the total U.S. solar generation (PV and thermal) was 3,6 million MWh in September 2015, with 33 % of that total coming from small-scale solar PV. Overall, U.S. solar generation, including both small-scale distributed PV and utility-scale PV and thermal solar generation, was equivalent to about 1,0% of total reported electricity generation from all operable utility-scale sources in U.S. in September 2015 (*Figure 7.2*).

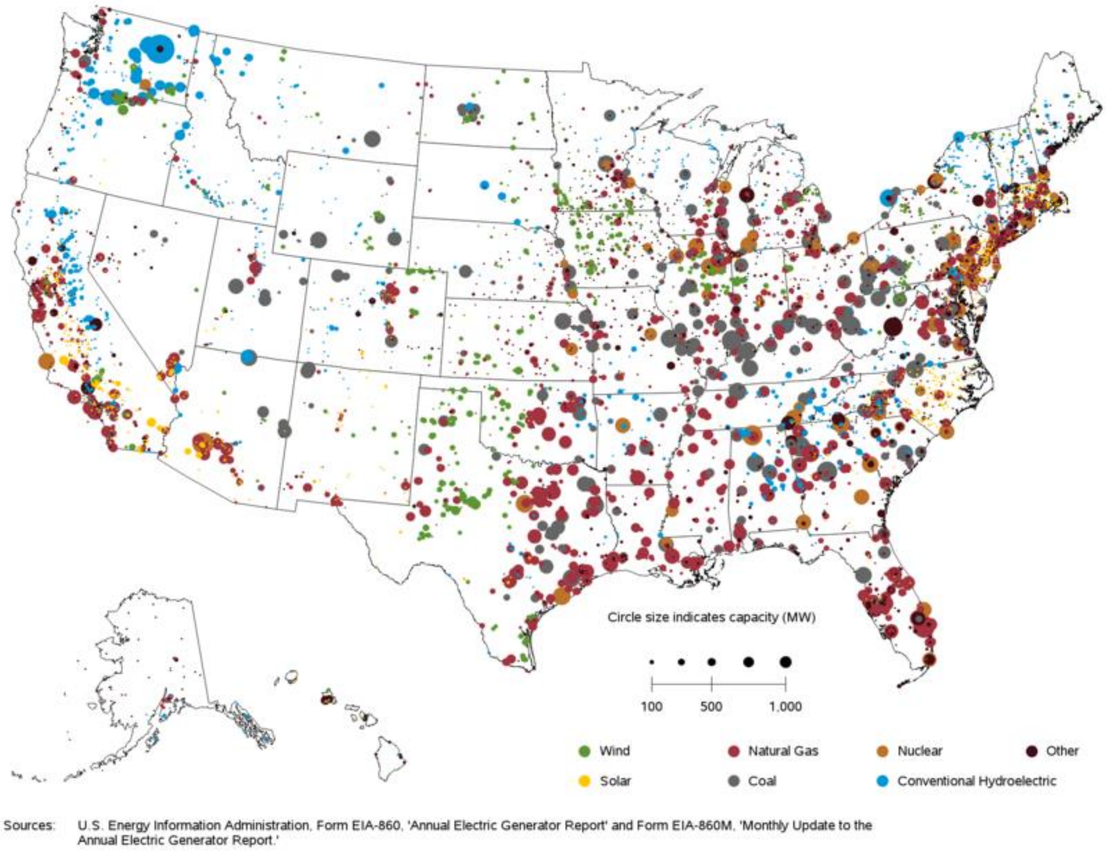


Figure 7.2 U.S. operable utility-scale generating units - as of September 2015 (source EIA [32])

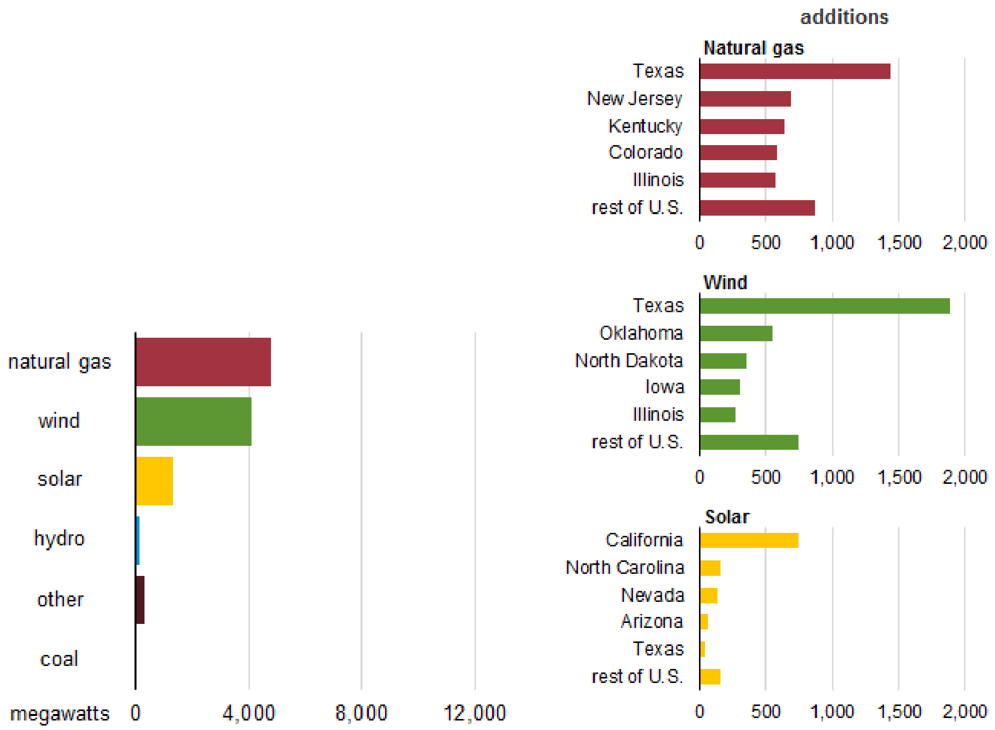


Figure 7.3 U.S. generating capacity additions in 2015 by fuel type in MW (through September) – top 5 states (source EIA [32], Form EIA-860)

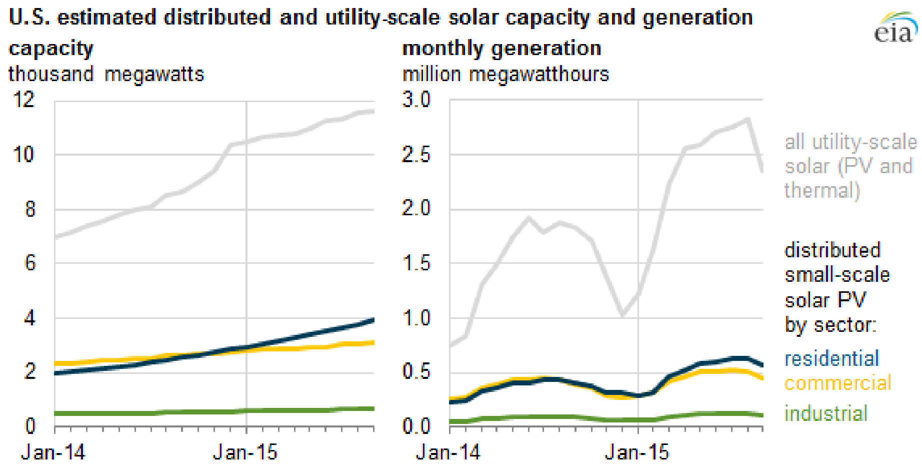


Figure 7.4 U.S. estimated distributed and utility-scale solar capacity and generation (source EIA [32])

Almost 40 % of the distributed PV capacity in the U.S. is located in California, with the next nine states accounting for another 44 % (*Figure 7.5*). The remaining 40 states and the District of Columbia combined have the remaining 16 %. California is not only the most populous state, but it is also home to other factors that encourage distributed PV generation: high electricity prices, strong solar resources, and state policies and incentives that support solar PV. Other top states share some but not all of these factors. New Jersey, Massachusetts, and New York are top distributed solar states despite relatively less favourable solar resources because of consistent state solar PV policies and incentives and some of the highest residential electricity prices in the country. Other states, like Arizona, have incentive programs and strong solar resources. Hawaii has a small population, but its strong solar resources and high electricity prices make rooftop solar PV systems economically attractive.

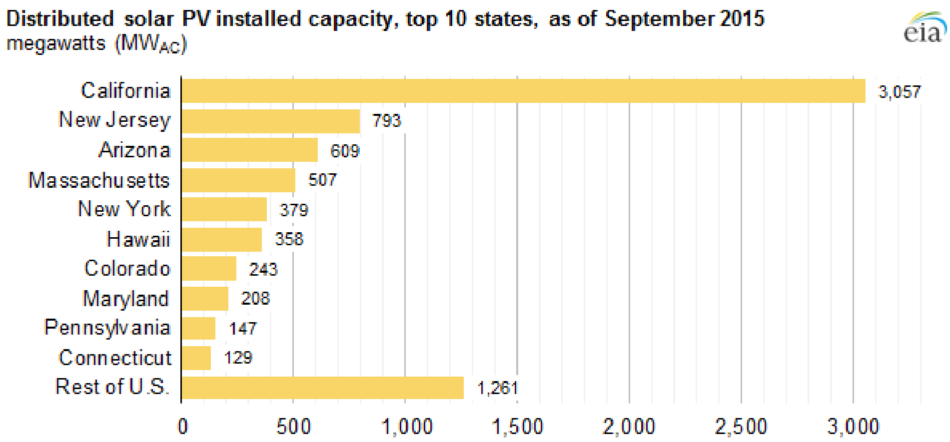


Figure 7.5 U.S. Distributed solar PV installed capacity in U.S. – top 10 States (as of September 2015) (source EIA [32])

By the end of 2015, the United States will need to interconnect more than 30 GW of new renewable generating capacity to meet existing state and federal renewable energy policy goals. By 2035, the additional generating capacity needed to satisfy existing policy goals increases to 100 GW.

It could be observed that in U.S. customer investments in clean energy sources are rising at a tremendous rate even as state incentives reach their lowest levels in a decade—and in some cases, having accomplished their intended purpose, have gone away entirely. Against this backdrop of newfound market maturity, net metering and interconnection serve to keep the way clear for customers to continue choosing clean energy.

7.2 U.S. utility interconnection practices (rules, guidelines, limits)

As recognised in [28], state and federal interconnection policies, which clarify the steps and responsibilities for interconnecting new generating facilities to the electric power system, have a direct and substantial impact on the timing and cost of bringing new generating capacity online. Interconnection policies address complex, technical issues, and the utilities and developers that engage in the process often have divergent views about the goals the process should aim to achieve:

- From a utility standpoint, the interconnection of even a small generator can raise potential safety and reliability impacts that may need to be addressed. Utilities are thus inclined to want sufficient time to process interconnection applications to protect against any diminution in safety, reliability and service quality that may expose the utility to increased levels of risk. If there is any possibility for reliability or safety impacts, utilities will want to study those impacts to determine appropriate protective or mitigating measures.
- For developers, the interconnection process is one of the most time-consuming and costly aspects of developing a generating facility. Frequently, developers claim that the process is opaque and consists largely of internal utility business practices such that implementation varies drastically from utility to utility. Moreover, this lack of transparency and certainty introduces significant development risk. Delays in the interconnection process slow development and may undermine access to valuable tax incentives and utility solicitations.

Regulators are faced with the often challenging task of balancing these divergent perspectives to find "win-win" solutions that allow utilities to maintain the safety and reliability of electric power systems while providing developers a transparent, efficient, and cost-effective process that operates on reasonably predictable timeframes. Regulators are also faced with the challenge of keeping interconnection processes up to date against a backdrop of evolving technology, updates to relevant codes and standards and changed market conditions.

Interconnection jurisdiction in U.S. is as follows:

- transmission level interconnections:
  - governed by federal policy and overseen by the Federal Energy Regulatory Commission (FERC),
  - generally apply to large-scale merchant generation sources,
- distribution level interconnections:
  - governed by state policy and administered by state Public Utility Commissions (PUC),
  - generally apply to DG behind-the-meter, residential and commercial facilities that are net-metered.

In U.S. there is a variety of interconnection-related requirements that the DSOs implement. Technical codes and standards consist of the technical requirements for safely interconnecting new generating facilities to the electric grid while maintaining reliability. The technical aspects of interconnection are governed by codes and standards developed by various organizations. Standardisation organisations relevant to the interconnection of DR in the USA are the following:

- National Fire Protection Association: NFPA (which published the National Electric Code: NEC; NFPA is the foremost organization in the U.S. dealing with electrical equipment and wiring safety; the scope of the NEC covers all buildings and property except for electric transmission and distribution utility (TDU) property, i.e. all equipment on the customer's side of the point of common coupling (the meter)),

- Institute of Electrical and Electronics Engineers: IEEE (which issued for example the IEEE 1547 series) [17],
- Underwriters Laboratories: UL (safety testing and certification organisation, issued for example UL 1741) [18].

In the following, several guidelines and regulations, applicable in U.S., are outlined. A fundamental idea in most of them is that the DSOs set specific thresholds concerning several technical criteria (short-circuit, load to generation ratio etc.) that are considered to provide a safe-side evaluation of the hosting capacity of the network. If these criteria are met, no additional studies are required, otherwise specific studies have to be carried out.

7.2.1 History of small generator interconnection procedures

As given in [28], existing interconnection processes for small generators were largely developed between 2000 and 2006 with few significant updates since that time. Prior to 2000, few states had uniform interconnection procedures. Instead, utilities regularly determined the procedural requirements that would govern the interconnection process on a case-by-case basis.

For lack of another proven approach, many utilities applied interconnection procedures they had in place for qualifying facilities under the federal Public Utility Regulatory Policies Act of 1978. These procedures were largely designed for facilities interconnecting to high-voltage transmission lines and were often more cumbersome and expensive than what was needed for smaller facilities interconnecting to low- and medium-voltage distribution lines. This created inefficiencies in which lengthy and costly studies were often required only to determine that upgrade costs would make a generator financially infeasible. This was particularly problematic for modestly-sized residential and commercial solar PV systems that were primarily intended to serve onsite energy needs.

Over the last decade, the renewable energy industry, states, and utilities have cooperated in creating model interconnection procedures for regulators to use when developing state procedures. The more prominent examples are the FERC Small Generator Interconnection Procedures (SGIP), California Rule 21, the Mid-Atlantic Distributed Resources Initiative (MADRI) model rule, and the Interstate Renewable Energy Council (IREC) model rule. FERC's SGIP and California Rule 21 are not technically "models"; they were created as procedures to be put into actual practice. These procedures have, however, been used by some states as a model for developing their interconnection procedures and, therefore, are often referred to as model procedures. The SGIP was influenced by the Small Generation Resource Interconnection Procedures developed by the National Association of Regulatory Utility Commissioners (NARUC) in 2003 and submitted to FERC early in the Order 2006 proceeding. The NARUC procedures were also the genesis of the IREC and MADRI rules but have not been updated since 2003 (NARUC 2003).

December 2000: California's Rule 21

In 2000, California was among the first states to adopt comprehensive procedures for distribution system interconnections when the California Public Utilities Commission adopted Rule 21 (see section 7.4.3). Rule 21 implemented a screening process through which utilities could easily and objectively review an interconnection application to determine whether further studies or additional protective measures may be required. The initial review screens were designed primarily to ease the interconnection process for generators intended to serve onsite load. Rule 21 also included timelines to ensure the interconnection process would move forward in a timely manner. Since California was among the first states to thoroughly address the interconnection process for a distribution system interconnection, the state's Rule 21 served as a basis for the development of technical standards, federal rules and other state procedures in subsequent years.

June 2003: IEEE 1547 Standard

In 2003, the IEEE developed technical Standard 1547: The Standard for Interconnecting Distributed Resources with the Electric Power System. Standard 1547 provides requirements relevant to the performance, operation, testing, safety considerations and maintenance of distributed resources interconnection with electric power systems. Specifically, it provides comprehensive guidelines for "responses to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning, and periodic tests." It was developed through an extensive, consensus-based stakeholder process and has since received widespread support and has informed the technical requirements found in federal and many state interconnection policies for small generators. The criteria and requirements in this standard are applicable to all distributed resource technologies, with aggregate capacity of 10 MVA or less at the PCC interconnected to EPS at typical primary and/or secondary distribution voltages. However, some U.S. states apply IEEE Standard 1547 to larger distributed generation.

The IEEE 1547 standard is not a single static standard. However, it is the first in a family of standards, with the intent that later IEEE 1547.1 through .8 standards be used in conjunction with standard IEEE 1547. The evolving series of IEEE 1547 standards (*Figure 7.6*) include IEEE subgroups developing guidance and recommended practices: a) to determine the appropriate criteria, scope and extent of distribution impact studies for distributed resource interconnections, and b) to address changes to the current standard to accommodate high penetrations of intermittent generators. Although this work will undoubtedly inform future modifications to state and federal interconnection processes, there is much in the way of screening and processing of interconnection applications that IEEE standards do not address.

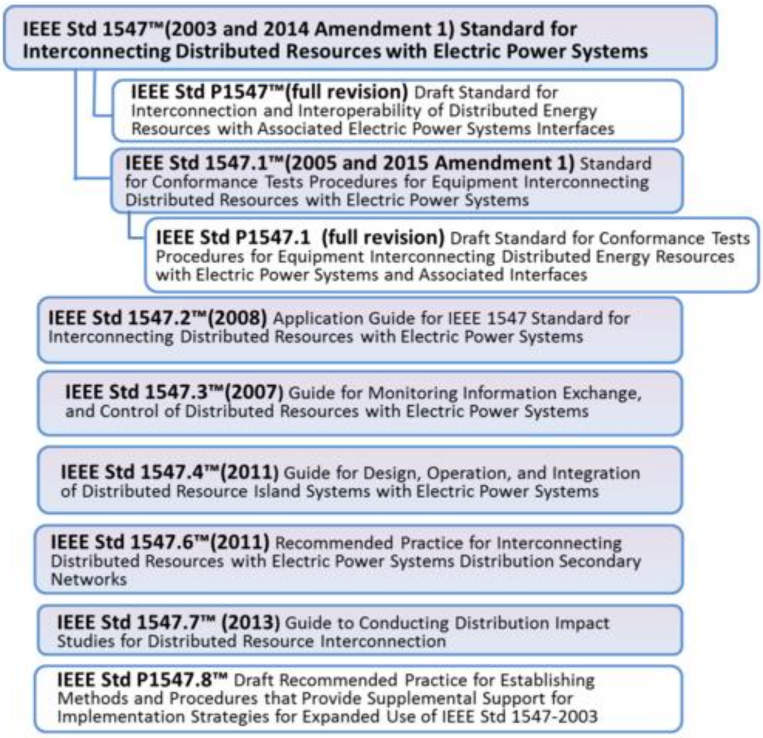


Figure 7.6 IEEE 1547 Series of Interconnection Standards

(note: colored background designates IEEE published standard; clear background is draft standard work in progress)

A notable limitation of the 1547 standard is that it does not address technical considerations defining the maximum allowable amount of generation beyond the point of common coupling—the point at which one generating facility is physically interconnected to the utility electric power system. Standard IEEE 1547 does not address operations and impacts upstream or downstream from that point. In addition, it does not address non-technical issues such as the timeframe or cost of interconnection. These issues are left to the determination of regulators in the development of interconnection processes and other valuations.

Observing certain undesirable impacts of distributed generation on the grid and recognizing the potential benefits of emerging inverter-based Distributed Energy Resources (I-DER) capabilities, the IEEE recognized that an update to the 1547 interconnection standards for I-DER interconnected to North American distribution systems was required. In mid-2013 the IEEE members of the 1547 standards community initiated a "fast-track" amendment to IEEE 1547, labelled IEEE 1547a. The focus of the IEEE P1547a - Amendment 1 WG was limited to establishing updates to voltage regulation, response to area electric power systems abnormal conditions of voltage and frequency, and considering if other changes to IEEE 1547 standard were absolutely necessary in response to the updates that were established under preceding topics of the amendment.

Balloted and approved by IEEE in September 2013, IEEE 1547a is a update to the existing IEEE 1547: its main purpose is to permit some DER actions that are not currently allowed in the IEEE 1547 standard. For example, IEEE 1547a permits the DER system to actively regulate voltage at the point of common coupling under certain conditions. IEEE 1547a also permits the high and low limits of voltage and frequency to be extended for specific time periods so that voltage and frequency ride-through by DER systems can occur.

Amendment 1 published in 2014 was an result of the IEEE-hosted SCC21 May 2012 Workshop. More than 80 industry participants collaborated in the IEEE-hosted workshop, and recommended a revised title, scope, and purpose to launch an IEEE SCC21 project and working group to complete a full revision of the IEEE 1547 standard before 2018.

IEEE is currently developing IEEE Standard 1547.8, Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Standard 1547, which will likely address systems larger than 10 MVA.

2004/2005: Mid-Atlantic Distributed Resources Initiative

Mid-Atlantic Distributed Resources Initiative (MADRI) was established in 2004 by the public utility commissions of Delaware, the District of Columbia, Maryland, New Jersey, and Pennsylvania, along with the Department of Energy (DOE), the Environmental Protection Agency (EPA), FERC, and the PJM Interconnection [37]. The MADRI procedures contain four levels of DG interconnection review based on the DG size. The MADRI model interconnection procedures were developed through a stakeholder process and finalized in November 2005. The model was created as an alternative to the FERC SGIP and is meant to be used as a guide for states to develop their own interconnection procedures specific to their particular jurisdictional needs.

- Level 1 is for inverter-based systems with nameplate capacities of 10 kVA or less,
- Level 2 is for inverter-based systems with nameplate capacities up to 2 MVA including any 10 kVA and smaller systems that did not pass the screens for Level 1,
- Level 3 is for all systems up to 10 MVA in size including those that did not pass the Level 1 and/or Level 2 screens,
- Level 3A, which is unique to the MADRI model, is a potentially expedited review procedure for systems that will not be exporting power to the grid. This level grants utilities discretion to connect non-exporting systems up to 10 kVA to their distribution grids if they determine there will be no adverse impacts. States using the MADRI model can also consider utility-supplied alternative text that allows Level 3A to apply to systems up to 50 kVA in size (MADRI 2005).

Though not entirely adopted by any state, the MADRI model has been used to develop interconnection procedures in Illinois, Maryland, Oregon and Pennsylvania.

May 2005: FERC Small Generator Interconnection Procedures (see section 7.2.2)

August 2005: Energy Policy Act of 2005

A survey in 2000 by National Renewable Energy Laboratory (NREL) found that virtually all DG projects met some sort of resistance from utilities when they try to interconnect with the grid. Partly in response to that finding, Congress included Section 1254 in the Energy Policy Act of 2005 (EPAct '05), which required state regulatory commissions and certain non-regulated utilities to consider adopting interconnection procedures based on the IEEE 1547 standard and current "best practices."

Energy Policy Act of 2005 can be seen as a catalyst for a significant amount of state action as it modified the Public Utility Regulatory Policies Act (PURPA) to require state public utility commissions to "consider" standards for net metering and interconnection.

At least 31 states adopted or amended their interconnection processes in some form or another in the years following the enactment of EPAct '05. Many of these states modelled their interconnection policies on FERC's SGIP. A few Western states modelled their procedures on California's Rule 21. However, it is not clear whether these policies were adopted as a result of federal law. It is evident, however, that EPAct '05 had a significant impact by raising awareness about interconnection issues and by spurring dialogue at a state regulatory level. As of December 2015, 44 states plus the District of Columbia and Puerto Rico had adopted interconnection policies (see section 7.2.3).

2005/2006: Interstate Renewable Energy Council

IREC is a non-profit organization created in 1982 [38]. The IREC model procedures were originally developed in 2005, finalized in November 2006, and updated and revised in 2009. The IREC procedures have four levels of DG interconnection review, three of which are based on project size:

- Level 1 contains a set of simplified screens for inverter-based systems with a capacity of 25 kW or less,
- Level 2 is a set of screens for systems with a capacity of 2 MW or less, including those below 25 kW that did not pass Level 1 screening,
- Level 3 is for systems that have a capacity of 10 MW or less and will not be exporting power to the grid,
- Level 4 is for all systems that did not qualify for the Level 1, Level 2 or Level 3 interconnection review processes (IREC 2009).

The IREC procedures drew on the previous models developed by FERC, MADRI and NARUC. The IREC model attempts to incorporate the best approaches and features found in the work done to date on interconnecting distributed generators. Over the past decade, IREC has worked with dozens of states across the country to facilitate and support the adoption of fundamental regulatory policy reforms.

IREC updated its model interconnection procedures earlier in 2014 to reflect emerging best practices (e.g. Level 2 applies to generating facilities of up to 5 MW depending on line capacity and distance from substation; see table below).

Line Capacity	**Level 2 Eligibility**	
	Regardless of location	**On ≥ 600 amp line and ≤ 2.5 miles from substation**
≤ 4 kV	< 1 MW	< 2 MW
5 kV – 14 kV	< 2 MW	< 3 MW
15 kV – 30 kV	< 3 MW	< 4 MW
31 kV – 60 kV	≤ 4 MW	≤ 5 MW

7.2.2 Federal USA

The FERC is an independent agency that regulates the interstate transmission of electricity, natural gas and oil in U.S. In the United States, the Federal Power Act (FPA) grants FERC jurisdiction over interstate commerce with respect to energy (both electricity and fuels), which is generally understood as jurisdiction over all aspects of wholesale power markets.

Related to wholesale generator interconnection, FERC issued Order 2003 in 2003 to establish the standard procedures governing large generator interconnection, including the standard Large Generator Interconnection Procedures and the standard Large Generator Interconnection Agreement, for all FERC-jurisdictional facilities with a capacity greater than 20 MW.

In 2005, FERC established pro forma Small Generator Interconnection Procedures (SGIP) and a pro forma Small Generator Interconnection Agreement (SGIA) that establish the terms and conditions under which transmission providers must provide interconnection service to generating facilities of no more than 20 MW. Under those procedures, a generator makes an interconnection request and the transmission provider then evaluates whether the generator can be interconnected to the grid safely and reliably.

The FERC SGIP was vetted by a broad range of industry participants and adopted through FERC Order 2006 in May 2005, and Orders 2006-A and 2006-B in the subsequent year. The SGIP and SGIA apply to FERC jurisdictional interconnections, including facilities that a) interconnect to FERC-jurisdictional transmission systems, or b) interconnect to FERC-jurisdictional distribution systems to sell wholesale generation in interstate commerce (e.g. a wholesale generator is already interconnected with the specific distribution line and the distribution line is covered by a FERC-approved Open Access Transmission Tariff).

SGIP includes three levels of review:

- Level 1 is a “Simplified” screening process for certified inverter-based systems less than 10 kW,
- Level 2 is a "Fast Track Process" for eligible generators no larger than 2 MW,
- Level 3 is a “Study Process” for all other systems 20 MW or less.

SGIP applies ten interconnection screens for the first two review levels, including the previously noted screen that requires an interconnection study for generators that cause aggregate generation capacity to exceed 15 % of annual peak load on a line section of a radial distribution circuit. It is worth to mention that recently [28] this screen in many federal and state interconnection processes has been perceived as a significant barrier to PV deployment by many solar developers and other stakeholders, which is way modifications have been required to the screening process to include PV-specific screening criteria that better account for the daytime generating profile of solar PV in a short-term period, and also work toward more widespread interconnection reform in a long-term period.

In January 2013 (amended in September 2014), FERC issued Order No. 792-A [27], adopting revisions to its rules for interconnecting small generation facilities to the grid. The new rules provide new protections for small generators, additional flexibility in qualifying for a “Fast Track” interconnection process, and extend FERC’s pro forma interconnection procedures and agreement to energy storage resources. While the 2013 rules apply to all generators of no more than 20 MW, they should be especially helpful to solar facilities and to energy storage resources.

The reforms proposed intended to reduce the time and cost to process small generator interconnection requests and allow for more efficient interconnection of these resources to benefit customers. They were driven by market changes spurred in part by state renewable energy goals and policies. Four major reforms were proposed to the SGIP and SGIA:

- The first reform allowed interconnection customers to request from transmission providers a pre-application report to help them better evaluate points of interconnection before submitting a formal interconnection request. This added transparency could increase the efficiency of the interconnection process for both transmission providers and interconnection customers.
  The pre-application report provides readily available information about system conditions at any possible interconnection point. These reports are expected to help a customer select the best site for its facility, eliminate uncertainties, and reduce developer costs and schedule delays. Transmission providers should also benefit because the reports should diminish the practice of multiple interconnection requests for a single project.
- The second reform revised the current 2 MW threshold for participation in the “Fast Track Process” of the SGIP. Fast track eligibility is based on individual system and resource characteristics up to a limit of 5 MW. FERC made the following changes regarding eligibility for the Fast Track Process:
  - The eligibility threshold for inverter-based machines is based on the capacity of the generator and the line voltage and location of the interconnection. Under certain conditions, inverter-based facilities up to 5 MW are eligible. This change should allow more solar facilities to use the “Fast Track Process”.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline[1] and ≤ 2.5 Electrical Circuit Miles from Substation[2]
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

[1,2] FERC Order 792 allows larger systems to interconnect under the “Fast Track Process” if the system is on a "mainline" and less than 2,5 electrical circuit miles (CM) from a substation. In the order, FERC defines a "mainline" to be "the three-phase backbone of a circuit" that will "typically constitute lines with wire sizes of 4/0 American wire gauge, 336,4 kcmil, 397,5 kcmil, 477 kcmil and 795 kcmil." The new requirement that utilities provide developers of interconnecting systems with a pre-application report also requires that the distance to the substation be provided in that report.

  - The eligibility threshold for synchronous and induction machines remained at 2 MW.
  - All projects interconnecting to lines greater than 69 kV are no longer eligible for the “Fast Track Process”.
- A third reform revised the customer options meeting and supplemental review for projects that fail the “Fast Track” screens that identify reliability or safety issues.
  Under the 2006 rules, if an interconnection customer fails the screens for Fast Track eligibility, the transmission provider must offer to perform a supplemental review, but only if the transmission provider concludes the review might determine that the facility could qualify for the Fast Track Process. Under the new rules, the transmission provider must offer to perform a supplemental review without condition (i.e. at the customer’s discretion) and the review must include three screens to determine if the small generating facility may be interconnected safely and reliably: (1) a minimum load screen; (2) a power quality and voltage screen; and (3) a safety and reliability screen.

- Finally, the pro forma SGIP Facilities Study Agreement has been revised by giving interconnection customers an opportunity to provide written comments on the upgrades that are necessary for the interconnection. In other words, in cases where a facilities study must be performed and the study identifies upgrades that are required, customers will now be allowed to provide written comments on the required upgrades. FERC observed that this dialogue with the transmission provider will help ensure that interconnection costs are just and reasonable. However, FERC recognised the transmission provider should make the final decision on upgrades required because it is ultimately responsible for the safety and reliability of its system.

FERC also adopted the following revisions with respect to the interconnection of energy storage devices:

- The definition of Small Generating Facility is modified to explicitly include storage devices.
- When determining whether a storage device may interconnect and/or qualifies for the "Fast Track Process", the transmission provider should generally use the maximum capacity that the device is capable of injecting into the system. However, under certain conditions something less than maximum injection capacity may be used for facilities that combine generation resources with storage resources (e.g. a storage facility operating to firm a variable energy resource).
- A transmission provider may study the effect on its system of the absorption of energy by the storage device and make determinations based on the outcome of these studies.

Although SGIP was developed to govern FERC-jurisdictional interconnections (i.e. transmission providers must make compliance filings), it can also serve as a model that state regulators may use as a starting point for developing their own interconnection procedures and agreement.

7.2.3 Distribution-level interconnection policies

In U.S. small generators are generally considered as those having a capacity of 20 MW or less. Facilities sized 20 MW or smaller do not often interconnect to transmission lines that fall under FERC jurisdiction, but because connecting generation facilities in the 5 to 20 MW range to the distribution system may be difficult, some generation facilities in this capacity range do connect to FERC-regulated transmission lines. The majority of small residential and commercial systems interconnect with utility-level distribution systems and are therefore under the jurisdiction of state-level regulations or, if unavailable or non-applicable, to utility-imposed interconnection guidelines. Facilities up to 2 MW in capacity rarely interconnect with anything other than utility-level distribution systems, which can include medium voltage class equipment.

State level interconnection procedures for non-FERC jurisdictional projects have set various size limits ranging from less than 100 kW to 80 MW facilities, while some procedures contain no specified size limits and can therefore be used to interconnect any project as long as the interconnection does not fall under FERC jurisdiction. *Figure 7.7* outlines the various state procedure size limitations.

Setting a low capacity limit can leave a gap in regulatory oversight, which may limit the development of certain projects that are not wholesale generators and therefore not FERC-jurisdictional, yet too large to be able to apply under state interconnection procedures. States like California, Hawaii, Indiana, Illinois, Maine, Massachusetts, Michigan, New Jersey, North Carolina Rhode Island and Vermont—have created procedures (or amended existing ones) that do not have capacity limits, thereby allowing state interconnection procedures to potentially be used by projects of any capacity not falling under FERC jurisdiction.

Figure 7.7 also outlines states with distribution-level interconnection policies (as of February 2013). As of December 2015, all but the following six states have adopted some form of interconnection standards with varying capacity limits: Arizona, Oklahoma, Idaho, North Dakota, Tennessee, Alabama (source DSIRE [36]). On December 2015, the Mississippi Public Service Commission (PSC) established net metering in the State accompanied by interconnection standards for distributed generator facilities, with procedure size limitation on 2 MW.

Here it must be indicated that Database of State Incentives for Renewables & Efficiency (DSIRE) web site is the comprehensive source of information on incentives and policies that support renewables and energy efficiency in the United States. Established in 1995, DSIRE is operated by the N.C. Clean Energy Technology Center at N.C. State University and is funded by the U.S. Department of Energy (DOE). On DSIRE website SEE DSOs can find links to interconnection rules and competent organizations for each U.S. state.

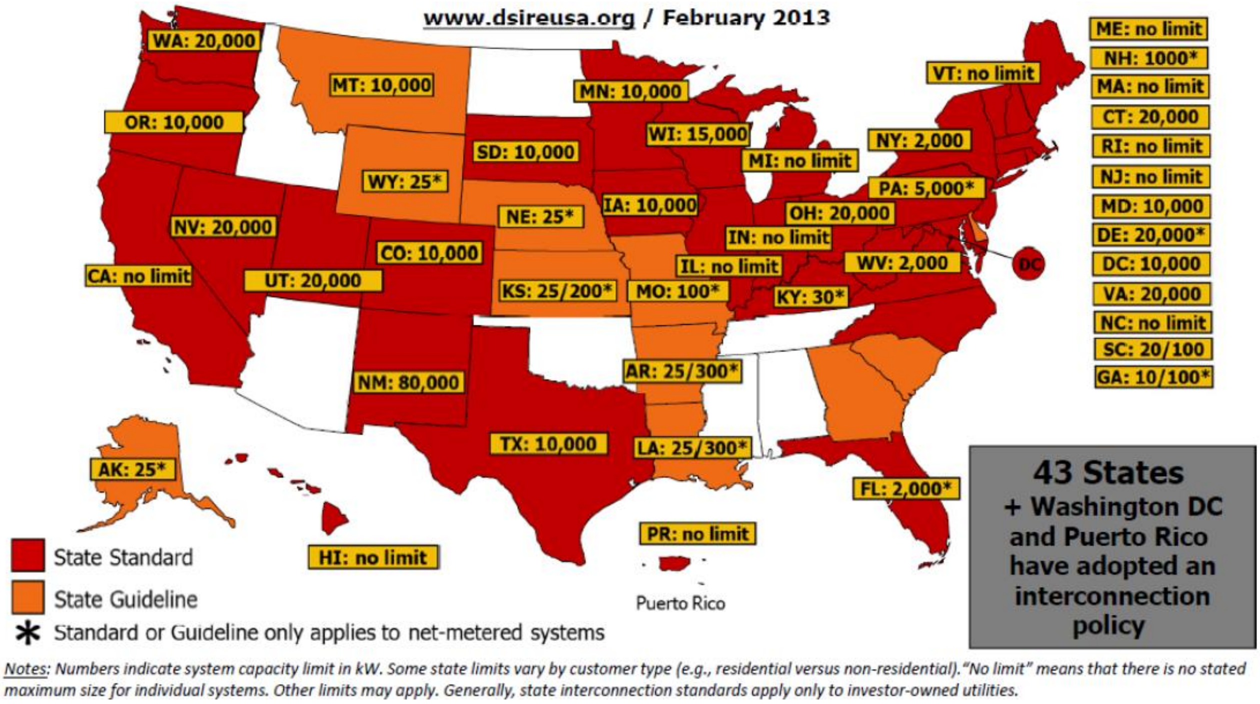


Figure 7.7 States with distribution-level interconnection policies (source [30])

Procedures in state interconnection rules deal with the protocols of reviewing an application for a DG interconnection and the process for the required studies to ensure the interconnection is safe, does not adversely affect power quality for other customers and is compliant with the rules. The procedures detail the methodology the utility and applicant must follow. Most state rules include 3-4 levels of review, depending on the size and type of DG and the characteristics of the grid feeder on which it will be interconnected. In many cases, the levels are based on those established in the FERC or MADRI procedures (see sections 7.2.1 and 7.2.2).

If the application does not pass the "technical screens" for a particular level, it moves up to the next level, with more stringent study requirements. These screens deal with issues like penetration of distributed generation on the feeder and other local grid parameters. Lower review levels allow for interconnection without a detailed impact study, although the screens themselves could be considered a simple impact study. Small (e.g. less than 10 kW), inverter based distributed generation interconnected to radial systems are at the lower end (Level 1), with larger units and more complicated interconnections at the higher levels (Levels 2 to 4). Impact studies typically are required at the higher review levels and always for Level 4.

The higher review levels (Level 2 and beyond) typically involve the following steps for the review process:

- *Scoping Study*: the purpose of the scoping study (often a meeting) is to discuss the interconnection request and review existing studies.

- *Feasibility Study*: the feasibility study determines if there are obvious adverse impacts identified before additional studies are undertaken for the proposed project to continue in the process.
- *System Impact Study*: the system impact study identifies the electric system impacts that would result if the proposed DG was interconnected without DG project modifications or utility electric system modifications, focusing on the adverse system impacts identified in the feasibility study. System impact studies can include the following individual studies:
  - analysis of equipment interrupting ratings,
  - distribution load flow study,
  - flicker study,
  - grounding review,
  - power flow study,
  - power quality study,
  - protection and coordination study,
  - short circuit analysis,
  - stability analysis,
  - steady state performance,
  - voltage drop study.

  In some cases, other specialized system impact studies also are required.
- *Facilities Study*: the facilities study determines the specific utility equipment and changes necessary to complete the interconnection and the associated costs. This equipment will mitigate the adverse systems impacts caused by the DG.

It could be concluded that almost all state rules are already technology-neutral, allowing for interconnection of all types of distributed generation (i.e. inverter-based, induction machines, and synchronous machines). Some states only allow certain technologies for certain review levels (e.g. inverter-based for Level 1).

Procedures generally contain milestone schedules, stating how quickly the interconnection application will be reviewed and specifying a certain amount of time the utility and applicant can take to complete the above steps (see section 7.5).

Many states require equipment to be compliant with certain standards or “certified” to qualify for some review levels. However, states define “certified” in slightly different ways.

Standard application and agreement forms make the interconnection process more transparent. Most states have simpler, shorter application and agreement forms for Level 1 interconnection that is processed in an expedited fashion. Standard-form interconnection agreements may be included in the state interconnection rule, or utilities may be required to file such agreements with the state PUC consistent with the rules and any model agreement established in the rulemaking proceeding.

Besides DSIRE, additional valuable source of information is IREC and the Network for New Energy Choices that periodically release a report entitled *Freeing the Grid* [35]. *Freeing the Grid* report examines state net-metering and interconnection standards and identifies best and worst practices. It contains a ranking system and assigns a letter grade to each state’s procedures (A-F). The rankings are based on the following criteria:

- set fair fees that are proportional to a project’s size,
- cover all generators in order to close any state-federal jurisdictional gaps,
- screen applications by degree of complexity and adopt simplified rules for residential-scale systems and expedited procedures for other systems,
- ensure that policies are transparent, uniform, detailed and public,

- prohibit requirements for extraneous devices, such as redundant disconnect switches, and do not impose additional liability insurance requirements above and beyond what is typically carried by the respective customer class,
- apply existing relevant technical standards, such as IEEE 1547 and UL 1741,
- process applications in a timely manner utilizing standardize and simplify forms.

The following 5 states are graded A/A regarding net-metering/interconnection standards implying therefore to have best practices in these regards: California, Massachusetts, Ohio, Oregon and Utah. In addition 2 more states: New Mexico and Virginia, are A graded regarding interconnection standards (*Figure 7.8*).

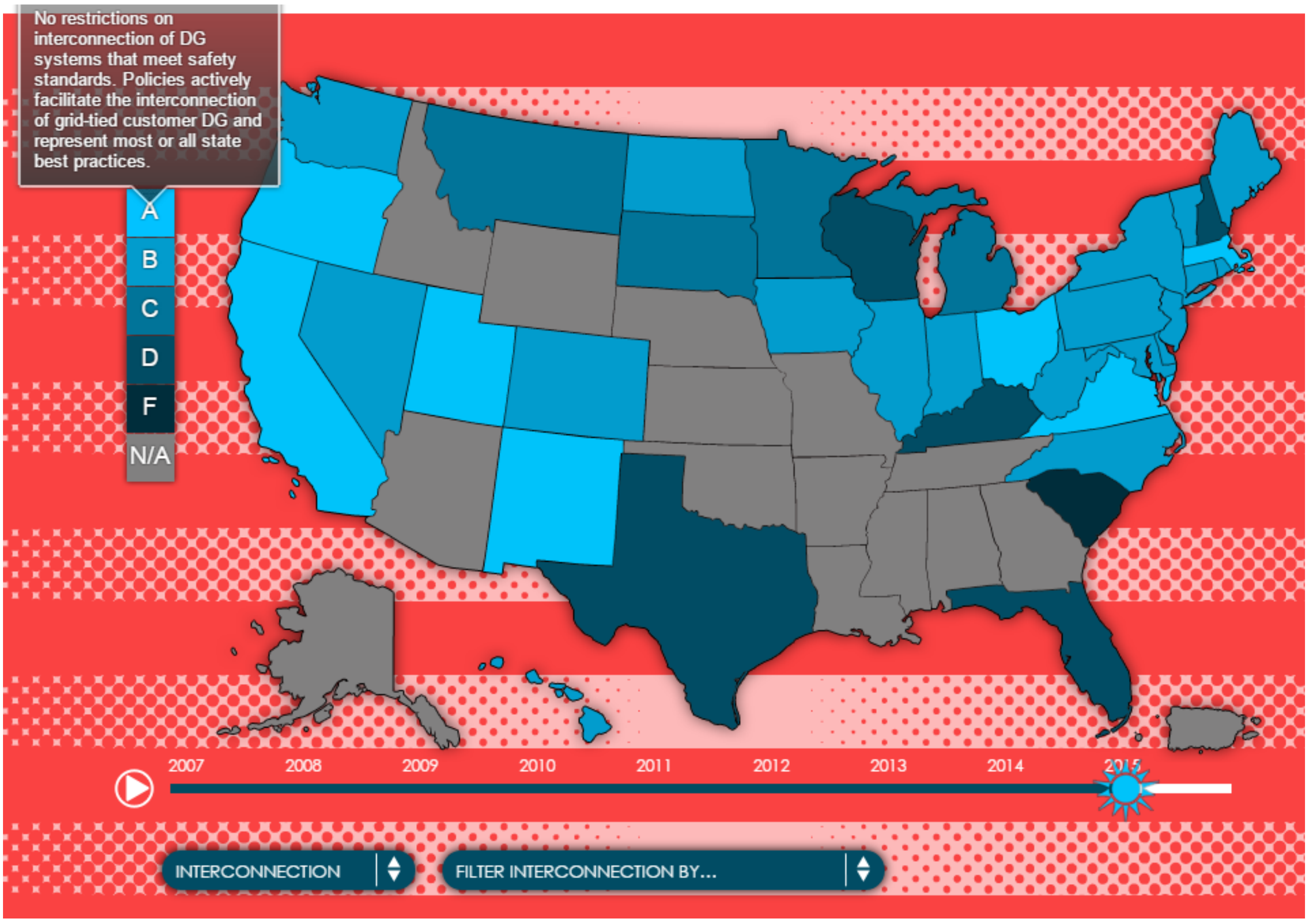


Figure 7.8 U.S. states interconnection procedures letter grades (source [35])

Freeing the Grid letter grades have the following meaning:

- A – No restrictions on interconnection of DG systems that meet safety standards. Policies actively facilitate the interconnection of grid-tied customer DG and represent most or all state best practices.
- B – Good interconnection rules that incorporate many best practices adopted by states. Few or no customers will be blocked by interconnection barriers. There may be some defects in the standards, such as a lack of standardized interconnection agreements and expedited interconnection to networks.
- C – Adequate for interconnection, but systems incur higher fees and longer delays than necessary. Some systems will likely be precluded from interconnection because of remaining barriers in the interconnection rules.

- D – Poor interconnection procedures that leave in place needless barriers to interconnection. A few best practices possibly included, but many excluded. A significant number of systems will experience delays and high fees for interconnection, and a sizable percentage may be blocked because of these rules.
- F – Interconnection procedures include many barriers to interconnection. Few to no generators will experience expedited interconnection, and few to no state best practices are adopted. Many to most DG systems will be blocked from interconnecting because of the standards.
- N/A – No state-wide policy.

7.3 U.S. Net-metering policies

States also have jurisdiction over interconnection of net-metered generators. Under net-metering, the utility bills the customer for the net energy consumed during the billing period – the difference between the energy the customer consumes and the energy produced by an eligible generating system at the customer's site or, if allowed, at another customer-designated site.

Net metering was pioneered in the U.S. as a way to allow solar and wind to provide electricity whenever available and allow use of that electricity whenever it was needed, beginning with utilities in Idaho in 1980, and in Arizona in 1981. In 1983, Minnesota passed the first state net metering law. The Energy Policy Act of 2005 required state electricity regulators to "consider" (but not necessarily implement) rules that mandate public electric utilities make available upon request net metering to their customers.

Several legislative bills have been proposed to institute a federal standard limit on net-metering. They range from H.R. 729, which sets a net metering cap at 2% of forecasted aggregate customer peak demand, to H.R. 1945 which has no aggregate cap, but does limit residential users to 10 kW, a low limit compared to many states, such as New Mexico, with an 80,000 kW limit, or states such as Arizona, Colorado, New Jersey, and Ohio which limit as a percentage of load (*Figure 7.9*). Arizona, California, Colorado, Connecticut, Delaware, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Utah, Vermont, and West Virginia are considered the most favorable states for net metering (they are the states to receive an "A" rating from *Freeing the Grid* in 2015 [35]).

The policy of net-metering has been especially effective in encouraging small-scale, renewable self-generation in the U.S. As of 2013, over 95 % of PV installations were net-metered, representing about half of the 11 GW of cumulative solar capacity in the U.S. Today 44 states, D.C. and four territories have adopted net-metering policies (*Figure 7.9*). While other state policies, such as feed-in tariffs or market based mechanisms, have similarly served to promote DG, net-metering has been the most widely adopted and utilised policy mechanisms in the U.S. to date. At the same time, because net-metering facilitates self-generation and thereby allows customers to reduce their overall energy consumption and thus their utility bills, it poses a particular challenge to the traditional utility paradigm. Namely, for utilities, the availability of net metering may be a concern from a revenue erosion or reliability perspective.

Almost all of the net-metering and interconnection procedures implemented at the state level are restricted to renewable energy and clean energy technologies. This includes solar, wind, biomass, landfill gas, small hydro, combined heat and power, municipal solid waste, anaerobic digestion, and ocean energy.

Many states have limited the total aggregate capacity eligible for net-metering, either state-wide or for specific utilities(utilities are concerned that customer-sited DG represents lost revenues). Of the 44 jurisdictions with net metering, 25 (57%) have some type of restriction on total eligible capacity, 16 (37%) have no restrictions, and 3 (7%) have notification or trigger policies (*Figure 7.10*). It must be noted, however, that capacity limits create regulatory uncertainty for customers considering net-metering.

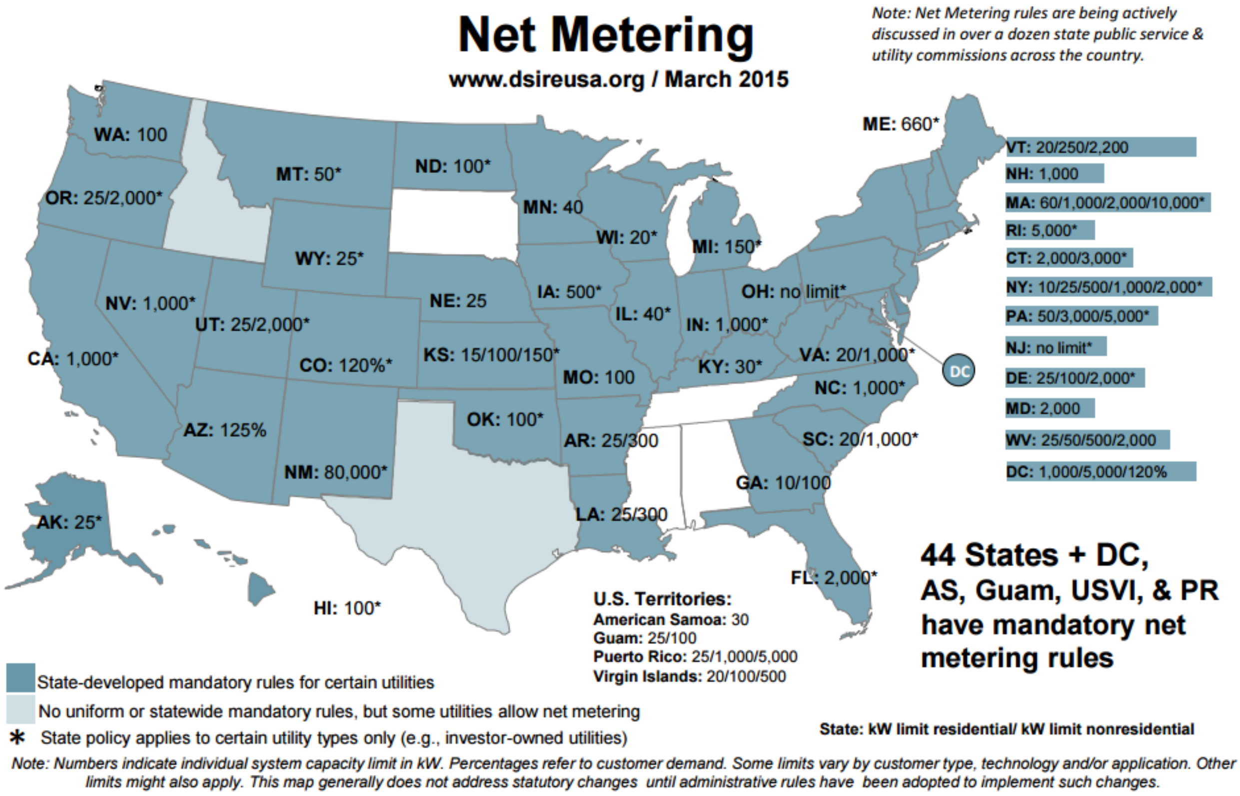


Figure 7.9 U.S. states net-metering policies– individual power limit (residential/commercial in kW) (source [36])

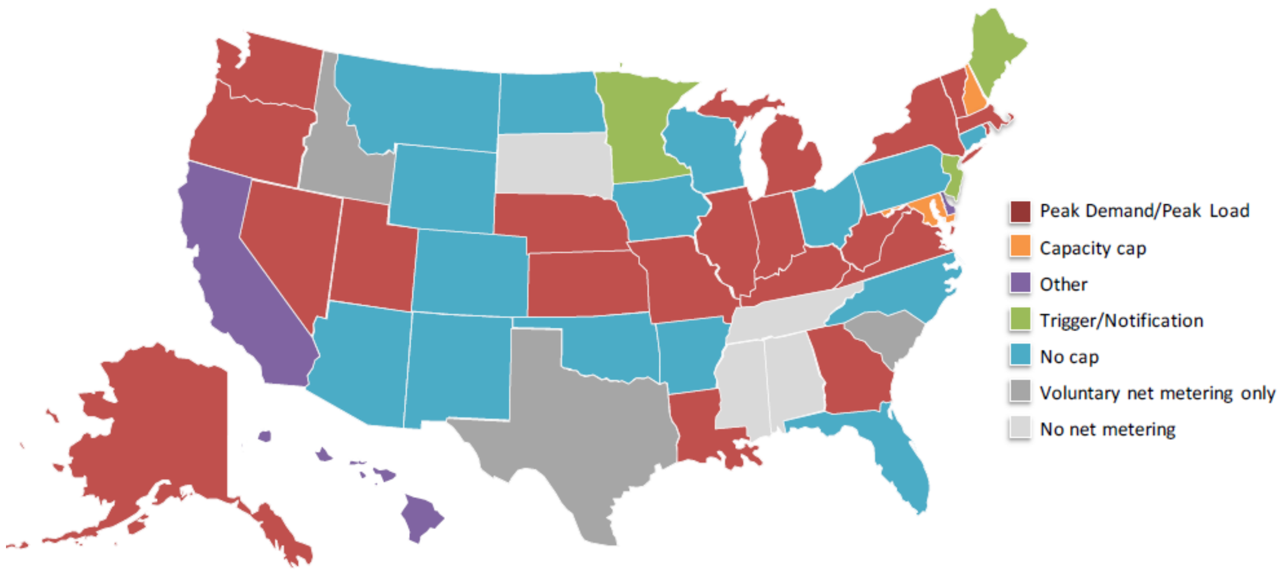


Figure 7.10 U.S. states net-metering program cap policies (source [39])

States have addressed net-metering program caps or triggers in the following ways:

- Percent of peak demand, capacity, or load. The most common program cap is based on a percentage of the utility or state's peak demand, capacity, or load in a given reference year (e.g. the previous year). Twenty states have a program cap of this nature. The percentage allowed under a peak demand cap is 0,2%–9%, with two notable exceptions: Vermont's cap was recently raised to 15% and Rocky Mountain Power in Utah has a cap of 20%.

- Megawatt (MW) cap. Some states have established caps at a fixed number of MW. Maryland caps net metering at 1500 MW and New Hampshire caps net metering at 50 MW.
- Percent of non-coincident customer peak demand or aggregated customer monthly demand. Non-coincident peak demand is the sum of individual customer peak demands, used by California. Delaware uses "aggregated customer monthly demand," though the exact definition has not been specified.
- Trigger mechanism. Three states (Maine, Minnesota, and New Jersey) have implemented trigger mechanisms, rather than binding caps. Maine and New Jersey base their trigger mechanisms on a percentage of peak demand, while Minnesota bases the trigger on a percentage of retail sales.

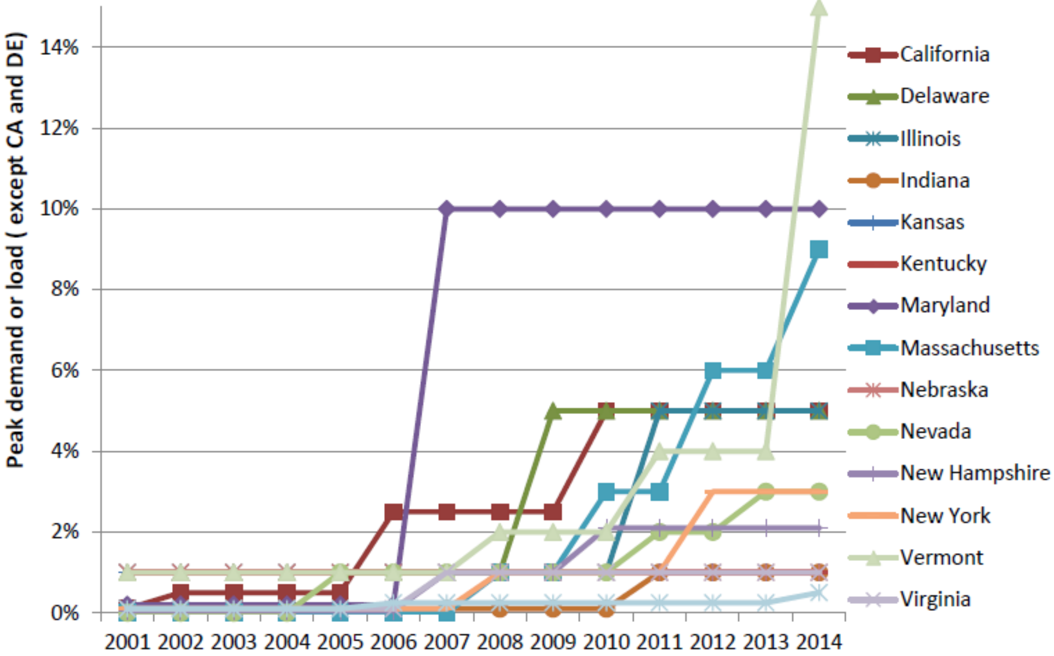


Figure 7.11 Major revisions to net metering program caps in the U.S., 2001–2014 (source [39])

Many PUCs and state legislatures have modified net metering program caps over time. In the early 2000s, program caps were generally at 1 % or less of peak demand, while today, a much wider range of program caps exist, with a number of caps at 5 % of peak demand or more (*Figure 7.11*). Although states define program caps in numerous ways, *Figure 7.11* shows that caps, once instituted, have always increased over time. In addition, a number of states that had policies initially without caps have instituted them over time.

7.4 U.S. review of selected states interconnection procedures

In the following sections, review of DG interconnection practices is given for several best graded U.S. States, including both interconnection procedures and net-metering. Texas have been added as American Electric Power operates in this state, although by [35] this state has received "D" grade for interconnection rules. Further details can be found on a very comprehensive DSIRE web site www.dsireusa.org and in [33].

7.4.1 Texas

In Texas the Distributed Generation Interconnection Manual [29] is applied for the DG interconnection to the network. In its interconnection manual the Public Utility Commission of Texas (PUCT) uses the following definition of distributed generation:

> *On-Site Distributed Generation (or Distributed Generation) — An electrical generating facility located at a customer's point of delivery (point of common coupling) of 10 MW or less and connected at a voltage less than 60 kV, which may be connected in parallel operation to the utility system. May include energy storage technologies as well as conventional generation technologies.*

The manual describes in depth the requirements, the assessment of the impact of DG on the network and the criteria that are used in order for the DSO to approve an interconnection with or without both study fee and new connection works.

Utility processing of DG applications

Upon receipt of a completed application, the transmission and distribution utility (TDU) has a defined period (4 to 6 weeks) of time in which to process the application and provide the following:

- approval to interconnect,
- approval to interconnect with a list of prescribed changes to the DG design,
- justification and cost estimate for prescribed changes to TDU system,
- application rejection with justification.

The Public Utility Commission of Texas (PUCT) limits when and why a TDU may charge the applicant for the performance of a service, coordination, or system impact study. In general, any study performed by the TDU shall follow these rules:

- study scope shall be based on characteristics of the DG at the proposed location,
- study shall consider cost incurred and benefits realized as a result of DG interconnection,
- TDU shall provide a cost estimate to the DG applicant prior to initiation of study,
- TDU shall make written reports and study results available to the DG applicant,
- TDU may reject application for demonstrable reliability or safety issues but must work to resolve those issues,
- TDU shall advise the DG applicant of potential secondary network-related problems before charging a study fee,
- TDU shall use best reasonable efforts to meet the application processing schedule, or will notify the DG applicant in writing why it cannot meet the schedule and provide estimated dates for application processing and interconnection.

If the proposed site is not on a networked secondary (i.e. LV network), no study fee may be charged to the applicant if all of the following apply:

- proposed DG equipment is pre-certified,
- proposed DG capacity is 500 kW or less,
- proposed DG is designed to export no more than 15 % of the total load on feeder (based on the most recent peak load demand),
- proposed DG will contribute not more than 25 % of the maximum potential short circuit current of the feeder.

A flow chart of this case is shown on the *Figure 7.12*.

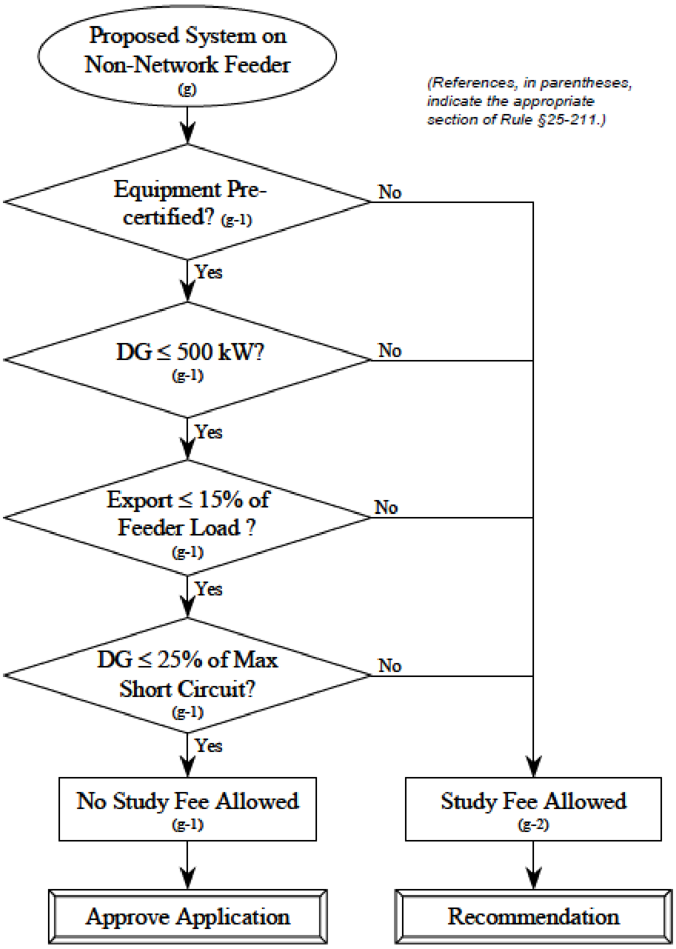


Figure 7.12 Flow chart of interconnection process (Texas) - non-network study chart (source [29])

Certain aspects of secondary network systems create technical difficulties that may make interconnection more costly to implement. In a network secondary distribution system, service is redundantly provided through multiple transformers as opposed to radial systems where there is only one path for power to flow from the distribution substation to a particular load. The secondaries of networked transformers are connected together to provide multiple potential paths for power and thus much higher reliability than an equivalent radial feeder. To keep power from inappropriately feeding from one transformer back through another transformer (feeding a fault on the primary side, for example), network protectors are used to detect such a back feed and open very quickly (within a few cycles).

If the proposed site is serviced by a networked secondary, no study fee may be charged to the applicant if:

- proposed DG equipment is pre-certified
- aggregate DG, including the proposed system, represents 25 % or less of the total load on the network (based on the most recent peak load demand),

and either:

- proposed DG has inverter-based protective functions, or
- proposed DG rating is less than the local applicant's verifiable minimum load.

A flow chart of this case is shown on the *Figure 7.13*.

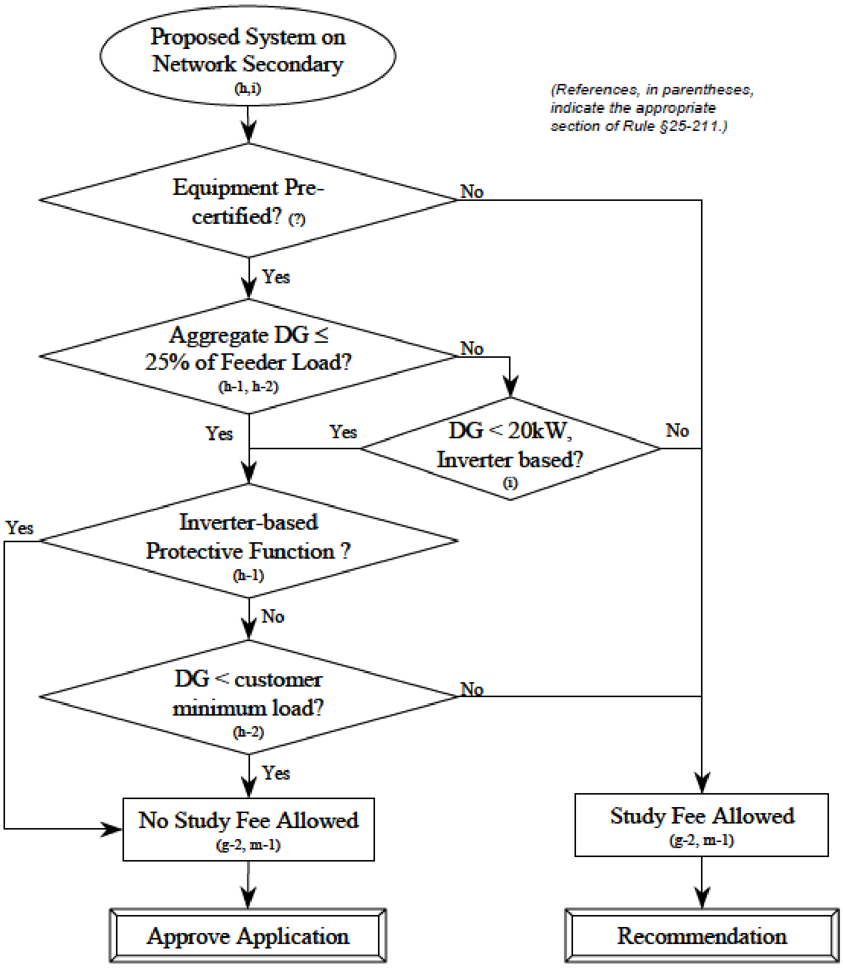


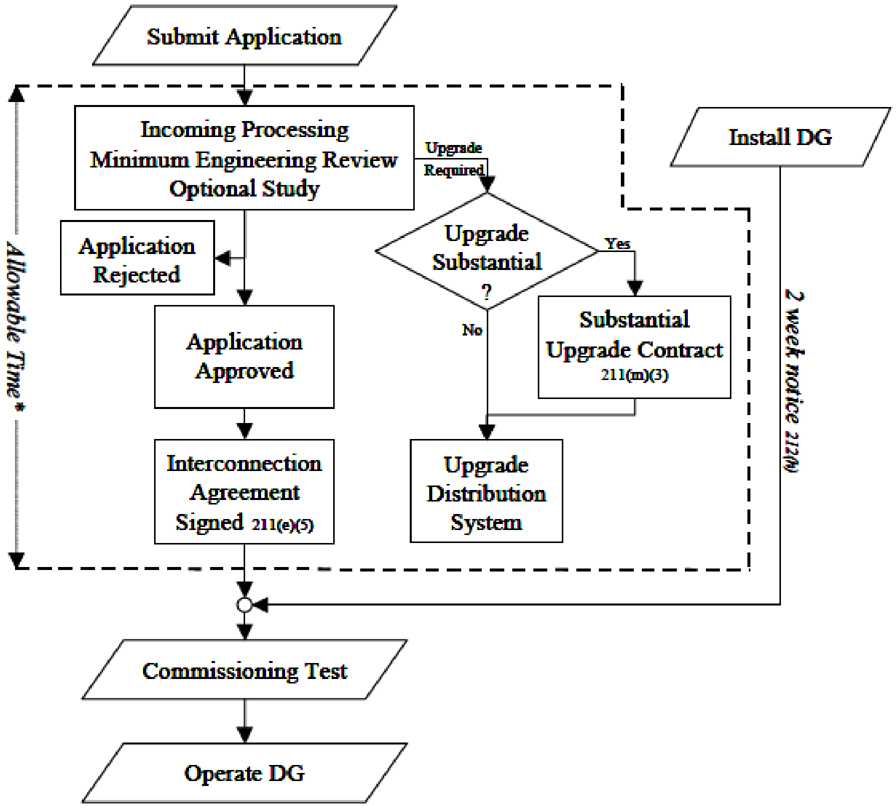
Figure 7.13 Flow chart of interconnection process (Texas) – network secondary study chart (source [29])

Otherwise, the TDU may charge the DG applicant a fee to offset the costs of the interconnection study. The TDU must advise applicants requesting DG interconnection on secondary networks about the potential problems and costs before initiating the study. Note that these provisions do not preclude the TDU from performing a study; they simply regulate when the TDU can charge the applicant for the cost of the study. Whether or not a study fee is billable to the applicant, the TDU may reject an application for demonstrable reliability or safety issues but must work to resolve those issues to the mutual satisfaction of the TDU and applicant. The TDU must make reasonable efforts to interconnect all proposed DG, including the possibility of switching network-secondary service to a radial feed if practical and if acceptable to the applicant.

The flow charts in *Figure 7.12* and *Figure 7.13* show, for non-network and secondary network systems respectively, how the Rule §25.211 requirements interact and what the TDU must consider when processing a DG interconnection application. Some of the decisions are based on location-specific information not available to the DG applicant at the time of application. It is important that the application be accurate and complete to eliminate delays in processing. These decision paths result in either “Approve Application” or “Recommendation”.

Systems meeting the requirements that result in “Approve Application” are considered simple with little chance of being a hazard to the distribution system, personnel, or neighbouring customers. These systems should not require any additional studies, thus the utility is not allowed to charge a study fee. The “Recommendation” results from a study that may be charged to the applicant, and may be one of the following:

- approval of the application as is,
- description of changes to the proposed DG system or to the distribution system necessary to approve the application, or
- rejection of the application due to specified reasons.



* -- Allowable Time from receipt of completed application to a signed interconnection agreement:

1) Systems using Precertified equipment – 4 weeks (§25.211(m)(1))
2) Systems using Non-precertified equipment – 6 weeks (§25.211(m)(2))
3) Add up to 6 weeks for additional interconnection study time for applications in Network secondaries where the aggregate DG exceeds 25% of the feeder load. (§25.211(h)(3))
4) If the proposed system will require substantial capital upgrades to the utility system, the utility shall provide the applicant an estimate of the schedule and applicant's cost, if any, for the upgrade. If the applicant desires to proceed with the upgrade, the applicant and the utility will enter into a contract for the completion of the upgrade. The commissioning test will be allowed within two weeks following the completion of such upgrades. (§25.211(m)(3)).
5) The TDU shall use best reasonable efforts to interconnect facilities within the time frames described above. If in a particular instance, the TDU determines that it cannot interconnect a facility within these time frames, it will notify the applicant in writing. The notification will identify the reason or reasons interconnection could not be performed in accordance with the schedule and provide an estimated date for interconnection (§25.211(m)(4)).

Figure 7.14 Application processing activities (source [29])

Figure 7.14 provides a timeline of activities, based primarily on the requirements in the Rule §25.211(m). Normally, it is anticipated that the application will be submitted, processed, and an interconnection agreement signed before construction activities begin. However, the Rules do not require this sequence and a more compressed schedule is possible.

Rule §25.212(h) requires the DG applicant to provide the utility with two-week notice prior to start-up testing. However the Rules do not specify when this must occur or which events must precede the notice. An applicant can anticipate approval, submit the two weeks' notice along with the application and be prepared for start-up testing immediately upon signing the interconnection agreement. If utility system modifications are required that are not considered a substantial capital upgrade, the utility may have to complete those upgrades prior to the start-up test. If the utility is unable to complete the modifications prior to commissioning (for example, if the two week notice is given with the application), they may work out partial operation or other arrangements with the applicant until such modifications can be completed. Rule §25.211(m)(4) allows the utility extra time to interconnect the DG if it can show suitable reasons for needing an extension to the time allowed.

DG interconnection requirements review

The DG applicant should provide all necessary information with the application, including documentation verifying compliance with the technical requirements of Rule §25.212. Failure to supply all necessary information is grounds for rejection of the application.

Table 7.1 DG Interconnection requirements (source [29])

	Closed Trans-ition	Single-Phase	Three-Phase			
	Capacity					
Feature	≤10 MW	≤50 kW	≤10 kW	10 kW - 500 kW	500 kW - 2 MW	2 MW - 10 MW
PUCT Rule Reference	§25.212-(g)	§25.212(d)	§25.212(e)-(3)(A)	§25.212(e)(3)-(B)	§25.212(e)-(3)(C)	§25.212-(e)(3)(D)
Interrupting devices (capable of interrupting maximum available fault current)	✓	✓	✓	✓	✓	[4]
Interconnection disconnect device (manual, lockable, visible, accessible)	✓	✓	✓	✓	✓	✓
Generator disconnect device	✓	✓	✓	✓	✓	✓
Over-voltage trip	✓	✓	✓	✓	✓	✓
Under-voltage trip	✓	✓	✓	✓	✓	✓
Over/Under frequency trip	✓	✓	✓	✓	✓	✓
Synchronizing check (A: Automatic, M: Manual)	A	A/M [1]	A/M [1]	A/M [1]	A [1]	A [1]
Ground over-voltage or over-current trip	[2]			[2]	[2]	[2]
Reverse power sensing				[3]	[3]	[3]
If exporting, power direction function may be used to block or delay under frequency trip					✓	✓
Automatic voltage regulator						[1]
Telemetry/transfer trip						✓

Notes:
✓ – Required feature (blank = not required)
[1] – Required for facilities with stand-alone capability
[2] – May be required by TDU; selection based on grounding system
[3] – Required, unless generator is less than applicant minimum load, to verify non-export
[4] – Systems exporting shall have either redundant or listed devices

The following information must be supplied for the application package to be viewed as complete:

- DG generator or inverter nameplate capacity in kW ($DG_{Capacity}$),
- maximum DG capacity allocated for export in kW (DG_{Export}),
- DG output (voltage, single-phase or three-phase),
- DG type (e.g. inverter-based, synchronous, induction),
- DG short circuit capability (DG_{SCmax}),

- whether the DG facility meets the Texas pre-certification requirements (see Section 7 of [29]),
- location of DG (street address, applicant account number),
- minimum load of the facility to which the DG is connected,
- documentation that the DG facility contains all the minimum protective functions required in Rule §25.212 (see *Table 7.1*).
- documentation that the appropriate protective functions are either factory pre-set to proper values or are capable of being set according to the parameters set forth in Rule §25.212 (see *Table 7.2*).

Table 7.2 DG Voltage/Frequency Disturbance Delay & Trip Times (source [29])

Range		**Trip Time[2]**	
Percentage	Voltage[1]	Seconds	Cycles
<70%	<84	0.166	10 (Delay) & 10 (Trip)
70%-90%	84 – 108	30.0 & 0.166	1800 (Delay) & 10 (Trip)
90% - 105%	108 – 126	Normal Operating Range	
105% - 110%	126 – 132	30.0 & 0.166	1800 (Delay) & 10 (Trip)
>110%	>132	0.166	10 (Delay) & 10 (Trip)
	Frequency (Hz)		
	<59.3	0.25	15 (Trip)
	59.3 – 60.5	Normal Operating Range	
	>60.5	0.25	15 (Trip)

[1] Voltage shown based on 120V, nominal.

[2] Trip times for voltage excursions were added for completeness by the PUCT Project No. 22318 Pre-certification Working Group as the intent of 25.212.

Once the application package is complete, the TDU should determine whether the proposed DG installation site is on a secondary network by locating the proposed facility on its distribution circuit. The answer to this question will impact the type of review process and study fees and schedules associated with the application.

Non-Network Review (Figure 7.12)

If the DG capacity is less than or equal to 500 kW, the review can continue to the export level review. If the DG capacity, as reported on the completed application, exceeds the 500 kW threshold, the TDU is allowed up to four weeks to perform a study that may involve a fee.

A key question for each DG installation is whether the DG applicant intends to export generation across the point of common coupling (PCC); and if so, how much. If power is to be exported across the PCC:

- DG that exports can cause reverse voltage drops (from the DG towards the substation). Thus, the TDU may need to study the local distribution system and determine if adjustments to local voltage regulation schemes are necessary,
- protection against the formation of unintended islands becomes more complicated since the DG will be supporting load beyond the PCC.

Rule §25.211 (g)(1) provides a threshold to address these concerns, stated as 15 % of the total load on a single radial feeder. Here again, total load is defined as the maximum load over the previous 12–month period. This threshold, expressed in equation form, is the following:

$$DG_{\text{export max}} \leq 0.15 \times FeederLoad_{\max}$$

This is the value at or below which the DG can export without requiring costly changes to the TDU system in order to accommodate the DG export. If the system falls within the export limit, it is assumed that the application of the DG on that portion of the distribution system will not cause the complications listed above.

DG which exceeds this threshold may be studied to determine whether it could cause islanding or adverse power flows.

If the DG passes the export level threshold of 15 % of feeder load, the maximum short circuit current on the radial feeder must be calculated. The TDU will then calculate the maximum short circuit current contribution at the DG location. Once this value is determined, multiply that quantity by 0,25 to establish the 25 % threshold for the primary feeder. The DG's maximum short circuit capability found in the application must then be converted to the corresponding short circuit current after transforming to primary voltage. This transformed DG short circuit must be less than or equal to the 25 % threshold. This threshold is expressed through the following equations:

Assume: $FeederShortCircuit_{max} = FSC_{max}$

and: $DG_{ShortCircuitmax} = MaxDG_{ShortCircuit} \times DG_{OutputVoltage} \div PrimaryVoltage = DG_{SCmax}$

To comply with this threshold, DG_{SCmax} must be less than or equal to 25 % of FSC_{max}:

$$DG_{SCmax} \leq 0{,}25 \times FSCmax$$

If the DG complies with this threshold, it is assumed that:

- the DG has little impact on the distribution system's short circuit duty,
- the DG will not adversely affect the fault detection sensitivity of the distribution system,
- the utility's relay coordination and fuse-saving schemes are not significantly impacted.

If the DG does not comply with this threshold, the TDU may study the DG application over four weeks with a study fee. If the DG passes all these thresholds, it will not require changes to the utility system to accommodate the installation. Such DG will not require additional studies or equipment to accommodate, and can interconnect without any study fees.

Network secondary review (Figure 7.13)

If the aggregate DG output within a networked secondary exceeds the aggregate load, the excess power will activate one or more network protectors. If such a situation were allowed, the reliability of the secondary network would be reduced. In such a circumstance, DG could compromise grid reliability. Most downtown areas of larger cities have secondary networks (e.g. Austin, Dallas, Houston and San Antonio). How far those networks extend and where the network ends and radial distribution begins is a function of the density of the load and a number of other factors. Facilities in the center of downtown areas are very likely to be on networks, whereas facilities in suburban and rural areas are almost certain to be on a radial distribution system.

Secondary networks are used where load is sufficiently dense to justify the added reliability and added cost of such a system. As a result, the DG facility (or aggregate DG) could be sizeable before the utility engineer needs to be concerned. For example, 1 MW of DG on a 10 MW network would be of little concern. Conversely, 1 MW of DG on a 3 MW network could be of significant concern.

Rule §25.211(h)(1) and (2) define when the TDU shall approve applications for interconnection (the TDU may elect to do a study but may not charge a fee). These are as follows:

- §25.211(h)(1): DG facilities that use inverter-based protective functions with total distributed generation (including the new facility) on the affected secondary network representing no more than 25 % of the total load of that network.

- §25.211(h)(2): Other on-site generation facilities whose total generation is less than the local customer's load (non-export) and with total distributed generation (including the new facility) on affected secondary network representing no more than 25 % of the total load of that network.

The aggregate DG is determined by summing the nameplate ratings of each of the DG units within the network. The total load of the network is defined as the maximum load of the network for the previous 12-month period. This threshold, expressed in equation form, is the following:

$$TotalDGCapacitynetwork = TDGCnetwork \leq 0{,}25 \times TotalLoad$$

This is the value at or below which inverter-based DG should not require costly changes to the utility system in order to accommodate the DG installation. The TDU shall accept applications, and a study fee may not be charged since it is assumed that no study is necessary. It is assumed that all inverter-based DG under 20 kW is so small that, irrespective of the 25 % threshold, no study is necessary and therefore the application shall be accepted and no study fee may be charged.

To determine whether or not a DG complies with §25.211(h)(2) above, it must be determined whether the DG will export power. No export limit was provided for network systems, meaning that all export systems on network secondaries may be subject to a study for which a fee may be charged (excluding inverter-based systems).

A DG system designed for non-export (i.e. it only offsets applicant load without feeding into the grid) simplifies the review process. Non-export systems will not adversely impact the secondary network protection schemes and, for systems with explicit non-export capabilities, the need for additional islanding detection is eliminated. There are three methods to ensure that power is not exported:

1) (Implicit) To ensure no export of power without the use of explicit non-export protective functions, the capacity of the DG must be no greater than the customer's verifiable minimum annual load. Use of additional anti-islanding functions may be required to ensure worker and equipment safety.
2) (Explicit) To ensure power is never exported, a reverse power protective function must be implemented within the facility. Default setting shall be 0,1% (export) of transformer rating, with a maximum two-second time delay.
3) (Explicit) To ensure at least a minimum import of power, an under-power protective function may be implemented within the facility. Default setting shall be 5 % (import) of DG gross nameplate rating, with maximum two-second time delay.

Non-inverter-based DG that does not export and meets the 25 % threshold should not require changes to the utility system in order to accommodate the installation. The serving utility shall accept these applications, and a study fee may not be charged since it is pre-assumed that no study is necessary. Although the sections of the Rules addressing studies do not specifically provide options for non-export other than (1) above, options (2) and (3) are technically equivalent to (1) and do not require a study fee.

If the DG is not inverter-based and is not less than minimum applicant load, but still complies with the 25 % threshold, a study fee may be charged to the applicant to determine whether any modifications need to be made. The study can take up to four weeks.

If the total DG capacity on a particular network exceeds 25 % of the total load of the network, the TDU may halt the application process up to six weeks while performing a study that may involve a study fee. Such an analysis may require detailed dynamic modelling of the load/DG/network interaction. Depending on such issues as load diversity and generator dispatch, the utility may determine that some DG beyond the 25 % limit may be acceptable while others may be unacceptable. As such modelling can be quite costly, the utility must inform the DG applicant of the potential issues and appropriate study cost before initiating the study. Once the study is complete, the application processing and the allowable processing time (see *Figure 7.14*) shall continue.

Conditions when service needs to be converted to radial

As the total DG on a secondary network grows relative to total network load, so does the likelihood of reverse power flow through one or more network protectors causing them to open and interrupt service. In this case, power flow studies may be needed to determine if it is possible for the network protectors to see reverse power (even momentarily) from the DG and initiate a trip.

If the power flow study determines that the DG installation could cause unintended operation of the network protector, one way to mitigate this problem is to switch the DG facility service to a radial service. If the proposed DG location is close to a network protector, it might be easy to switch the DG onto a radial feeder, making the change less costly. If the 25 % of network load requirement is not met, the utility should conduct a power flow study and investigate whether it is necessary to convert the DG service from network to radial to mitigate the unintended operation of the network protectors.

For most electric customers throughout the Texas, net metering as the term is traditionally defined, remains unavailable (*Figure 7.9*).

7.4.2 Ohio

In November 2012, the Public Utilities Commission of Ohio (PUCO) opened a docket (Case 12-2051-EL-RDR, [34]) to review interconnection rules for investor-owned utilities. The PUCO adopted amended rules for electric generator interconnection service and standards, in accordance with the State of Ohio's 5-year rule review procedures, which became effective on July 10, 2014.

Ohio's interconnection standards provide for three levels of review for the interconnection of DG systems up to 20 MW in capacity.

All applicants are eligible but not required to request pre-application report that provides site-specific information. Interested applicants can choose to obtain this pre-application report at a cost (request procedure, timeline and cost are detailed in Chapter 4901:1-22-04(B)(2) Interconnection Services in the Ohio Administrative Code (OAC)).

Table 7.3 illustrates major Ohio application requirements for DG interconnection, based on Chapter 4901:1-22 Interconnection Services in the OAC.

- Level 1 simplified review procedure allows eligible inverter-based distributed generators to have their interconnection request reviewed within 15 business days and a standard interconnection agreement within 5 business days of determination. Key eligibility requirements for this process include a nameplate capacity of 25 kW or less and meeting IEEE 1547 and UL 1741 standards. Additional, site-specific eligibility requirements and approval criteria are listed in the rules (4901:1-22-06).
- Level 2 interconnection has expedited and supplemental review procedures that applies to certified, inverter-based or synchronous systems up to 5 MW in capacity. Specific capacity limits vary depending upon criteria at the proposed point of interconnection. These systems must meet IEEE 1547 and UL 1741 standards and may not be interconnected at the transmission level. Technical screens, fees, capacity-limit criteria, and timelines are detailed in the rules (4901:1-22-07). Approved applicants will receive a standard interconnection agreement.

  If the electric distribution utility determines that the applicant does not meet the approval criteria, the utility can:

  - allow the applicant to interconnect if all safety, reliability, and power quality standards can be satisfactorily met,
  - determine that further study or minor modifications must occur before the facility can meet requirements to interconnect to be carried out by either the applicant or the utility,
  - obtain the applicant's agreement to continue evaluating the application under Level 3 standard review,
  - begin a Level 2 supplemental review process described in detail in the rules (4901:1-22).
- Level 3 interconnection, the standard procedure, applies to inverter-based or synchronous systems up to 20 MW in capacity that do not qualify for Level 1 or Level 2 certification. Technical screens, fees and timelines are detailed in the rules (4901:1-22-08).

The interconnection forms specify two application forms for interconnection: a "short form" application for systems up to 25 kW in capacity and utilize equipment that is certified in compliance with IEEE 1547 and UL1741, and a standard application for systems that do not qualify for the "short form" application. The PUCO website also provides a checklist for applicants to determine whether to complete the "short form" or the standard form.

Each utility must provide applicants with a standard interconnection agreement following completion of project review, and must designate an employee or office to provide the applicant with information on the requirements for the utilities' application review process. Utilities may not require additional liability insurance beyond proof of insurance. The rules include a provision for alternative dispute resolution for non-residential and non-commercial customers, and for formal complaints brought by applicants and interconnected customers.

Table 7.3 Major Ohio application requirements for DG interconnection (source PUCO)

<table>
<tr><th>Review Level</th><th colspan="3">Eligibility</th><th>Application / Contract</th><th>Review</th><th>Application Fees</th><th>Timeframe</th></tr>
<tr><td rowspan="2">Pre-Application</td><td colspan="3" rowspan="2">any project</td><td>applicant's informal request / discussion of information specified in 4901:1-22-04 (B)(1)</td><td rowspan="2">Pre-Application Review</td><td>none</td><td>varies</td></tr>
<tr><td>applicant's formal written request
/
Pre-Application Report</td><td>$300
processing fee</td><td>within 10 business days of the EDU receiving the applicant's written request and fee payment</td></tr>
<tr><td>1</td><td colspan="3">» IEEE 1547 and UL 1741 compliance certified
» inverter-based systems ≤ 25 kW</td><td>Short Form Application / Standard Interconnection Agreement</td><td>Simplified Review</td><td>up to $50 and may be waived</td><td>within 15 business days of the EDU notifying the applicant that it has received a complete interconnection service application</td></tr>
<tr><td rowspan="6">2</td><td colspan="3">» IEEE 1547 and UL 1741 compliance certified
» systems that are ineligible for Level 1 Review
» system types not exceeding the limits identified below</td><td rowspan="6">Standard Application / Standard Interconnection Agreement</td><td rowspan="6">Expedited Review</td><td rowspan="6">up to $50, plus one dollar per kilowatt of system nameplate capacity</td><td rowspan="6">within 20 business days of the EDU notifying the applicant that it has received a complete Interconnection Service Application</td></tr>
<tr><td>Line Voltage</td><td>Expedited Review Regardless of Location</td><td>Expedited Review on line capacity ≥ 600 amp and distance < 2.5 feeder miles from substation</td></tr>
<tr><td>≤ 5kV</td><td>≤ 500 kW</td><td>< 2 MW</td></tr>
<tr><td>> 5kV & ≤ 15 kV</td><td>≤ 2MW</td><td>< 3 MW</td></tr>
<tr><td>> 15 kV & ≤ 30 kV</td><td>≤ 3MW</td><td>< 4 MW</td></tr>
<tr><td>> 30 kV & ≤ 69 kV</td><td>≤ 4MW</td><td>< 5 MW</td></tr>
<tr><td>2
Supplemental</td><td colspan="3">» systems reviewed under Level 2 and failed to meet the criteria but could possibly be interconnected consistent with safety, reliability, and power quality standards after minor modifications/further study</td><td>applicant's written agreement within 15 days of EDU's offer to perform Supplemental Review / Standard Interconnection Agreement</td><td>Expedited Review including customized studies based on technical screens</td><td>$2,500 deposit fee then adjusted to reflect actual costs of any engineering work done
+ actual cost of any minor modification of the EDU's system that would otherwise not be done but for the applicant's interconnection request</td><td>within 25 business days of the EDU receiving the Supplemental Review fee deposit</td></tr>
<tr><td>3</td><td colspan="3">» not IEEE 1547 and UL 1741 compliance certified
» all system types ≤ 20MW that are ineligible for/failed to pass Level 1 and Level 2 Review</td><td>Standard Application or applicant's agreement to continue evaluating the application that fails the Supplemental Review criteria /
Standard Interconnection Agreement</td><td>Standard Review including customized studies</td><td>up to $100, plus two dollars per kilowatt of system nameplate capacity
+ actual cost of engineering work done as part of any customized study
+ actual cost of any modification of the EDU's system that would otherwise not be done but for the applicant's interconnection request
- cost of Supplemental Review (if Level 3 evaluation is pursuant to Supplemental Review)</td><td>varies</td></tr>
</table>

7.4.3 California

California's interconnection standards are outlined in Rule 21, which uses a screening process to determine the level of review process required for interconnected systems. California's "Rule 21" generally applies to systems connecting to an investor-owned utility's distribution grid, non-export generating facilities connecting to an investor-owned utility's transmission grid and all net metered facilities in an investor-owned utility's service territory. Systems connecting to an investor-owned utility's distribution grid for the purpose of participating in a wholesale transaction must apply under the investor-owned utility's Wholesale Distribution Access Tariff. Systems connecting to the transmission grid must apply to the California Independent System Operator for interconnection. Systems connecting to the grid of a municipal or cooperative utility must follow the interconnection procedures adopted by that utility.

Rule 21 requirements apply only to distributed generation interconnected to distribution systems, and each of the three major utilities in California publishes its own version of Rule 21: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. These rules are identical across the three utilities, with minor exceptions, such as slightly different interconnection agreements. Each utility's rule was approved by the California Public Utilities Commission (CPUC). Several California municipal utilities have also adopted interconnection rules similar to Rule 21.

Rule 21 clearly defines a series of screens meant to filter applicants into the study path most suited for their project. It also establishes fixed timelines for the screens intended to speed the process of approval. Also defined in the tariff are a variety of fees and deposits required at various stages of the interconnection process. Net-metered facilities are exempt from most of these fees.

The "Initial Review Process" is performed after the customer applies for interconnection, and if the system qualifies for a simplified process, no additional studies are needed. *Figure 7.15* shows a simple screening process used in California to determine if an interconnection qualifies for the state's simplified interconnection process.

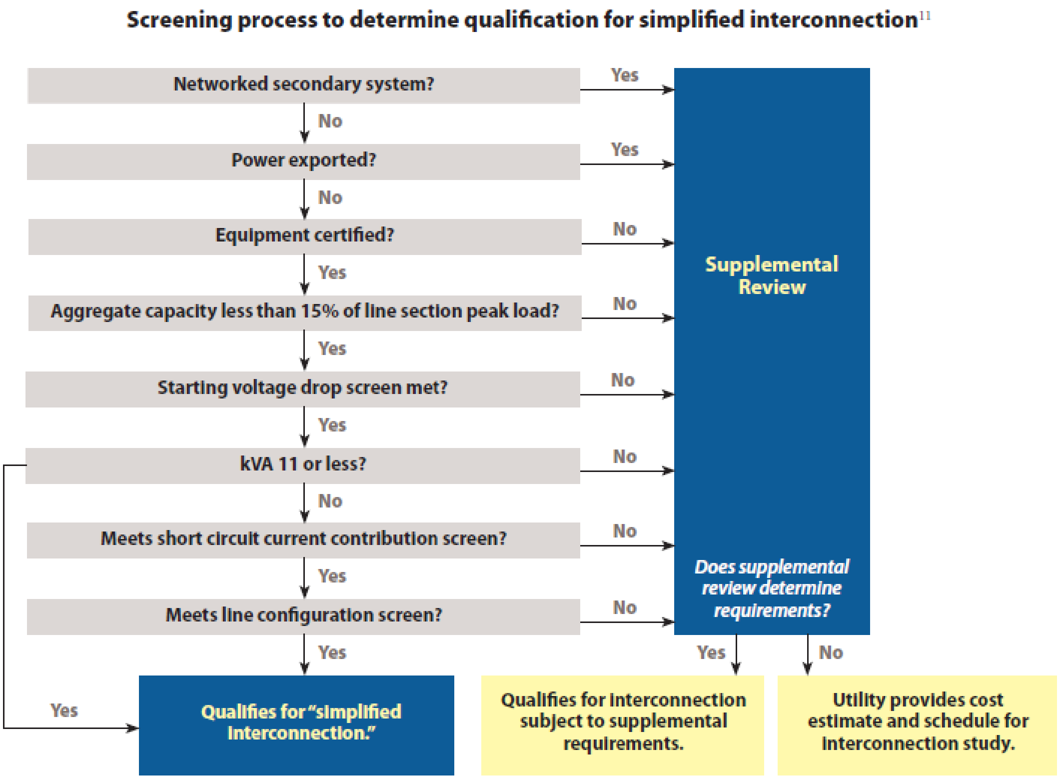


Figure 7.15 Screening process to determine qualification for simplified interconnection (source [33])

If the system does not pass the initial screening process, it goes through a “Supplemental Review Process”. After the supplemental process, systems may be permitted to connect to the grid through the simplified process, but with some additional requirements. If the proposed project fails one or more screens, the system is subjected to a full interconnection study, whose costs are determined by the utility and paid by the system owner.

Rule 21 has provisions for certified equipment that is eligible for an expedited review, but approved equipment to date is much smaller than 10 MW. Rule 21’s technical requirements for DG installations are similar to those established in IEEE Standard 1547.

7.4.4 Oregon

Oregon has three separate interconnection standards: one for net-metered systems, one for small generator facilities (non-net metered systems), and one for large generator facilities (non-net metered systems). Oregon has also established separate net-metering requirements and interconnection standards for the state's primary investor-owned utilities (PGE and PacifiCorp), and for its municipal utilities and electric cooperatives.

Interconnection for net-metered systems

PGE and PacifiCorp customers

The Oregon Public Utilities Commission (PUC) adopted new rules for net metering for PGE and PacifiCorp customers in July 2007 with Order 07-319, raising the individual system capacity limit from 25 kW to 2 MW for non-residential applications.

The limit on individual residential systems is 25 kW. Systems that generate electricity using solar power, wind power, hydropower, fuel cells or biomass resources are eligible. Net metered systems must be intended primarily to offset part or all of a customer’s requirements for electricity. Utilities may not limit the aggregate capacity of net metered systems.

The PUC rules include three levels of interconnection for net-metered systems, and require the use of a standard application, a standard agreement, and reasonable procedural timelines for utilities and applicants. Each utility must designate an employee or office from which an applicant can obtain basic application forms and information through an informal process. With the exception of certain inverter-based systems 25 kW or less, a manual, external disconnect switch is required. Utilities may not require customers to purchase additional liability insurance or to name the utility as an "additional insured" on the customer's liability policy.

Oregon's rules provide for three levels of interconnection review:

- Level 1: applies to certified, inverter-based systems up to 25 kW in capacity that comply with IEEE standards and UL 1741. A system is considered "certified" if it has been tested and listed by a nationally recognized testing lab. Systems must pass specific technical screens. Utilities may not charge application fees or other fees for Level 1 review.
- Level 2: applies to certified systems up to 2 MW that comply with IEEE standards and UL 1741, as applicable, but do not qualify for Level 1 review. A system is considered "certified" if it has been tested and listed by a nationally recognized testing lab. Systems must pass specific technical screens. Interconnection to area networks is permitted, with limitations. Utilities may charge fees of up to $50 plus $1 per kW of system capacity, plus "the reasonable cost of any required minor modifications to the electric distribution system or additional review." Costs for engineering work performed as part of an impact study or interconnection facilities study are limited to $100 per hour.
- Level 3: applies to systems that do not qualify for Level 1 review or Level 2 review. Systems must pass specific technical screens. Interconnection to area networks is permitted, with limitations. Utilities

may charge fees of up to $100 plus $2 per kW of system capacity, plus charges for time spent on any required impact or facilities studies. Costs for engineering work performed as part of an impact study or interconnection facilities study are limited to $100 per hour. If a utility must install facilities in order to accommodate the interconnection of a system, the applicant must pay for the costs of such facilities.

Customers of Municipal Utilities, Cooperatives and People's Utility Districts

Oregon's municipal utilities, electric cooperatives and people's utility districts must offer customers net metering pursuant to OR Revised Statutes 757.300. Systems that generate electricity using solar power, wind power, hydropower, fuel cells or biomass resources are eligible. Net-metered systems must be intended primarily to offset part or all of a customer’s requirements for electricity. The aggregated capacity of all net-metered systems is limited to 0,5% of a utility's historic single-hour peak load.

The Oregon Building Codes Division has developed interconnection guidelines for all utilities. Systems must be installed according to the Oregon Electric Specialty Code (essentially NEC Article 690) and relevant IEEE standards, and must employ UL-listed equipment. A manual external disconnect switch is not required in the guidelines, but some utilities require this switch in their tariffs. Additional liability insurance is not required. Utilities are exempt from any liability for loss, injury or death related to the interconnection of a net-metered system.

Interconnection for Small Generator Facilities

In June 2009, the PUC issued Order No. 09-196 and adopted administrative rules for the interconnection of small generator facilities up to 10 MW. These rules were finalized in September 2009, when the PUC approved changes made to the three investor-owned utilities’ interconnection forms and agreements. While Idaho Power is not subject to the interconnection standards for net-metered systems, it is subject to these interconnection standards.

There are four tiers of review for small generating facilities, based on system capacity: 25 kW, 2 MW, non-exporting systems up to 10 MW, and other systems. Application fees are differentiated, based on tier. The maximum application fee is $100 for Tier 1, $500 for Tier 2, and $1000 for Tiers 3 and 4. There may be additional costs if an evaluation is required, but the applicant must agree to this cost prior to the evaluation being conducted. The rules for the first two tiers mirror the interconnection standards for net-metered systems.

Interconnection for Large Generator Facilities

In April 2010, the PUC issued Order No. 10-132 for the interconnection of large generator facilities, defined as systems larger than 20 MW. The PUC approved interconnection procedures and a standard interconnection agreement based on FERC's Large Generator Interconnection Procedures and Large Generator Interconnection Agreement (see section 7.2.2).

7.4.5 Massachusetts

Massachusetts' interconnection standards apply to all forms of DG, including renewables, and to all customers of the state's three investor-owned utilities (Unitil, Eversource, and National Grid). Massachusetts requires investor-owned utilities to have standard interconnection tariffs.

There are three basic paths for interconnection in the state (*Table 7.4*):

- the “Simplified**”** interconnection process applies to IEE 1547.1-certified, inverter-based facilities with:
    - a power rating of 15 kW or less for single-phase systems located on a radial distribution circuit,

    - a power rating of 25 kW or less for three-phase systems located on a radial distribution circuit (where the facility capacity is less than 15 % of the feeder/circuit annual peak load, and if available, line segment),
    - a power rating of less than 1/15 of the customer's minimum load and located on a spot network, or
    - a power rating of less than 1/15 of the customer's minimum load and 15 kW or less and located on an area network,
- the "Expedited" interconnection process applies to:
    - inverter-based facilities 15 kW or greater for single-phase systems,
    - inverter-based facilities 25 kW or greater for 3-phase systems,
    - other systems of all sizes that are served by radial systems and meet certain other requirements.
- the "Standard**"** process is for all other facilities that do not meet the specifications of the "Simplified" or "Expedited" process, including systems on all networks.

The issue of interconnection to network systems is particularly important in Massachusetts because network systems are commonly used in dense urban areas, such as Boston. Order 11-75-E implemented a more transparent "Supplemental Review" screen process for projects that fail the initial "Simplified" and "Expedited" screens. If a project fails the "Simplified" and "Expedited" screens, it must pass three supplemental review screens, otherwise it must go through the full "Standard" review process.

Table 7.4 Interconnection project review paths in Massachusetts (source)

	Simplified	Expedited	Standard
Project type	PV and other inverter-based technologies served by radial systems, 15 kW or less 1-Phase or up to 25 kW 3-Phase [Note: Simplified Spot Network path is 30-90 days]	Inverter-based systems greater than 15 kW 1-Phase or greater than 25 kW 3-Phase and other systems of all sizes that are served by radial systems and meet other requirements	All projects not eligible for simplified or expedited review, including all systems on networks
Typical projects	Small PV, demonstrations or homeowner wind	Certified large renewables, cogeneration, and other turbine or engines of any size	Uncertified large projects, unusually complex projects, or projects of any size located on networks
Total maximum days*	Keep standard maximum at 15 days. However, add additional 5 days for projects that fail Screen #5 (must be single-phase or all 3-phase)*	40 – 60*	125-150* If sub-station modifications are needed, add 20 days* If necessary system modifications are likely to cost over $200,000 in EPS upgrades, add 45 days*

Massachusetts uses a 100 % of minimum load penetration screen in the "Supplemental Review" process. If the generating capacity is less than 100 % of minimum load, it may not require a detailed study. In addition to these different paths, for all systems 500 kW or greater, facility owners must request and receive a pre-application report from the utility. The pre-application report is optional for facilities less than 500 kW; no fee is charged for this report.

For the "Simplified" and "Expedited" interconnection paths, technical requirements are based on the IEEE 1547 and UL 1741 standards. A manual external disconnect switch may be required at the discretion of the utility (project-specific, not required in the tariffs).

Utilities must collect and track information on the interconnection process. This information is used in revising and updating the standards. Massachusetts utilities provide monthly reporting on the status of all interconnection applications submitted since January 2009 that follow the "Expedited" or "Standard" review process.

Starting December 2014 DOER added new interactive charts on utility performance and enforcement (available on Massachusetts Department of Energy Resources (DOER) web site [40]). The charts below provide an overview of the type and quantity of distributed generation projects that have entered or completed the interconnection process. *Figure 7.16* shows the change in the total number of interconnection applications received (red line), interconnection applications deemed complete (blue line), interconnection agreements sent (orange line), and projects authorized to connect (green line), over time. Graph does not include those applications that follow the "Simplified" review process for smaller systems.

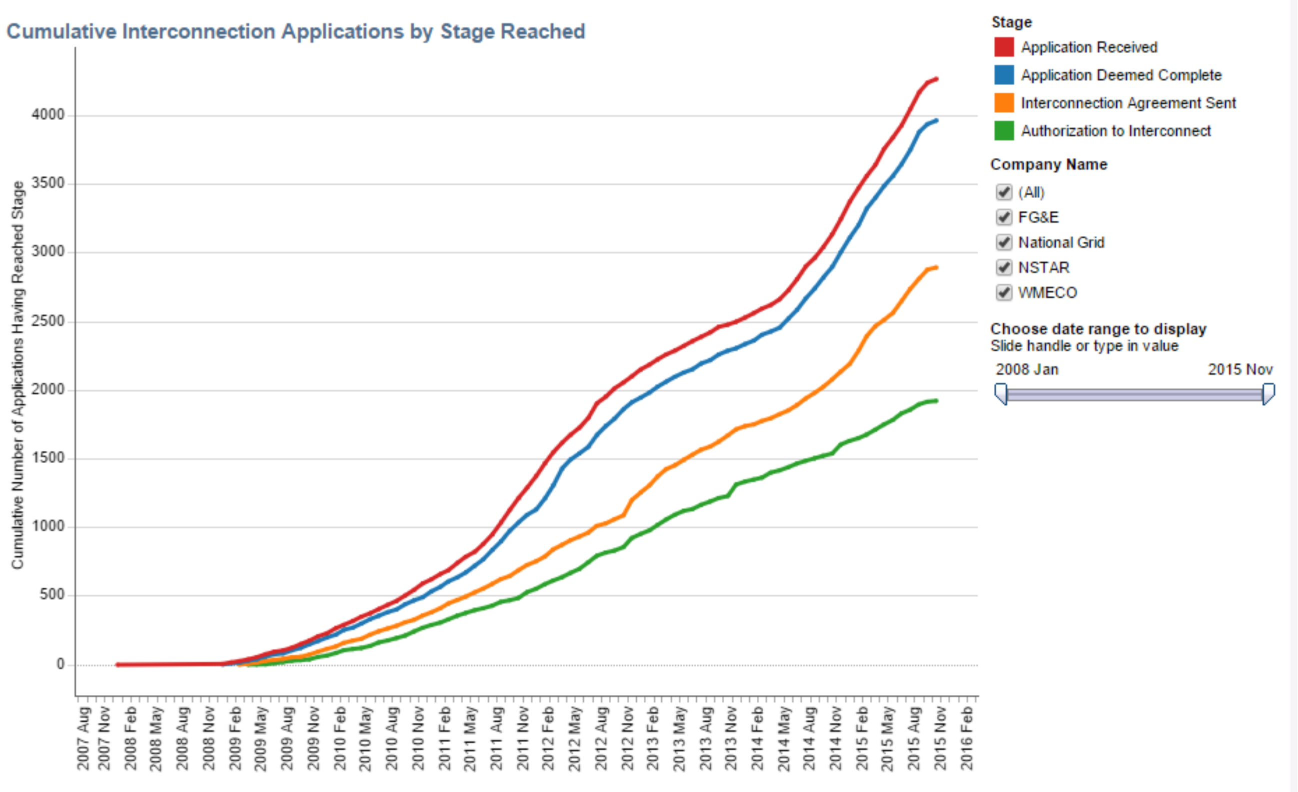


Figure 7.16 Publically available data on cumulative interconnection applications by stage reached in Massachusetts (source [40])

The chart on *Figure 7.17* helps answer the question "How long does the interconnection application process take for a project in Massachusetts?". This chart shows only the amount of time from the date when an interconnection application was deemed complete to the date the interconnection agreement was sent. The other phases are not depicted in this chart. Graph does not include those applications that follow the "Simplified" review process for smaller systems.

The charts on *Figure 7.18* help answer the question: "On average how are utilities performing with regard to interconnecting three project types in Massachusetts?". The average time lapsed is accounted for by dividing the total utility work time lapsed by the total number of projects by each utility and compared against the utility time allowed. This interactive analysis is updated monthly and is usually available within 30 days after the end of a reporting period.

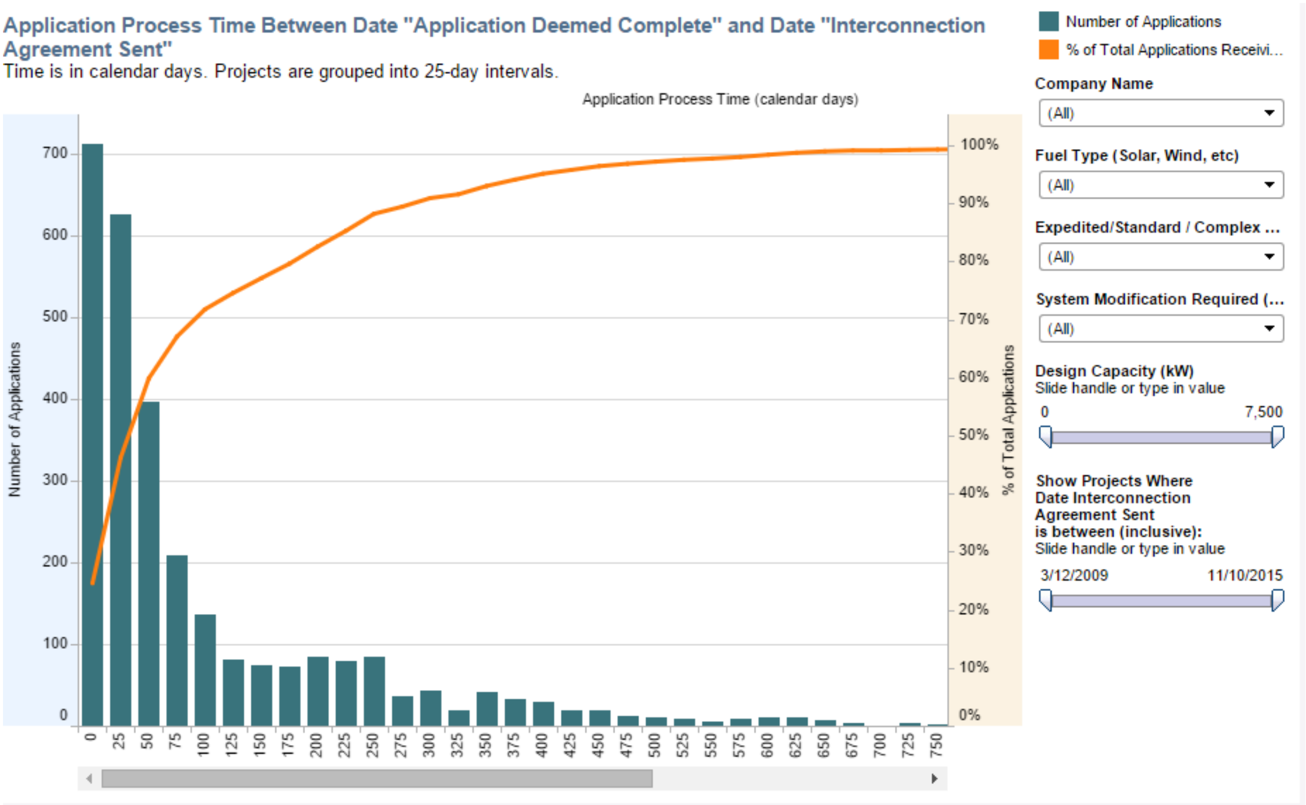
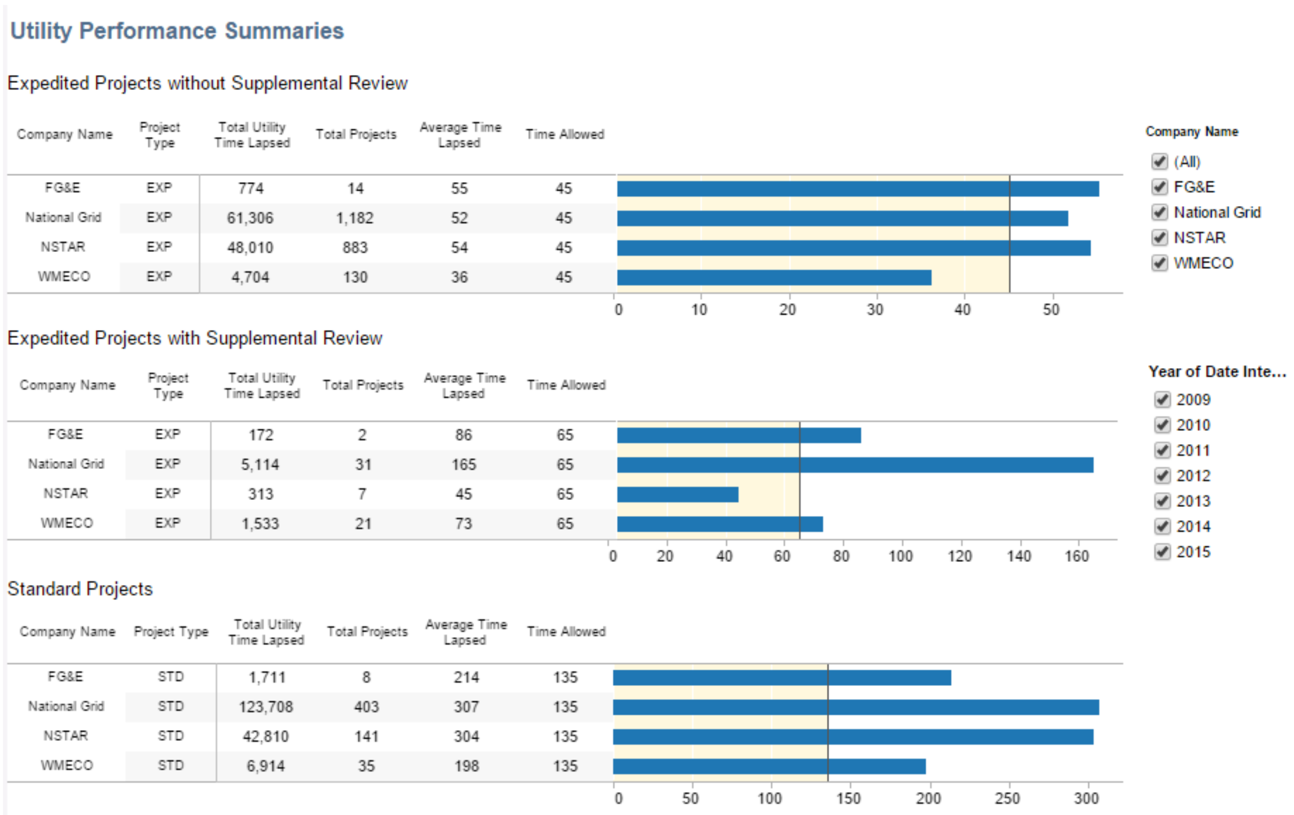


Figure 7.17 Publically available data on DG application process time in Massachusetts (source [40])



Utility Performance Summaries

Expedited Projects without Supplemental Review

Company Name	Project Type	Total Utility Time Lapsed	Total Projects	Average Time Lapsed	Time Allowed
FG&E	EXP	774	14	55	45
National Grid	EXP	61,306	1,182	52	45
NSTAR	EXP	48,010	883	54	45
WMECO	EXP	4,704	130	36	45

Expedited Projects with Supplemental Review

Company Name	Project Type	Total Utility Time Lapsed	Total Projects	Average Time Lapsed	Time Allowed
FG&E	EXP	172	2	86	65
National Grid	EXP	5,114	31	165	65
NSTAR	EXP	313	7	45	65
WMECO	EXP	1,533	21	73	65

Standard Projects

Company Name	Project Type	Total Utility Time Lapsed	Total Projects	Average Time Lapsed	Time Allowed
FG&E	STD	1,711	8	214	135
National Grid	STD	123,708	403	307	135
NSTAR	STD	42,810	141	304	135
WMECO	STD	6,914	35	198	135

Figure 7.18 Publically available data on utility performance in Massachusetts (source [40])

7.4.6 Utah

Utah requires the state's only investor-owned utility, Rocky Mountain Power (RMP), and most electric cooperatives* to offer net-metering to customers who generate electricity using solar energy, wind energy, hydropower, hydrogen, biomass, landfill gas, geothermal energy, waste gas or waste heat capture and recovery. The bill that established net metering also established some basic rules for interconnection. In April 2010, the Utah Public Service Commission (PSC) adopted final rules for interconnection. The rules described below took effect April 30, 2010.

Utah's interconnection rules are based on the FERC interconnection standards for small generators. Utah's rules for interconnection include provisions for three levels of interconnection for systems up to 20 MW in capacity, based on system complexity. Interconnection requirements, standards and review procedures are divided into three levels:

- Level 1 interconnection applies to inverter-based systems with a maximum capacity of 25 kW. These systems must comply with the IEEE 1547 and UL 1741 standards, and other applicable standards. An external disconnect switch is not required for inverter-based systems 10 kW or less.
- Level 2 interconnection applies to systems with a maximum capacity between 25 kW and 2 MW, or that fail to qualify for Level 1 interconnection. These systems also must comply with the IEEE 1547 and UL 1741 standards, and must be connected to the distribution grid. An external disconnect switch may be required. There are specific limitations on a single system's potential impact and the aggregate potential impact on the grid under Level 2 interconnection, and the review process is more involved than the review process for Level 1 interconnection.
- Level 3 Interconnection applies to systems 20 MW or less that do not qualify for either Level 1 or Level 2 interconnection. Level 3 interconnection may require studies involving project scope, feasibility, grid impact. Any study fees will be invoiced to the interconnection customer, but are not to exceed 125 % of the utility's non-binding "good faith estimate" of the cost of the study.

* Beginning in March 2008, electric cooperatives serving fewer than 1,000 customers in Utah may discontinue making net metering available to customers that are not already net metering. In addition, electric cooperatives not headquartered in Utah that serve fewer than 5,000 customers in Utah are authorized to offer net metering to their Utah customers in accordance with a tariff, schedule or other requirement of the appropriate authority in the state in which the co-op's headquarters are located.

7.5 Practical rules - simplified evaluation methodologies worldwide

Based on the information contained in CIGRE WG6.24 report [16] on the practices of several DSOs, rules of thumb and simplified evaluation methodologies are summarized in this section to supplement screening criteria from U.S.

It is worth mentioning that non-compliance with some of these rules doesn't necessarily entail rejection of the examined DG interconnection. Rather, detailed studies are typically required, at a subsequent level of more detailed technical evaluation, before passing a final verdict. Moreover, it is important to state that the following rules do not include all the applicable criteria by DSOs but only those used as rules of thumb. These might assist SEE DSO in their efforts to develop simplified procedure for small DGs.

Criteria applied by DSOs for the determination of hosting capacity, especially in the form of simplified rules and guidelines, can be separated in the following main categories:

- Criteria based on the installed transformer capacity of HV/MV and MV/LV substations and the thermal limits of MV and LV feeders are typically applied, including N-1 considerations at substation level and possibly the reverse power flow capability of transformers.
- Criteria related to the short circuit capacity are also quite popular and relatively easy to implement. They ensure that the design fault level of the network is not exceeded, or they simply provide a maximum permitted DG capacity as a ratio of the fault level at the PCC.
- The load-to-generation ratio also forms the basis of simplified connection rules, derived either from islanding prevention considerations or voltage regulation problems.

Criteria related to or based on ratings/thermal limits

- (Belgium) The aggregate power of DG must not exceed the HV/MV transformer power, taking into account that the N-1 criterion should be met.
- (Belgium) As for LV networks, the aggregate power of DG must not exceed the MV/LV transformer power rating.
- (Canada) The Thermal Capacity limit represents the estimated name plate amount of DG that can be added to that bus or station mainly based on the reverse flow limits of the transformer according to the following rule: Reverse power flow must not exceed 60 % of station capacity (sum of 60 % maximum MVA rating of the single transformer and the minimum station load).
- (Canada) For transformers rated less than 50 kVA (typically 10 kVA and 25 kVA), the total connected generation capacity, including the proposed generation, must be limited to 50 % of the nameplate kVA rating of the respective transformer winding.
- (Canada) For generators connected between line-to-neutral terminals of the transformer secondary, the total connected generation capacity shall not exceed 25 % of the transformer nameplate kVA rating.
- (Czech) Available connection capacity at the 110 kV/HV substations. The maximum accumulated power that can be connected to the HV network, including both existing and dedicated feeders, is roughly limited by the installed transformer capacity at N-1 conditions, plus the annual minimum substation load (correction coefficients may apply, further limiting the hosting capacity).
- (Italy) The aggregate nominal power of all DG must not exceed 65 % of the nominal power of the HV/MV transformer.
- (Italy) The aggregate nominal power of all DG must not exceed 60 % of the thermal limit of the feeders.
- (Portugal) The aggregate DG nominal power that can be connected to a MV/LV transformer should not exceed 25 % of the nominal power of the transformer.
- (South Africa) The aggregate DG nominal power that can be connected to all shared LV feeders should not exceed 25 % of the nominal power of the transformer.
- (South Africa) The aggregate DG nominal power that can be connected to a shared LV feeder should not exceed 25 % of the circuit breaker rating.
- (South Africa) The aggregate DG nominal power that can be connected to a dedicated LV feeder should not exceed 75 % of the circuit breaker rating.
- (South Africa) The aggregate DG nominal power that can be connected to a MV/LV transformer should not exceed 75 % of the nominal power of the transformer.
- (South Korea) The aggregate nominal power of all DG connected to MV network must be lower than 20 % of the HV/MV transformer nominal power. When the aggregate nominal power of all DG is less than 15 % of HV/MV transformer nominal power, the proposed DG can be connected to the HV/MV transformer without detailed evaluation procedure.

- (South Korea) The aggregate nominal power of all DG connected to a MV feeder must not exceed the line operating limit (typically 10 MW). When the aggregate nominal power of all DG in a feeder is less than 15 % of the line operating limit, the proposed DG can be connected into the feeder without detailed evaluation procedure.
- (South Korea) When the aggregate nominal power of all DG (including the proposed one) that are connected to a MV/LV transformer is less than 25 % of the nominal power of the MV/LV transformer, the proposed DG can be connected to a shared LV feeder without detailed evaluation procedure.
- (South Korea) When the aggregate nominal power of all DG (including the proposed one) that are connected to a MV/LV transformer is less than 50 % of the nominal power of the MV/LV transformer and the nominal power of the proposed DG is less than 25 % of the nominal power of the MV/LV transformer, the proposed DG can be connected to a dedicated LV feeder without detailed evaluation procedure.
- (Spain) The aggregate nominal power of DG must be less than 50 % of the thermal limit of the feeder where the DG will be connected to.
- (Spain) As for the transformers and the substations, the aggregated nominal power of DG must be less than 50 % of their capacity.

Criteria related to or based on short circuit capacity

In general, all DSOs ensure that the eventual fault level, after considering all DGs (and active loads) of the network, remains below the design short circuit capacity of the network and the short circuit withstand capabilities of individual equipment (e.g. make and break currents of breakers). Some DSOs (e.g. in the USA) further require that a safety margin should remain available. For instance, all DG shall not cause any distribution protective devices and equipment, or customer interconnection equipment, to exceed 87,5 % (or 85 % or 90 %) of the short circuit interrupting capability.

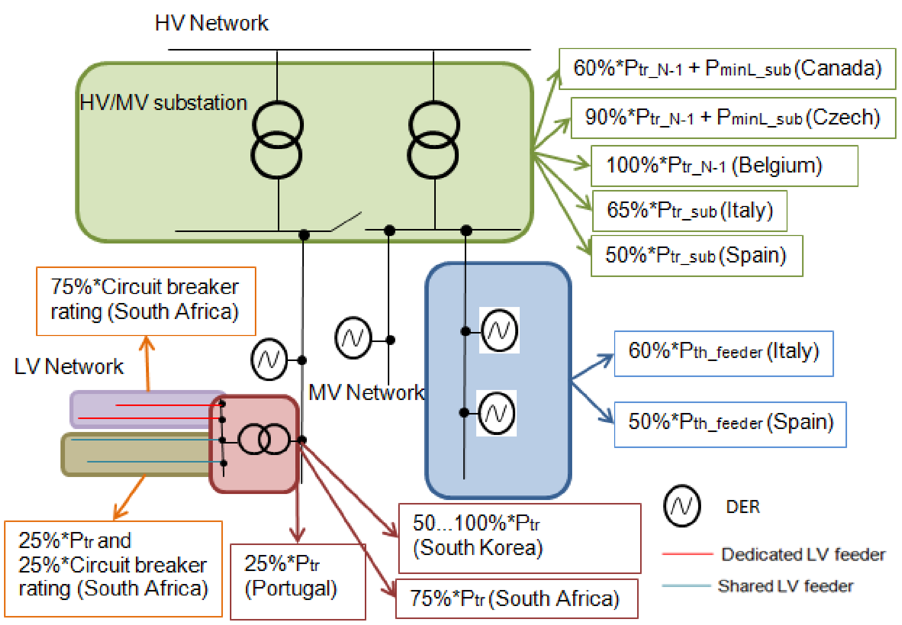


Figure 7.19 Criteria related to or based on short circuit capacity; source CIGRE WG C6.24 [16]

- (China) The aggregated nominal power of the connected DG must not be greater than 10 % of the short-circuit at the PCC.

- (South Korea) When the aggregate nominal power of all DG is less than 15 % of HV/MV transformer nominal power and the aggregate nominal power of all DG in feeder is less than 15 % of the line operating limit, the proposed DG can be connected to the network without detailed evaluation procedure concerning short-circuit contribution.
- (Spain) The aggregate nominal power of the connected DG must not be greater than 10 % of the short-circuit capacity at the PCC in order to avoid undesirable impact to power quality.
- (USA) The aggregate short circuit contribution ratio of all DG on the distribution feeder must be 0,1 (10 %) or less. Otherwise, detailed studies are required.
- (USA) If the proposed DG is to be interconnected on a shared secondary, the short circuit contribution of the DG must be 2,5 % or less than the interrupting rating of the DG's interconnection system.
- (USA) The SCC of the DG must be lower than 25 % of the feeder short circuit at the DG location.

Criteria based on the load-to-generation ratio

- (Canada) Area load limit: Maximum allowable generation will be equal to a portion of the feeder or substation annual minimum load (typically 50 %-100 %) depending on the type of generation and the sophistication of the protection system.
- (Canada) The total generation to be interconnected to a distribution system circuit line section, including the proposed generator, will not exceed 7 % of the annual line section peak load on F-class feeders and 10 % on M-Class feeders (see note*).
- (South Africa) The aggregate DG nominal power that can be connected to a MV feeder, including the DGs that are connected to the LV feeders of this specific MV feeder, is limited to 15 % of the feeder peak load.
- (USA) For interconnection of a proposed DG to a radial distribution circuit, the aggregated generation, including the proposed DG, on the circuit shall not exceed 15 % (see note*) of the line section annual peak load as most recently measured at the substation. Some DSOs apply this rule only for DG of 2 MW or lower. If this criterion is not met, there is a detailed evaluation procedure.
- (USA) The aggregate nominal power of the DG on the line section must be less than 100 % (see note*) of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the generating facility. Solar generation systems with no battery storage use daytime minimum load (i.e. 10 am to 4 pm for fixed panel systems and 8 am to 6 pm for PV systems utilizing tracking systems). Other DSOs apply a stricter limit (50 % of the minimum load).
- (USA) The aggregate nominal power of all DG on a feeder must be 5 % (see note*) or less of the total circuit annual peak load as most recently measured at the substation. Other DSOs apply a less strict limit (7,5 %). If this criterion is not met, there is a detailed evaluation procedure.
- (USA) If the DG is served by a three-phase four wire service or if the distribution system connected to the DG is a mixture of three and four wire systems, then aggregate nominal power of the DG must not exceed 10 % of the line section peak load.
- (USA) In secondary network systems, aggregate DG should represent 25 % or less of the total load on the network (based on the most recent peak load demand). This is the value at or below which inverter-based DG should not require costly changes to the utility system in order to accommodate the DG installation.

(note) Rationale behind the criterion (applicable in the majority of States in USA and in Canada)* - Apart from the need to address issues related to voltage regulation, reverse power flows and thermal limits of network equipment, the several load-to-generation ratios used as DG penetration limits derive also from unintentional

islanding considerations. If the aggregate nominal power of DG is less than one-third of the minimum load according to [17], it is generally agreed that, should an unintentional island form, the DG will be unable to continue energizing the load connected and maintain acceptable voltage and frequency. The origin of this 3-to-1 load-to-generation factor is an IEEE [19] paper based on simulations and field tests of induction and synchronous generation islanded with various amounts of power factor-correcting capacitors. It was shown that as the pre-island loading approached three times the generation, no excitation condition could exist to support the continued power generation. Because minimum loads are rarely well-documented and can vary, using a conservative load-to-generation criterion of 3-to-1 gives a margin against future changes in the customer's minimum load. However, a 2-to-1 (50 %) ratio may be acceptable in some applications. According to [17], if a 3-to-1 ratio applies and the minimum load is 50 % of the maximum, then a 15 % limit on the peak load is derived. According to [20], if the load to generation criterion is 3-to-1 and the minimum to maximum load ratio is 1-to-5, then the limit becomes 7,5 %. For installations in which the DG is interfaced through inverters, the need for margin to guard against future drops in minimum load also exists, and the 3-to-1 rule still seems prudent.

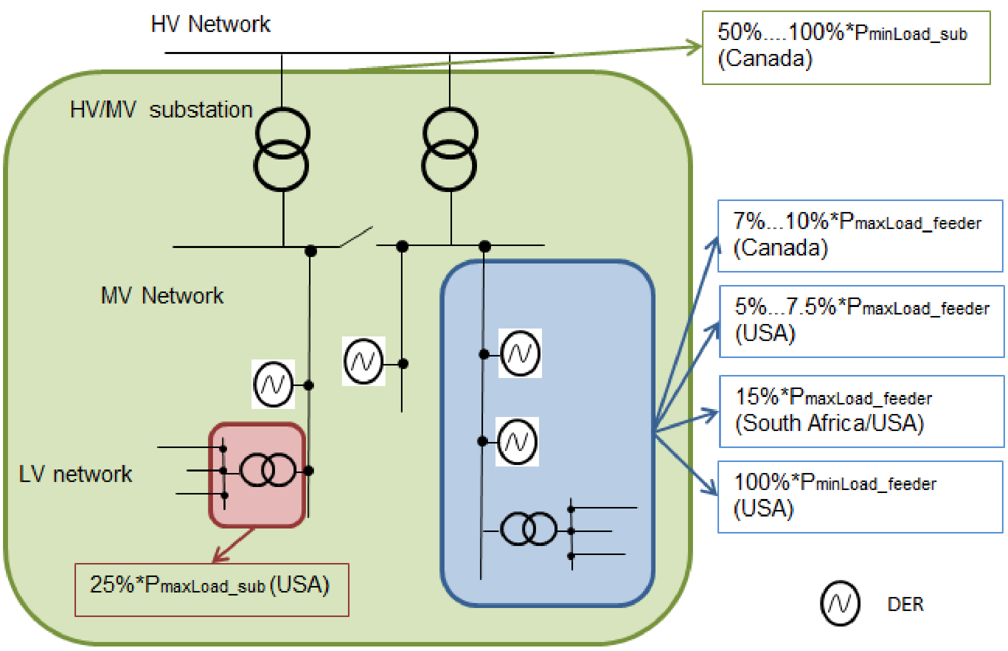


Figure 7.20 Criteria based on the load-to-generation ratio; source CIGRE WG C6.24 [16]

Other criteria

- (Canada) DG shall not increase distribution system electrical losses.
- (UK) 4 ≤ generator capacity (MVA) x distance from substation (km). For example, a 2 MVA generator can be connected up to 2 km from the primary substation or a 1 MVA generator can be connected up to 4 km away, etc.
- (USA) A proposed DG, in aggregate with other generation interconnected to the distribution side of a substation transformer feeding the circuit where the small generator facility proposes to interconnect, may not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity.
- (USA) When a proposed DG is to be interconnected on a single-phase shared secondary line, the aggregate generation capacity on the shared secondary line, including the proposed small generator facility, may not exceed 20 kW. If the aggregate generation capacity is in excess of 20 kVA, the voltage supplied to other customers who share the secondary conductors could exceed acceptable limits.

7.6 Timelines – District of Columbia small interconnection rules

In the U.S. the review process typically involves a series of steps, with a timeline associated with each one [33]. The lowest level review process, typically for smallest, certified units, has a fast-track, or expedited, process. As one moves up through the levels, the timelines become longer. The highest review level, which should apply to all units greater than 10 MW, plus other units that don't pass lower screens, should apply reasonable and explicit timelines similar to the following process of District of Columbia small interconnection rules:

- *By mutual agreement of the parties, the scoping meeting, interconnection feasibility study, interconnection impact study, or interconnection facilities studies may be waived.*
- *Within 10 business days from receipt of an interconnection request, the utility shall notify the interconnection customer whether the request is complete.*
- *When the interconnection request is not complete, the utility shall provide the interconnection customer a written list detailing information that must be provided to complete the interconnection request.*
- *The interconnection customer shall have 10 business days to provide appropriate data in order to complete the interconnection request or the interconnection request will be considered withdrawn.*
- *The parties may agree to extend the time for receipt of additional information.*
- *The interconnection request shall be deemed complete when the required information has been provided by the interconnection customer or the parties have agreed that the interconnection customer may provide additional information at a later time.*
- *A scoping meeting will be held within 10 business days, or other mutually agreed to time, after the utility has notified the interconnection customer that the interconnection request is deemed complete.*
- *When the parties agree at a scoping meeting that an interconnection feasibility study shall be performed, the utility shall provide to the interconnection customer, no later than 5 business days after the scoping meeting, an interconnection feasibility study agreement, including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.*
- *When the parties agree at a scoping meeting that an interconnection feasibility study is not required, the utility shall provide to the interconnection customer, no later than 5 business days after the scoping meeting, an interconnection system impact study agreement, including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.*
- *When the parties agree at the scoping meeting that an interconnection feasibility study and system impact study are not required, the utility shall provide to the interconnection customer, no later than 5 business days after the scoping meeting, an interconnection facilities study agreement including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.*
- *An interconnection system impact study shall be performed when a potential adverse system impact is identified in the interconnection feasibility study.*
- *The utility shall send the interconnection customer an interconnection system impact study agreement within 5 business days of transmittal of the interconnection feasibility study report.*
- *Before the interconnection facilities study is conducted, within five business days of completion of the interconnection system impact study, a report will be transmitted to the interconnection customer with an interconnection facilities study agreement that includes an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.*
- *Upon completion of the interconnection facilities study, and with the agreement of the interconnection customer to pay for the interconnection facilities and upgrades identified in the interconnection*

facilities study, the utility shall provide the interconnection customer with a small generator interconnection agreement within 5 business days.

- *An interconnection customer shall have 30 business days, or another mutually agreeable time frame after receipt of the small generator interconnection agreement, to sign and return the agreement.*
- *When an interconnection customer does not sign the agreement within 30 business days, the interconnection request will be deemed withdrawn unless the interconnection customer requests to have the deadline extended.*
- *The request for extension may not be unreasonably denied by the utility.*
- *When construction is required, the interconnection of the small generator facility shall proceed according to milestones agreed to by the parties in the small generator interconnection agreement.*

7.7 Transparency and publicity practices adopted by DSOs

A growing number of jurisdictions are taking an active role to require that utilities make some amount information about the grid available to developers or to the public. Information about available line capacity and existing or pending generation interconnection requests can be critical to evaluating the viability of a particular project. Provision of this level of data in a pre-application report is emerging as a best practice in U.S. Publication of certain information, including interconnection queues with all current and proposed generators, available capacity on specific areas on the utility's grid, and "preferred" locations to interconnect also furthers the aims of transparency and efficiency. The more granular the information, the more useful it can be to help identify suitable project sites.

The aim of this section is to describe several practices adopted by DSOs so as to inform potential investors on the available hosting capacity of the networks (based on analysis contained in CIGRE WG C6.24 study, [16]). In this way, investors are assisted to make preliminary decisions regarding project placement and sizing.

For example in Canada, Hydro One has uploaded to its web site an excel file which calculates the station and feeder capacity having as input values the feeder, the kind of DG (technology) and the nominal power of DG (http://www.hydroone.com/Generators/Pages/StationCapacityCalculator.aspx). The output of this calculator is "pass" or "fail" (*Figure 7.21*). In this way, Hydro One provides a preliminary study for the availability of the capacity in a specific feeder of a specific substation.

There are four criteria:

- Test 1 checks feeder loading and feeder generation capacity limitations on the distribution system. The total acceptable generation limit and acceptable capacity for connection to the feeder has already been reached. The total current shall not exceed either 200 A (for those feeders operating below 13,8 kV) or 400 A (for those feeders operating at or above 13,8 kV). This criterion was developed in response to Hydro One's experience of unacceptable feeder voltage fluctuations and power quality issues when a large amount of generation has been connected at a distance from the supply station, as well as to respect equipment limitations.
- Test 2 checks for available thermal capacity at the distribution or transformer station and upstream transmission station. Generation at the distribution station shall not exceed 60 % of the maximum MVA rating of the Hydro One single transformer and minimum station load. These limits are necessary to protect equipment that is currently installed in the station.

- Test 3 checks for the loading vs. generating balance on the distribution feeder. Total generation must not exceed 7 % of the annual line section peak load on F-class feeders or 10 % for M Class. Specifically, connection would not comply with anti-islanding distribution system requirements.
  Important note: A proposed "micro-FIT" connection (≤ 10 kW) may fail Test 3 while a FIT* project (over 10 kW) may pass at the same station and feeder. The Station & Feeder Capacity Calculator takes into account that the last mentioned projects will have connection requirements which will be performed at the expense of the generator. A Connection Impact Assessment (CIA) is performed for FIT projects over 10 kW to identify connection requirements and associated costs.*
  **micro-FIT –residents and businesses who are interested in installing renewable electricity generation projects that are 10 kW or less in size;*
- Test 4 checks for available short circuit capacity at the distribution station and upstream transmission station. Short circuit limits at the Transmission Station high or low voltage bus must not be exceeded by the addition of generation facilities. As a result, connection of the project would create a fault level which is beyond the mandatory Transmission System Code limit, as specified in Appendix 2 of Transmission System Code.

For instance, a PV power plant with a nominal power of 1 MW can be connected ("Pass") to Feeder 3 of the ABERDEEN substation. On the other hand, a wind power plant with a nominal power of 3 MW cannot be connected ("Fail") to Feeder 3 of the ABERDEEN substation, as shown on *Figure 7.21.* However, the aforementioned methods(excel tool), used for the assessment of the available capacity, do not substitute the Connection Impact Assessment (CIA) which is mandatory for DGs over 10 kW.

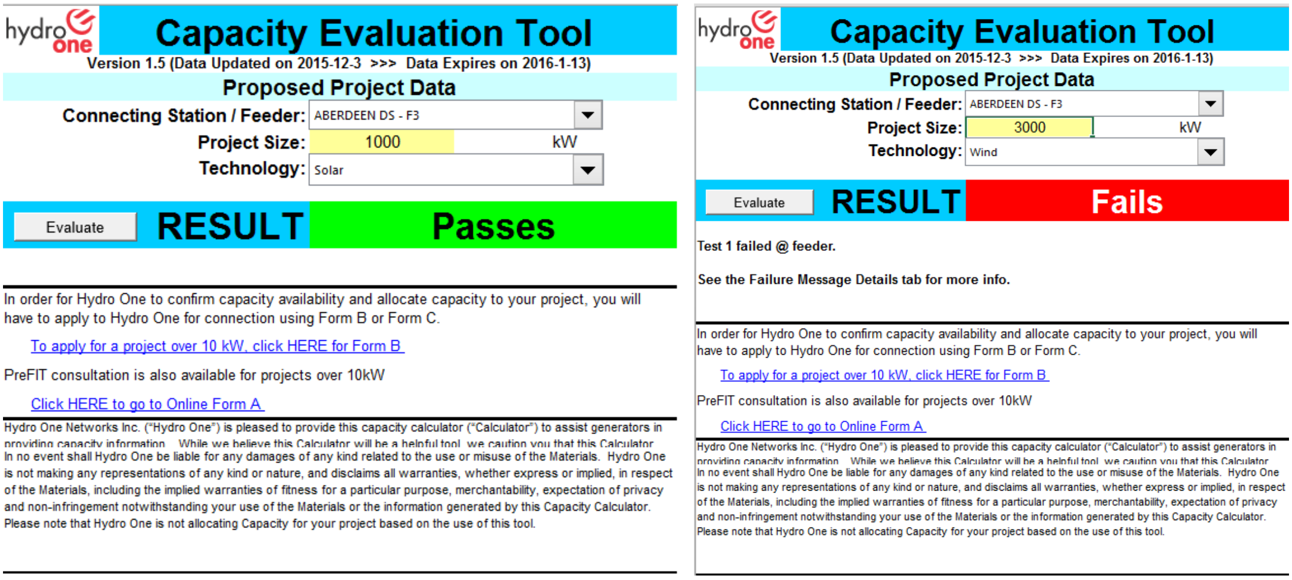


Figure 7.21 Capacity evaluation tool – excel file (Canada-Hydro Inc.)

Electricity Northwest (UK) applies the short circuit and thermal criteria to determine the capacity of the substations [42]. The following part of a map on *Figure 7.22* shows the distribution areas of 132/33kV substations. The area's colour indicates the impact of connection a 25 MW generator to the busbars at that substation:

- *Green*: The fault level is less than 95 % of the fault rating of the substation and likely to be able to connect a 25 MW generator.
- *Amber*: The fault rating is between 95 % and 100 % of the fault rating of the substation and connection of 25 MW generator will need consideration.

- *Red*: The fault level is in excess of 100 % of the fault rating of the substation and unlikely to be able to connect a 25 MW generator without reinforcement.

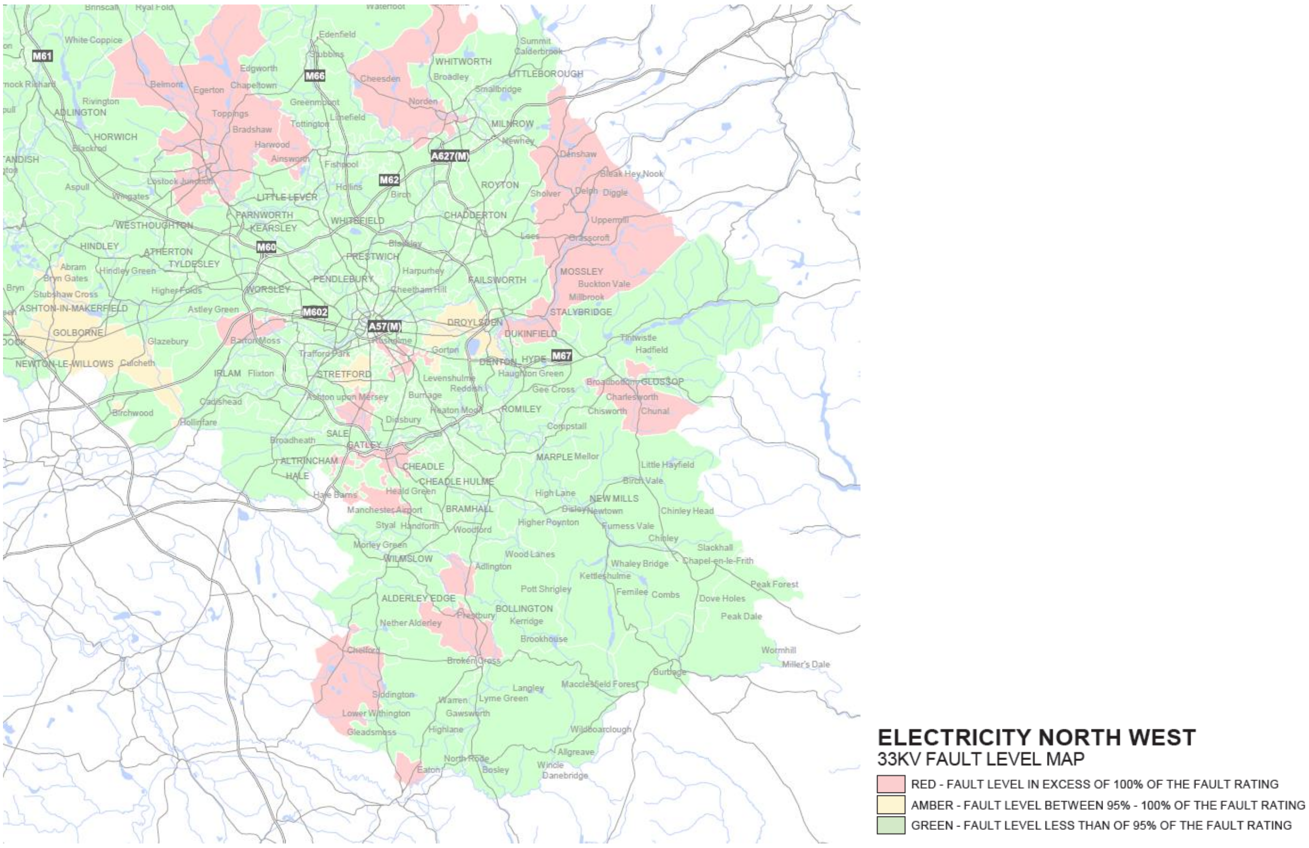


Figure 7.22 Map showing the available 132/33kV substation short-circuit DG capacity (UK - Electric Northwest [44])

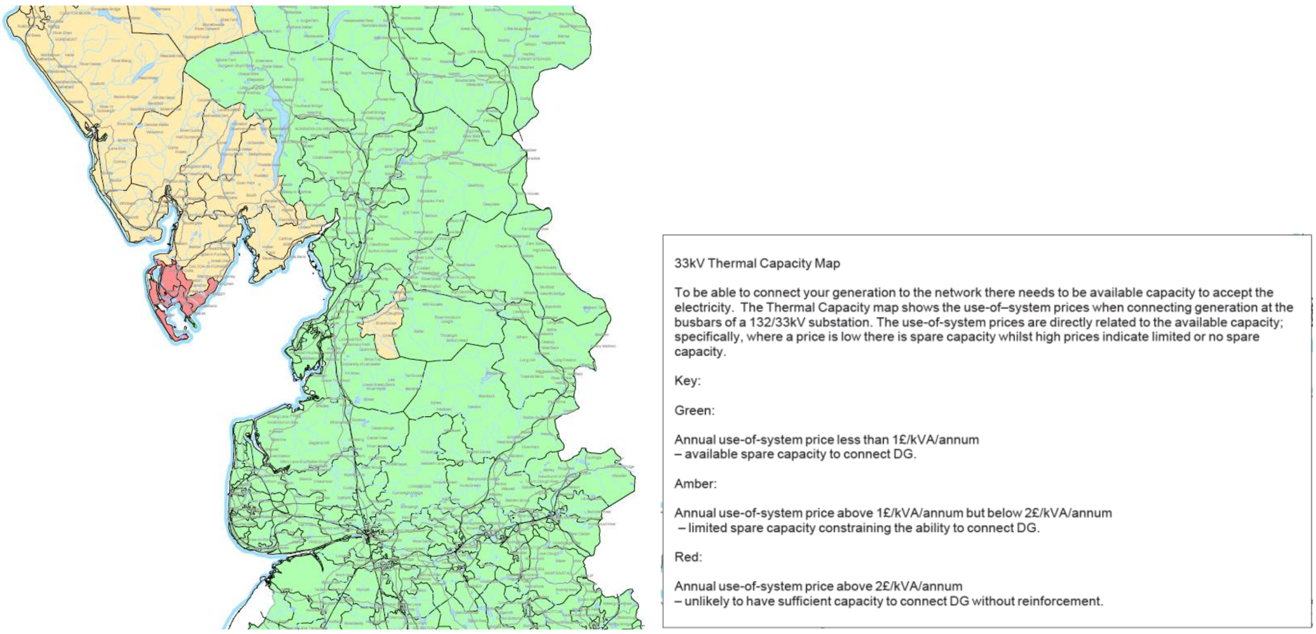


Figure 7.23 Map showing the available 132/33kV substation thermal DG capacity (UK – Electric Northwest [43])

The thermal capacity map on *Figure 7.23* shows the use-of–system prices when connecting generation at the busbars of a 132/33kV substation. The use-of-system prices are directly related to the available capacity; specifically, where a price is low there is spare capacity whilst high prices indicate limited or no spare capacity. The following part of a map shows the distribution areas of 132/33kV substations and the amount of spare capacity available when connecting generation at the busbars of a 132/33kV substation. The Red/Amber/Green on the map show the likelihood that a new generator would create the need for reinforcement on the Electricity North West distribution network as follows:

- *Green*: (annual use-of-system price less than 1£/kVA/annum) Available spare capacity to connect DG.
- *Amber*: (annual use-of-system price above 1£/kVA/annum but below 2£/kVA/annum) Limited spare capacity constraining the ability to connect DG.
- *Red*: (annual use-of-system price above 2£/kVA/annum) Unlikely to have sufficient capacity to connect DG without reinforcement.

There are also similar to the above maps for both 33/11 kV and 33/6.6 kV substations [42].

Map on *Figure 7.24* shows the distribution areas of 33/11kV and 33/6,6kV substations. The area's colour indicates the impact of connection a 10 MW generator to the busbars at that substation.

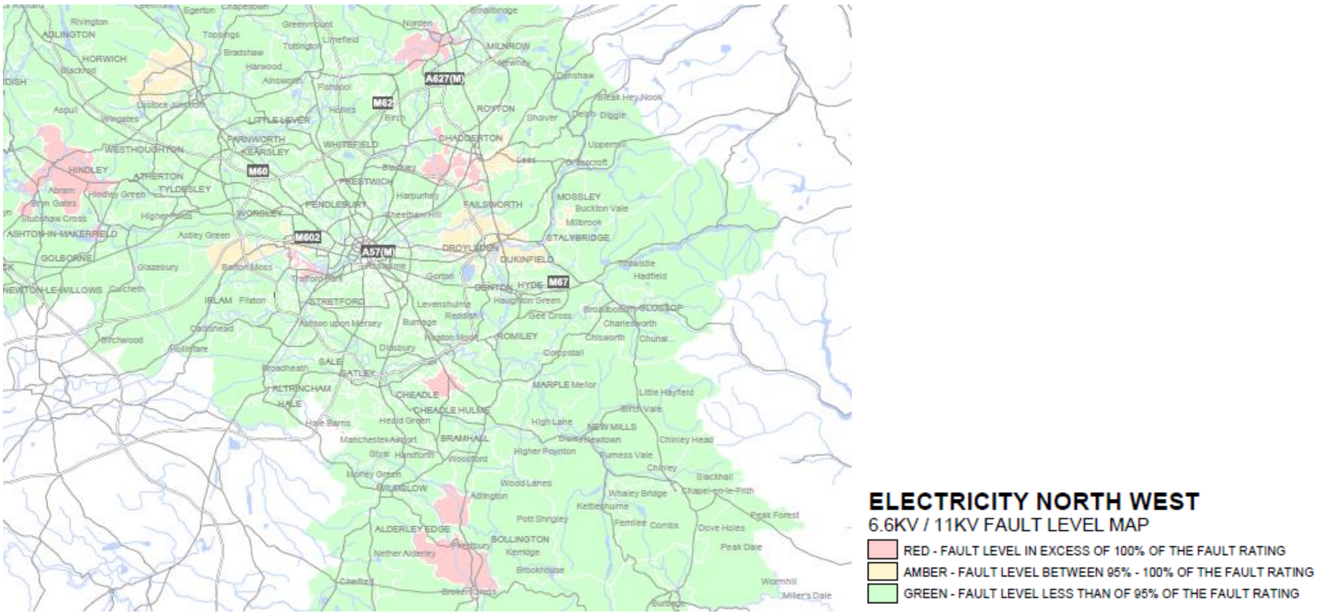


Figure 7.24 Map showing the available 33/11kV and 33/6,6kV *substations short-circuit DG capacity (UK – Electric Northwest)*

The thermal capacity map on *Figure 7.25* illustrates the amount of spare capacity available when connecting generation at the busbars of a 33/11kV or 33/6.6kV substations.

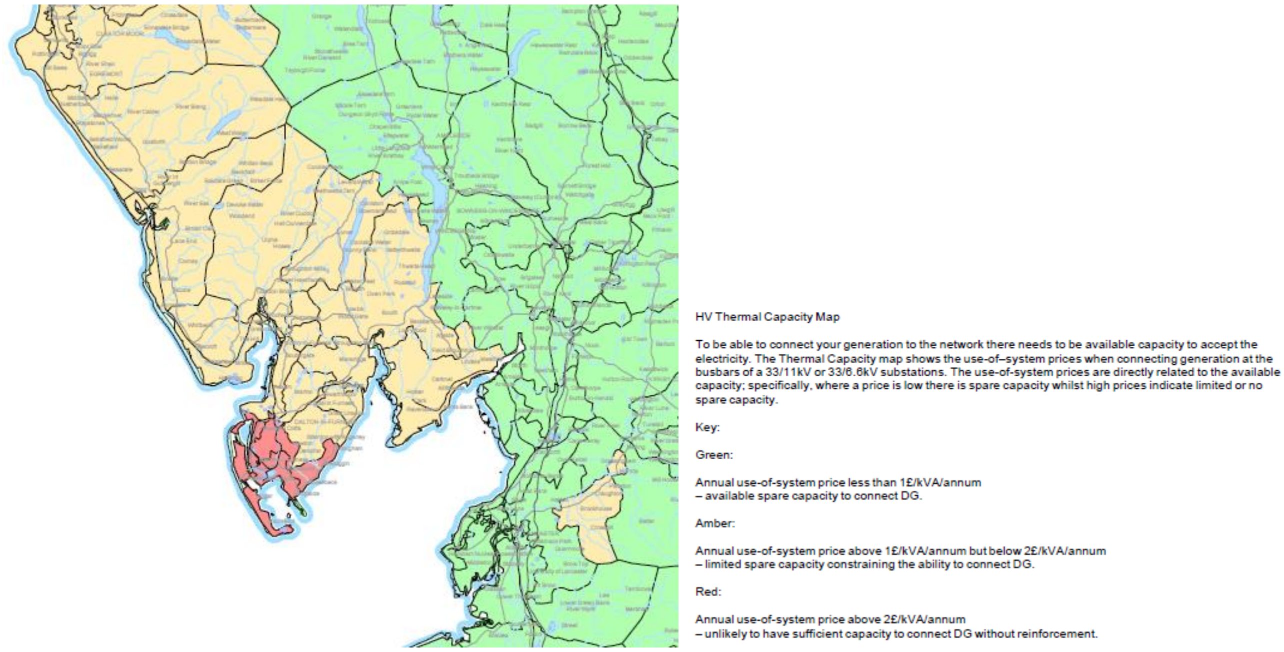


Figure 7.25 Map showing the available 33/11kV and 33/6,6kV *substations thermal DG capacity (UK – Electric Northwest)*

7.8 EU approaches to mitigate virtual saturation and speculation in grid interconnection procedure

Virtual saturation refers to a situation in which a portion of the grid could theoretically allow connection of some power plants but cannot practically proceed because its whole capacity is reserved by plants that are not yet connected. Usually, grid capacity is reserved before the plant is built, and this may lead to a situation in which some projects in development take up all the available capacity, thus making it impossible for other investor to request connection for other projects that they may want to develop, as no more capacity can be allocated. Virtual saturation leads to a number of disadvantages for both plant operators and grid operators: the grid operator, whose priority is to ensure grid stability, is forced to refuse other projects as a consequence of this situation. What is maybe even more severe in the long-run is the fact that virtual saturation may prevent grid operators from developing the grid appropriately. As it is unclear what projects will be realized, the grid operator is unable to assess what grid developments will be necessary. It is therefore hindered in setting up a master grid development plan that takes DG growth accurately into account.

Speculation usually occurs in connection with virtual saturation. In this context, it refers to the practice of reserving all available capacity on the grid in order to subsequently sell the reserved capacity to other producers who may need it. This practice usually is able to take up all available capacity and thus to create barriers for new plants in the connection phase. One applied solution is the introduction of a capacity reservation fee, which however has also the effect of moving the stranded asset risk from the grid operator to the plant operator.

EU countries are currently following two different approaches to mitigate virtual saturation [23]:

- One solution is to <u>introduce for the grid connection process a set of intermediate steps</u>, each of them ending with a realistic and appropriate milestone that the project developer has to reach within a certain period of time (e.g. first step submission of building permissions, second step financial guarantees and so on until the grid connection process is completed). After achieving the first steps, the project developer may reserve a certain amount of capacity for a defined period of time. If a project developer fails to reach the next milestone in the given time, the reservation expires and the developer has to restart with the first step. However, in case the project developer is not responsible for the delay, for example when waiting for administrative decisions, the deadlines for fulfilling the milestones should be extended. The restructuring of the process would prevent projects from being idle and would thus support a quick implementation of projects. The suggested process would provide grid operators with a clearer understanding of which projects will be commissioned and when they will be ready. Such knowledge would help them to assess how much capacity will be connected in a conceivable period of time and to accommodate the own planning. As a consequence, the process would be less stressful for grid and plant operators. However, such a deep planning would require more communication and coordination between all actors. Moreover, a more sophisticated connection process could become a challenge for less experienced DG installers. Thus, this may provide some difficulties. The described approach has been applied among others in France and to some extent in Estonia and Germany.

- Another solution might be to introduce a reservation fee to be made by the plant developer when applying for the connection permit. The distinctive feature of the payments is that developers have to pay in advance to the connection process and that thus the stranded asset risk is moved from grid operators to plant operators. The introduction of a reservation fee has two major advantages: First, the costs will entail a financial risk, considering that the investment will be futile if the reserved capacity cannot be sold in due time. As a consequence, speculative behaviour will become more risky and thus less attractive. Secondly, the recipient of the reservation – usually the State or the grid operator – could use the fee as an additional resource for grid development. The main drawback of these payments is that project developers would have additional expenses before the investment would pay off; this can pose a barrier to smaller actors at the market, resulting in a market concentration at a very early stage. The introduction of reservation fees has taken place among others in Bulgaria and Poland, and has been discussed in Czech Republic.

Apart from which solution will be chosen, it should be also discussed whether these solutions should be applied only to new projects or also to existing projects that are currently blocking the grid and causing virtual saturation. The application of the new rules would interfere with the legal principle that measures should not have retroactive effect. On the other hand, if virtual saturation is currently taking place, it might be wise to take this option into account.

7.9 Allocation of distributed generation grid connection cost

There seems to be no clear answer to the question of how to allocate DG grid connection cost between the parties involved in such a way that the allocation is considered as reasonable or just by all stakeholders. Reasons for this are:

- Many parties are involved. The grid company and the DG are concerned directly, but also governments and regulators and their goals and philosophies play an important role.
- Due to the historical development of the grid, the cost to connect a similar DG may differ significantly between different locations and the question of how to divide the consequences of the historical development of the grid between the involved parties is a complicated one.

At least four mechanisms for the allocation of DG grid connection cost can be identified (*Figure 7.26*), namely:

- A *shallow* connection tariff: the connection tariff charged by the grid company to the DG operator only covers the cost of a connection between the location of the DG and the nearest point of the grid with an appropriate voltage level, independent of whether the grid at this location has indeed sufficient capacity to transport the DG's output power or not.
- A *deep* connection tariff: the tariff charged by the grid company to the DG operator covers all expenses that the grid company incurs due to the connection of the DG.
- A *mixed* connection tariff: the tariff charged by the grid company to the DG operator covers the cost of the connection between the location of the DG and the nearest point of the grid with an appropriate voltage level, as well as a certain fraction of any further (or 'deep') investments that may be needed.
- A *true* connection tariff: the tariff charged by the grid company to the DG operator covers the cost of a connection between the location of the DG and the nearest point of the grid with an appropriate voltage level where the grid has sufficient capacity to transport the DG's output power.

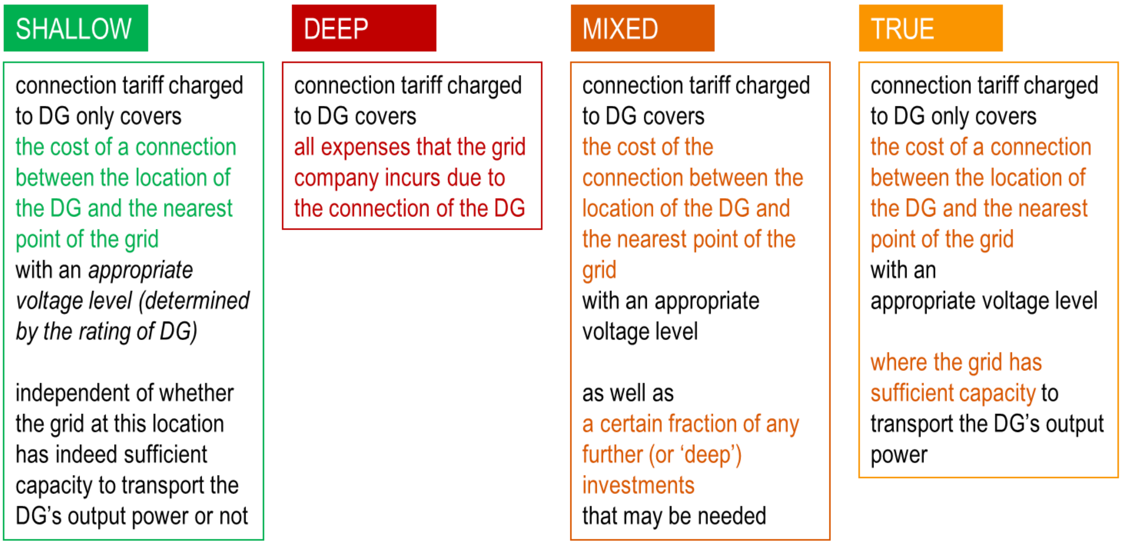


Figure 7.26 Connection cost possible allocation mechanisms

Based on a discussion between the Dutch grid companies and the Dutch Office for Energy Regulation a set of possible criteria for the evaluation of DG connection cost allocation mechanisms are commented upon in [21] (*Figure 7.19*). This study gives a brief overview of recommendations from CIGRE Report [21] regarding allocation of DG grid connection cost.

For choosing one of the mechanisms for the allocation of the connection cost described above, one of course needs criteria to evaluate the various possibilities. In the discussion between grid companies and the Dutch Office for Energy Regulation, the following criteria were identified (*Figure 7.27*):

- Compatibility with applicable legislation: if a mechanism is not feasible within the boundaries imposed by higher level legislation (e.g. Electricity Law), it cannot be implemented without changing the law. Practically, this means that it would take much time to implement it.
- Promotion of DG operator efficiency: a mechanism should promote the efficiency of the DG operator, which means that the DG operator should have an incentive to connect the DG in such a way that total cost (both of the DG operator and the grid company) is minimized.
- Promotion of grid company efficiency: analogously, a mechanism should promote the efficiency of the grid company, which means that also the grid company should have an incentive to connect the DG in such a way that total cost (both of the DG operator and the grid company) is minimized.

- Cost of allocation mechanism: the mechanism must be prevented from becoming too complex and thus expensive. In other words, if a mechanism guarantees minimization of total connection cost, but execution of the mechanism is very expensive, total cost (both of the DG connection and of the execution of the mechanism itself) could be higher than when a simpler mechanism is applied, even when the point of connection in that case might be less than optimal. In terminology of economics, this type of cost can be compared to transaction cost.
- Cost reflectivity: the true cost associated with the connection of a DG should somehow be reflected in the connection fee paid by its operator. This does not necessarily mean that the DG operator has to pay all the cost. It implies, however, that it should at least be true that the more the total cost of the connection, the higher the fee paid by the DG operator. Stated differently, it should not be possible that the allocation mechanism works out in such a way that a DG operator whose DG is relatively cheap to connect to the grid can pay the same or even more than another DG operator whose DG is much more expensive to connect to the grid.

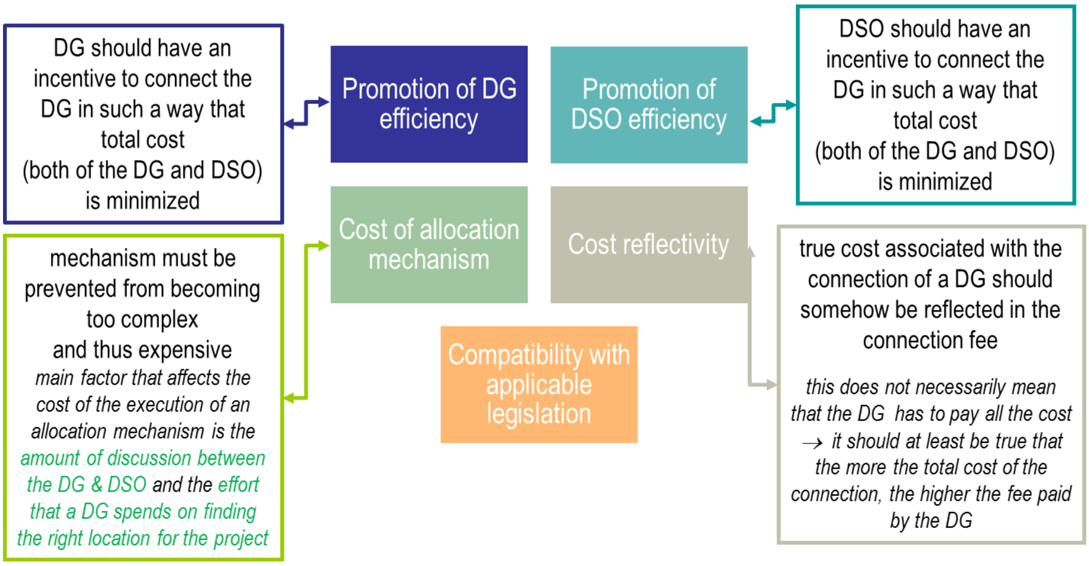


Figure 7.27 Criteria for evaluation of allocation mechanisms

In CIGRE Report [21] the possible mechanisms have been evaluated using the identified criteria. Results are summarized in *Table 7.5*.

As for the first criterion, compatibility with the applicable legislation, it is clear that the score of the different mechanisms on this criterion will be very much dependent on the legislative framework. It is hence not possible to draw general conclusions in this respect and the score of the mechanisms mainly depends on (supra)national laws. Therefore * in *Table 7.5*.

With respect to the second criterion, promotion of DG operator efficiency, it can be stated that the larger the part of the connection cost the DG operator has to pay, the more efficient it will operate in order to reduce its cost. Hence, the deep connection tariff will promote the efficiency of the DG operator mostly, whereas the shallow connection tariff does hardly promote the efficiency of the DG operator. The balance between the mixed and the true connection tariff depends on the part of the cost to be paid by the DG operator in case of the mixed connection tariff: when the fraction of the connection cost to be paid by the DG operator is small, a true connection tariff will better promote the DG operator efficiency than a mixed connection tariff, whereas when a large fraction of the cost should be paid by the DG operator, it will be the other way around.

Concerning the third criterion, promotion of grid company efficiency, the score of the mechanisms is exactly the opposite as in case of the second criterion. A shallow connection tariff will promote the efficiency of the grid company mostly, as the grid company can only charge a fixed tariff, so that it benefits when it can keep the cost lower than the connection fee, whereas when the cost becomes higher, the grid company itself should pay it. On the other hand, a deep connection tariff will not promote grid company efficiency, as it can pass through all the cost to the DG operator. For the true and the mixed connection tariff, the balance again depends on the division of the cost between grid company and DG operator in case of the mixed connection tariff: the higher the fraction of the cost to be paid by the grid company in case of the mixed connection tariff, the more the efficiency of the grid company will be promoted, whereas when the fraction of the connection cost to be paid by the grid company is very low, a true connection tariff may better promote grid company efficiency than a mixed connection tariff.

With respect to the fourth criterion, the cost of the allocation mechanism, it can be remarked that the main factor that affects the cost of the execution of an allocation mechanism is the amount of discussion between the DG operator and the grid company that will take place and the effort that a DG operator spends on finding the right location for its installation. In case of the shallow connection tariff, the DG operator will not engage in any discussion with the grid company and will neither spend much effort on finding the most suitable location from the perspective of connecting to the grid, because it only pays a fixed connection tariff and hence has no incentive for this. In the case of the other allocation mechanisms, the DG operator will have to invest in engaging in a discussion with the grid company on the connection cost, as well as in finding a location that is suitable for the DG, so that the other three criteria perform more or less equally on this criterion.

Finally, the fifth criterion, cost reflectivity, is of importance; it is the DG operator that causes the cost. Hence, from the perspective of cost reflectivity, the deep connection tariff scores the best. The shallow connection tariff scores worst, because in this case, there is no direct relation between the real cost that the DG operator causes and the tariff it pays. The other two allocation mechanisms score the same, because in both cases, a certain part of the connection cost is paid by the DG operator.

Table 7.5 Evaluation of allocation mechanisms

Allocation mechanism Crierion	shallow	deep	mixed	true
DG efficiency	-	+	o	o
DSO efficiency	+	-	o	o
Mechanism cost	+	o	o	o
Cost reflectivity	-	+	o	o
Compatibility with legislation	*	*	*	*
** no general conclusion possible*				
+ positive (scores the best)				
o neutral				
- negative (scores the worst)				

As can be concluded from *Table 7.5*, there is no allocation mechanism that outperforms the other in every respect. Therefore, any allocation mechanism will be a compromise and the final choice depends on the weight that is assigned to the individual criteria.

In the observed SEE region “deep” approach prevails (see *Table 5.13*), causing investors doubts that the connection charges are high. Even though “deep” approach cannot be characterized as the worst possible choice (bearing in mind previously described evaluation results) one aspect should be highlighted. In the absence of transparency, a “deep” charging method may provide vertically integrated DSOs with more incentives and scope for discrimination than a shallow charging approach.

The Dutch situation can serve as an example of the actions undertaken. The discussion between the Dutch grid companies and the Dutch regulator was raised because the mechanism used at that time for the allocation of connection cost between the grid companies and the DG operator, which was the "shallow" connection tariff, led to unacceptable cost for the grid companies. The regulator accepted this point of view and it was decided that actions had to be undertaken quickly.

Due to the required quick implementation of a change of allocation mechanism, the first criterion, compatibility with existing legislation, became the most important criterion for the choice, because changing a law takes a considerable amount of time. Taking into account Dutch law, it was decided to change to a "true" connection tariff. As this example shows, the final choice for a connection mechanism depends on the situation, which to a large extent determines the weight assigned to each of the criteria.

Although this topic deserves extensive analysis, this report aims not to provide a comprehensive description of this topic (it is out of the scope of this study). The intention here was just to briefly tackle this topic to have a broader perspective of all the issues that shall be taken care of with regard of DG interconnection procedure.

Here it is worth to mention that the Policy Guidelines by the Energy Community Secretariat on Reform of the Support Schemes for Promotion of Energy from Renewable Sources from December 2015 suggest, among others, to consider "shallow" approach for the charging regime related to connection to the grids. These Guidelines argue that:

> *The cost for connection to the grids is an important part of the overall investment decision an investor in renewable energy has to take into consideration. It goes beyond the costs of connection and involves the ownership of assets, cost of operation and maintenance, etc.*
> *Transparency towards applicants has to be ensured and the rules for connecting to the power grid have to be based on objective and non-discriminatory criteria.*
> *In order to make sure producers can generate electricity where renewable resources are available, producers should be charged with the cost of connection to the nearest point in the public electricity network only ('shallow" connection cost) and not with the costs for reinforcement or expansion of the networks ("deep" connection costs). The T/DSO are the appropriate undertakings to create an optimal infrastructure by investing in grids reinforcement or expansion of the grids and socialize the cost for the ownership and maintenance of the network assets with all network users through regulated network tariffs.*

7.10 Means to increase the hosting capacity

DSOs that cannot profit from the DG capacity replacement value and operate under a passive network management regime will generally not profit from the presence of DG in their distribution network. Although low DG penetration levels do benefit the DSO somewhat, higher penetration levels result in a negative overall impact. The concentration of DG within the network is a particular influential factor: the more concentrated the presence of DG in the distribution network, the more negative the impact.

Regarding the means that are available to increase the hosting capacity, either from the DER side or from the DSO side, the information provided in [16] is summarized in the following. More detailed country overview can be found in Chapter 3 of this report.

- Shallow and deep connection works:
    - reinforcement, rearrangement or even construction of new network (LV, MV feeders, transformers etc),
    - construction of new HV/MV substations for interconnection of DG only ("DG collectors").

- Short-circuit:
  - usage of generator with lower fault current contribution, transformers with a higher impedance or fault current limiting reactor,
  - upgrade of network equipment to meet the increased fault level,
  - usage of sequential switching so as to reduce the fault current contribution of the connected DG.
- Voltage regulation:
  - replacement of HV/MV transformers with others equipped with increased tap range and readjustment of control settings of OLTC and of MV/LV transformer fixed taps (e.g. installation of MV/LV distribution transformers equipped with OLTC has been also proposed),
  - replacement of the feeder capacitor banks with switchable ones, to avoid overvoltages,
  - cancellation CTs to modify the OLTC settings,
  - installation of reactive power sinks (i.e. reactors) on the network.
- Other upgrades:
  - modifications so as to allow bidirectional power flow, such as replacement of breaker protection relays or reclosers etc.
- DG control:
  - reactive power or power factor control (there is a variety of ways that this method may be implemented; for instance, setting the power factor to a suitable fixed value and regulating the power factor as a function of active power generation or setting the reactive output power as a function of PCC voltage),
  - active power curtailment (DG active power curtailment is also a possibility to resolve voltage regulation and local congestion issues, though it is always a last resort due to its economic implications to the DG investment; see section 7.11 for Germany and UK practices),
  - more effective anti-islanding protection schemes.
- Future concepts (when the necessary conditions will be favourable for their deployment; i.e. smart-grid infrastructure, electricity market and regulatory framework, technical maturity etc.):
  - usage of SCADA software or other (smart grids, web interfaces etc),
  - decentralised storage and demand response (e.g. peak shaving),
  - coordinated voltage control on the distribution network (HV/MV and MV/LV substations and voltage regulators on the feeder).

7.11 Network capacity management

7.11.1 Coordination of all relevant actors

DSOs should be able to plan their grids well in advance to prevent bottlenecks in the most cost-effective way. Data acquired within distribution network monitoring and information exchange with TSOs and distributed energy resources could be very beneficial in this respect.

In addition, every connection request should be analysed and considered in the planning process in order to make the best of the existing network. According to the traditional regulatory approach to connection requests analysis currently applied in most countries, the network operator performs an individual analysis and provides an individual solution to each connection. The first connections may make use of the available capacity of the existent network. But once there is an increased demand for new DG connections in the same area and the available network capacity is limited this approach is not always optimal from the overall cost and network development perspective. First requests for connection get the available capacity of the existent network at a low cost, but as they increase they require more complex and expensive network development solutions. In countries where generators bear grid connection as well as grid reinforcement/extension costs ("deep" connection charges), this may make the individual projects economically unviable.

One way to tackle this issue is to allow for coordination of all relevant actors, including network operators, investors and local authorities in the analysis of connection requests.

Spanish "Evacuation Boards" approach

To rationalise the RES expansion and optimise the available energy resources, some Spanish regions created so-called "Evacuation Boards". They are characterised by a coordinated grid connection request process. RES installation plans are deployed and coordinated between the administration, RES investors and TSO and DSO. In these evacuation boards the TSO or DSO do not receive individual requests; they are collected by the regional administration and after a validation process submitted for an aggregated analysis to be made together by the DSO & TSO. The positive impact of the new networks for consumption (extra capacity for consumers) is also considered. In addition to the cost sharing mechanism (proportionally to the capacity assigned to each RES project), the covenants for the development of such infrastructures contain the necessary guarantees, payment and execution terms. Benefits of this approach include overall minimised network development and project cost, reduction of project risks thanks to the possibility to correctly analyse both the costs and timetables needed for the different RES penetration scenarios, and reduced time for acquiring all necessary administrative permits.

7.11.2 Deployment of "flexibility"

Network capacity management would encompass optimisation of network capacity via improved consideration of DGs in network planning. The DSO ability to identify areas with possible overload problems well in advance is a precondition for this. The options that should be further investigated include new network access options such as "variable network access contracts".

DG developers could have a possibility to select firm or variable access contracts based on their own business plan. Variable network access rights could be offered as a discounted connection contract for generation customers, with pre-defined mechanisms for DG to reduce their output to a predefined limit in infrequent situations, expected only for few hours per year. If only several hours of re-dispatching per year are needed to limit peaks of production and use network capacity more efficiently, those would be more than offset by an additional DG output in all other hours due to a higher installed DG capacity up to a certain point where the cost of net losses and curtailed generation become relevant to justify network reinforcement.

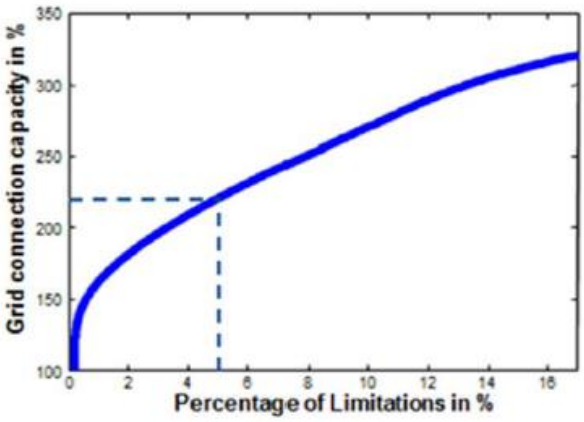


Figure 7.28 Variable access approach (Source: EWE Netz, [41])

A model example from EWE Netz (Germany) in *Figure 7.28* illustrates that limiting peak power in-feed of e.g. 5 % of the time would give an opportunity to connect 220 % more DG. In these cases, generation operators should be incentivised to choose this option, e.g. by reduced connection cost (cheaper but with limited guarantee of injection within a clearly defined framework) or other form of compensation. This could be executed either via direct contracts between DSOs and generators/load or indirectly between DSOs and aggregators who would pay a yearly option premium to DG/load and then offer flexibility to the DSO.

Today, variable access is precluded by obligation to compensate generators for any energy they are not allowed deliver in many jurisdictions. As outlined above, curtailment is often possible only to deal with short duration constraints; it is only temporary and automatically triggers grid adaptations such as reinforcement if they are deemed economically justifiable by the connected parties or DSO.

Optional non-firm access in UK

A form of variable network access for DG/RES exists e.g. in the UK (known as non-firm access). The conditions where a DSO can issue a curtailment instruction are set out in a connection contract agreed at the time of connection in return for a lower cost of connection.

Mandatory integration of feed-in management system in Germany

For example, the feed-in management rules in Germany define a flexibility obligation in form of a capped connection. The flexibility obligations, including the technical and regulatory possibility to be curtailed are spread over all production facilities above a certain capacity. The PV installation owner can choose to install a technical receiver device allowing for feed-in reduction by the network operator or to reduce the feed-in power to 70 % of the nominal power (installed power).

In practice, this measure leads to the loss of about 5% of energy feed-in from PV but allows connecting more DG to the network (and thus overall increased DG production). The producers are compensated for lost production. This curtailment regime enables an optimised use of the existing network, without jeopardising the business cases of new producers. It applies until the relevant grid development is made.

7.12 Smart grid benefits for distributed generation in the future

As observed in [33], the introduction of smart grids should unlock additional benefits from DG, including:

- Better handling of two-way power flows – DGs “export” power to the utility system when generation output exceeds any on-site load demand. That export makes it more difficult for the utility to provide voltage regulation and protective functions. Smart grid’s monitoring and communications functions should make these tasks easier for utilities.
- Easier deployment – With near-real-time information provided by the smart grid, the utility system operator will have detailed reports on the current conditions of individual feeders and loads. That should allow for simpler interconnection studies – or no study at all if certain new screens are passed – for some applications.
- Higher penetration levels – With real-time knowledge of conditions on feeders and communications between the grid and DGs and loads, some utility operating practices could be modified to facilitate higher concentrations of DG.
- Dynamic integration of variable energy generation – Smart grids will remotely monitor and report generation from DGs so automated systems and grid operators can dispatch other resources to meet loads.

- Reduced downtime – New inverter designs integrated with smart grids will allow DG to detect operational problems on the utility system, such as faults, and continue operating during some of these disturbances.
- Maintaining power to local “micro-grids” during utility system outages – Smart grids could allow for the formation of intentional islands of DG and loads that disconnect automatically when the grid is down and automatically resynchronize to the grid when conditions return to normal. Distributed generations within the microgrid can then continue to produce electricity to serve customers and loads within.
- Providing ancillary services – Smart grid’s built-in communications infrastructure will enable the grid operator to manage DG to provide reactive power, voltage support, and other ancillary services under some circumstances.

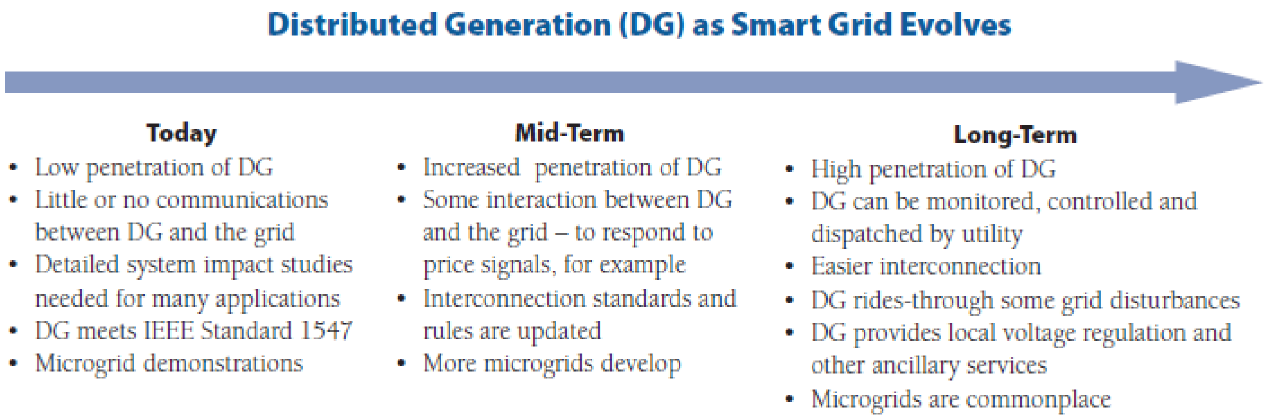


Figure 7.29 Potential smart grid benefits for DG in the future (source [33])

8 TASK 1B: CONCLUSIONS AND RECOMMENDATIONS FOR IMPROVEMENTS

The study consists of six SEE countries: Albania, Bosnia and Herzegovina, Croatia, Kosovo, Macedonia and Serbia, and 9 DSOs. The report aims not only to provide a comprehensive description of the status quo in the region, but also to identify actions required in order to implement streamlined integration of distributed generation in to the distribution system. U.S. and EU member states DSOs have also been used to provide an overview of their rules and requirements for integrating DGs and their applicability in SEE.

The attractiveness of support schemes and the ease with which renewable energy investors (operators) can gain access to networks and markets will become increasingly important for growth of RES. It will also be important that sufficient institutional capacity is available to implement documented policy and regulatory measures. As the distribution grids in the region already require significant investments to upgrade, with power outages, voltage levels and losses being regular problems in some areas, the uptake of DGs especially intermittent RES is treated with caution in most DSOs (countries).

Due to the low loading in SEE rural areas, when the required DG connection power is many times higher than the local load (i.e. DGs transfer most of the generated energy to the transmission system via the distribution system, thus violating the basic principle of distributed generation), this brings additional complexity and costs to DG and DSO. As observed by most of SEE DSOs, small HPP, and recently also photovoltaic PP, are usually built in rural areas with a small number of customers and low level of load, where the distribution network is not that well developed (weak) and power plants are far away from primary substations. Obviously the best effects of DGs on the distribution network have been observed in areas where minimum local load levels are approximatively equal to maximum connection power (i.e. DGs located close to the center of local consumption). The challenge for the region is how to accomplish, through development of regulatory framework, that DGs have incentive to become beneficial for the system?

In order to maintain the safety and reliability of the network, most DSOs are adopting international standards or defining their own. Besides available international standards, a large variety of national or local requirements appear to give an answer to those local necessities. These local factors are highly dependent on the geography, grid structure, type of technology and the amount of current penetration level of distributed generation. In SEE region, the diversity of distribution companies' guidelines, along with the vision of a future rapid uptake of distributed generation has inspired the review of local guidelines in this study. The purpose of the study is to build a picture of these standards and give a brief insight into the current stance the national distribution companies have via their policies.

This study has argued that the insufficiently regulated issues identified in SEE DSOs in the connection phase are:

- unclear regulations concerning the distribution of costs,
- information policy regarding costs,
- connection can be (temporarily) denied due to insufficient capacities,
- no explicit obligation to immediately reinforce grid to allow for connection either to allow provision of ancillary services to DSO by DGs,
- capacity limits for RES,
- connection moratorium due to lack of grid capacity,
- lengthy grid connection procedure (primarily due to DSO activities conditioned by other parties),
- complex procedures for small DGs.

It could be observed that countries in the region have a low share of DG operating on their grid, thus grid operation may simply not yet be problematic due to this low DG share. It is possible that with an increasing

DG share, the situation will dramatically change in the future and that thus early steps would be required to minimize future impacts.

Major barriers that might be expected in SEE DSOs in the grid operation phase:

- dispatching priority for RES,
- no proper regulation for congestion management (curtailment) yet,
- ancillary services not provided by DGs to DSO.

Main barriers identified in SEE DSOs in the grid development phase are as follows:

- DGs are not adequately included in distribution network development plans; i.e. in order to better align the pace of grid and DG development,
- lack of proper incentives for DSO and DGs.

The main reasons for conflicts between DG developers and grid operators are:

- lack of experience on the side of the DG developer and/ or grid operator,
- lack of understanding of the situation and the processes of the counterpart also because of lacking communication,
- disadvantages that grid operators have to suffer when DG plants are connected to the grid,
- lack of resources (in terms of staff and technology) for the communication with DG developers on the side of grid operators as these costs are not sufficiently reimbursed,
- lack of trust between plant operators and grid operators due to conflicts in the past.

In what follows some national aspects are also given.

Kosovo

- system operator may refuse to connect an applicant temporarily or permanently; this study suggests to use ancillary service instead (i.e. optimization of network capacity via improved consideration of DGs such as applied in Germany),
- sample PPA shall be drafted by the Public Supplier (approved from ERO) in order to increase security for RES investors (according to the current scheme, PPAs are signed only after the construction of RES plants, at the time of their commissioning, which makes project funding difficult),
- no simplified procedures are applied (either planned) for small scale DGs (e.g. solar panels in buildings).

Albania

- shall decrease the losses in the grid,
- secondary legislation is still missing,
- NEAP has not been adopted,
- the network operators have to increase transparency regarding connection and access to the grids,
- introduce feed-in tariffs for other technologies besides hydro,
- feed-in tariff changes every year; the formula of the selling price not a long term decision (offering base price for the energy for at least 15 years for small producers; creating a budget fund to pay small producers),
- shall define entity for managing RES imbalances,
- supply bottlenecks and demand imbalances constrain electricity supply and reduce the stability and reliability of the grid; load shedding, black-outs and electricity rationing are common across the country – grid investments are needed,
- Albanian Government is developing an off-take contract for small HPPs based on “take-or-pay” principle, which will guarantee the small power producers that in case of their curtailment by the network operator without a technical reason they will be compensated for the reduced output.

Bosnia and Herzegovina

Republic of Srpska

- Republic of Srpska was the first in the observed region that introduced net-metering by Renewable Law (2013); i.e. netting of electrical energy fed to and consumed from the distribution network (in 2015 net-metering was introduced in Croatia). However, responsible Ministry informed about administrative barriers that prevent implementation of net-metering support scheme. Indirect Taxation Authority provided obligatory opinion on these issues by which netting is prohibited, and invoices should be issued both for consumption and delivered generation. Although first customers are registered by regulatory authority in net-metering support scheme, there are issues (i.e. taxation, standards contracts) which must be resolved before the system becomes fully applicable,
- in comparison to the rest of the observed DSOs in the region, ERS web site (http://www.ers.ba/index.php?option=com_content&view=article&id=122%3Apodsticaj-proizvodnje-iz-obnovljivih-izvora&catid=17%3Anovosti&Itemid=66&lang=ba) contains rather comprehensive publically available practical guidelines on the connection procedure and standard contracts (connection contract, PPA contract during test operation (i.e. initial parallel operation), grid usage contract),
- by adoption in 2014 of *Rulebook defining the method, terms and conditions and procedure for connection to the distribution network of generation facilities which use renewable energy sources and efficient co-generation*, it could be considered that ERS advanced the most with regard of legal framework related to enactments of comprehensive technical criteria and connection requirements for distributed generation; it this sense it could serve as exemplar for the region,
- only RES and efficient co-generation producers under feed-in tariff are entitled to priority access in accordance to submitted daily schedule of operation; all other RES and efficient co-generation producers, even those entitled to premium for electricity sold at the electricity market, are not entitled to priority access,
- separate legal company shall be established acting as a renewable energy operator,
- simplified procedure for small DGs shall be developed (i.e. below 50 kW),
- cost sharing model for producers is used.

Federation entity (EPHZHB and EPBiH)

- limited information and no guidelines (brochures) on the web site; DSO have to increase transparency regarding connection and access to the grids,
- there is a lack of information for investors when it comes to the legal framework that regulates the field of renewable energy,
- Distribution Code is old (2008). It contains only limited number of provisions related to producers. There are no special provisions regarding RES,
- the “renewable energy operator” did not adopt standard PPA for privileged and qualified producers (as proposed in Article 26 and Article 20 of REL) (at least it is not publically available on the web site),
- although stipulated by primary legislation (REL), “priority connection” principle for RES is still not developed and included in by laws dealing with the connection to distribution network,
- renewable energy operator shall establish a methodology for allocating costs of balancing to the privileged and qualified producers and the also share of costs of balancing that will be covered by incentive fees collected from final customers
- REL (2013) envisages all RES to enjoy *priority in processing* request for connection to the distribution network in the Federation of Bosnia and Herzegovina; However, the Rulebook on methodology for setting the cost, terms and conditions of connection to the distribution network (2014) did not develop the "*priority in processing* " principle for RES.

Serbia

- in the forthcoming period the regulatory framework shall be defined with an aim to achieve maximum simplification of administrative and technical procedures for installation and commissioning of small RES-based plants, having installed power below 50 kW,
- in comparison to the rest of the observed DSOs in the region, on EPS DSO web site (http://www.elektrovojvodina.rs/sl/korisnicki_servis/Uputstvo-za-priklucenje-elektrane-na-distributivni-sistem-elektricne-energije), there are comprehensive guidelines and information related to the interconnection of distributed resources to distribution network. Besides guidelines, there are standard request forms related to connection procedure,
- new model of PPA for RES shall be adopted allowing investors greater certainty for investment in RES.

Croatia

- shall improve market functioning and the calculation of balancing costs caused by eligible producers and accordingly imbalance charges for eligible producers in the incentives system,
- after the expiration of the incentive period all privileged producers shall sell on the wholesale market (i.e. become market participant) or conclude contract with some supplier/trader on the market. Currently, there is a problem with small producers below 1 MW since no licence for electricity production is required for them, which is prerequisite for obtaining market participant status. So they shall find market participant willing to conclude a PPA with them, otherwise they shall be disconnected from the network by system operator. In this sense, it might be more convenient to appoint some supplier which shall have obligation to conclude (under certain conditions) PPA with small privileged producers whose production is not incentivised and which are not obliged to issue licence for electricity production (i.e. producers below 1 MW). Otherwise, DSO might be exposed to inconveniences related to the disconnecting such producers (including RES) from the network until they sign PPA,
- new Distribution Code is being drafted – current Distribution Code(2006) is deficient in addressing DGs and RES and efficient cogeneration,
- in Grid (Distribution) Code (March 2006) and General Conditions for grid Usage and Electricity Supply (2015), there are no explicit provisions providing for RES priority dispatching,
- simplified procedure for small DGs shall be developed (i.e. under 30 kW) (i.e. fast tracking & screening criteria in the connection procedure).

Macedonia

- NEAP has not been adopted; the 3rd energy package partial adopted,
- recent amendments to the Law on Urban and Spatial Planning and to the Law on Construction improved administrative procedures:
  - (for small HPP) shortened and facilitated the procedure for adoption of the urban plans (one of the most complicated and time consuming procedure),
  - possibility for applying for construction permit before the land titles issues are resolved,
  - application for connection to the grid can be initiated prior to obtaining the construction permit (shortening the procedure),
- considerable efforts have recently been made for introduction of more efficient and transparent grid connection procedure, primarily through amendments in Distribution Code,
- cost sharing model for producers,
- simplified connection procedure for small DGs shall be developed,
- further work on making more transparent connection procedure and charging has to continue.

In what follows also some additional recommendations are provided related to DG interconnection and operation in parallel with distribution system, based on international (primarily U.S.) practices applicable to SEE region.

Duration of connection process

Frequently investors are putting pressure on DSO due to rather lengthy connections procedure. However, the fact is that there are certain DSO activities are conditioned by other and aspects DSO could not control (i.e. unforeseeable problems), such as: approvals of administrative bodies, issuing permits, resolving property rights relations, on-site events, etc. This should be respected by investors. On the other hand DSO shall be obliged to timely communicate to network user on all adjournments and, if necessary, even to specify new deadline for connection, different technical option and deadline for connection, and/or to terminate grid connection contract. Most of the DSO in the region is trying to act accordingly.

Connection charging

Non uniformly determined charges for grid connection constitute a major barrier or at least a major cost component for the integration of DG plants into the existing grid.

Uniform rules for charging integration of DG into the distribution system have so far not been put into effect, as far as grid reinforcement costs are concerned and transparency concerning grid connection charging can still be raised. From the gird operators' point of view there are no incentives in place to remove existing bottlenecks for additional DG integration. The regulation in place does not endogenously reward investments facilitating additional DG deployment and securing quality of supply on behalf of network operators.

So far, no locational signals are implemented in the framework of electricity grid charges for generators. In order to transform variable side effects of new installations on the grid infrastructure, marginal costs of expected regional deployment of generation capacity may be attributed partly to generators (G-charge), partly to load (L), following a comprehensive planning attempt taking into account energy policy targets, RES potentials and energy infrastructure development. Publishing grid access contracts might increase transparency in the licensing process for new installations.

DSO revenues and incentives to integrate DG

The EU Electricity Directive (Article 25):

> *When planning the development of the distribution network, energy efficiency/demand-side management measures or **distributed generation** that might supplant the need to upgrade or replace electricity capacity shall be considered by the distribution system operator.*

stipulates that DG should be considered by DSOs when planning the development of the distribution network optimising the need for upgrading or replacing network capacity.

In order to implement in practice the Article 25 mandate, here are given recommendations which shall serve to improve network planning taking into account DG, to design regulatory arrangements for compensating extra costs incurred by DSOs due to DG, and to improve DSO performance in quality of service taking into account DG:

- Allowance for these extra costs in the Regulated Asset Base (RAB) are recommended for rate of return regimes,
- Incentive regulation based on price or revenue caps rather than rate of return regulation puts more pressure on DSOs for network efficient investment. Under incentive regulation, allocation of allowed investment budgets for the next regulatory period for individual DSOs is recommended. DSOs will be allowed to keep efficiency gains, for more than one regulatory period, due to efficient integration of DG, as incremental profits.
- It is recommended to implement use-of-system charges (UoS) for DG and/or support mechanisms applied to DG, differentiated by time of use and voltage levels (e.g. DG production at load peak hours should be incentivised), together with economic incentives to DG for providing ancillary services to help DSOs to operate the network, with a more active management of the network by DSOs. This will

lead to a better optimization of the use of existing facilities, minimizing the requirement for new installations.
- The revision of planning and security criteria used by DSOs in order to include the potential benefit of DG deferring or reducing network investments is recommended (Germany and UK can be examples to follow).

It is recommended that the specific regulatory mechanism to compensate DSOs for incremental CAPEX & OPEX due to DG, should be designed taking into account the particular DSO regulatory framework in each country.

As observed in [24], DSOs with distribution areas with high DG penetration/concentration levels could be compensated for incremental energy losses. For instance, a DSO revenue driver, in €/kWh, associated with DG production (kWh) located in those areas can be implemented. This compensation would mainly come from those generators connected in those areas that would be charged with a fee (€/kWh) proportional to the value of the incremental losses they produce in the network. On the other hand, it is recommended to implement use-of system charges for DG and/or support mechanisms applied to DG, differentiated by voltage levels, to take into account that DG connected in lower voltage networks can reduce losses at higher voltage levels.

Network and ancillary services

The potential advantages of having DG as a new control source should become a DSO opportunity instead of a threat. DG can provide ancillary services such as voltage control, frequency reserve, or black start to improve voltage quality. To achieve this aim, it is recommended to implement:

- performance based regulation for quality of service targets that provides explicit incentives to DSOs for improving quality of service levels,
- incentives for DSO innovation programs that promote a deep transformation from passive to active management increasing DG participation in network control and DG contribution in case of network disturbances,
- incentives to DG for providing ancillary services to help DSOs to operate the network, for instance, providing voltage control and reactive power support, congestion management, islanding operation, etc. to improve quality of service levels.

DG through aggregators can participate in balancing and reserve markets.

Commercial arrangements between TSO/DSO and DG to recognize such contribution can be:

- regulated payments to DG, for instance acknowledged in the UoS charges,
- bilateral contracts between DG and DSO,
- DG participation in markets: i) energy balancing and reserve markets; and ii) network related markets, such as local balancing, reactive power, congestion management, or energy losses compensation.

Balancing responsibility

In almost all countries preferential producers are not charged for their imbalance. If balancing responsibility lies within the single buyer of RES and is covered by the promotion scheme in place (e.g. in Croatia up until recently), this allocation does not provide any incentives for generators to efficiently plan and also place their production on electricity markets.

Observed countries shall bring their support schemes and balancing responsibility requirements in line with the EEAG [26].

RES Directive obligations and tendering of grid connection work

The European RES directive [7] mentions the options for member states to implement provisions requiring the socialisation of RES system integration costs and allowing RES producers to issue a call for tender for the connection work.

> *Member States may allow producers of electricity from RES wishing to be connected to the grid to issue a call for tender for the connection work.*

Option of tendering is put into force only in Serbia; in accordance to RES Directive, developers are entitled to build the connection to the grid, calling for a tendering for construction works if they choose so. They have the right to deduct the respective cost of construction from the total connection costs that are calculated in accordance with a methodology adopted by AERS (regulatory authority).

In other countries the right of issuing a call for tender for the grid connection work is not mentioned in respective regulations. But if the work on own account has to be accounted for, this option seems to be open in principle.

Priority and guaranteed access for RES

With regard of priority and guaranteed access, even though in some countries primary legislation principle provisions were introduced, implementation details are left the to secondary legislation. In other words, „priority" obligations have not been transposed into the secondary legislation like grid codes.

According to the Article 16 of RES Directive, if significant curtailment of RES, in order to guarantee the security of system and energy supply, occurred DSO shall report to regulator on:

- those measures (curtailment),
- indicate which corrective measures they intend to take in order to prevent inappropriate curtailments.

In the observed DSOs such activates, either obligations for DSO and RA, are not performed either adequately enacted.

Towards Smart grids

Major deficiency of the existing control system is that a significant number of distribution facilities is not integrated into these systems, and that should be the priority within the development of this system, as a prerequisite for introduction of intelligent grids, along with the introduction of advanced meters at network users.

Incentives to promote DSO innovation for efficient integration of DG should be incorporated into network regulation. Some of the instruments can be:

- R&D investments can be included in the RAB as a separate item with higher rates of return or with a partial pass-through. (An example is the Innovation Funding Incentive (IFI) in UK. A DSO is allowed to spend up to 0,5% of its revenue on eligible IFI projects).
- Selection of performance indicators that can be improved through network innovation.
- Regulators may work with DSOs formulating and testing new regulatory instruments, and developing new regulatory scenarios with a shared vision, in order to explore deeper and long-term network transformations.
- The selection of the most appropriate instruments in each country would take into account the type of DSO incentive regulation in place and the national regulatory framework.

Streamlining and simplification of administrative and technical procedures

In the forthcoming period the regulatory framework shall be defined with an aim to achieve maximum simplification of administrative and technical procedures for installation and commissioning of small RES-based plants, having installed power below 30-50 kW, and owned primarily by natural persons. Particular attention shall be dedicated to the accessibility of information to natural persons interested in small PP (i.e. solar panels).

In this regard, the study recommends:

- Improved access to information about distribution system conditions at points of interconnection that enable applicants to self-screen projects in a manner that reduces applications for interconnections in certain areas.
- Introduction of fast track technical screens to accommodate small generators interconnections (certain work in SEE DSO already can be observed; e.g. 30 kW limit in Croatia, 23 kW limit in EPHZHB and EPBiH, 50 kW limit in EPS and ERS).
- Increased efficiency in the application process for very small, certified inverter-based systems that pose a low likelihood of adverse system impacts of the sort that require extensive study.
- Inform publically all potential investors on the available hosting capacity of the networks.

In this regard SEE DSO shall benefit from best practices and lessons learned through this project from the U.S. experience in reforming interconnection processes in light of changed market conditions. In this study, special focus has been given on simplified screening criteria used in U.S. DSOs (section 7.1) and worldwide (section 7.5), e.g. based on generation to load or short circuit contribution ratios, which are used as fast and simple first-step procedures when conducting interconnection feasibility studies.

This study recommends SEE DSOs to consider IEEE 1547.7-2013 which provides good practices for engineering studies of the potential impacts of a distributed resources or aggregate distributed resources interconnected to the distribution system. This IEEE guide describes criteria, scope, and extent for those engineering studies. Study scope and extent are described as functions of identifiable characteristics of the DR, the EPS, and the interconnection. The intent includes promoting impact study consistency while helping identify only those studies that should be performed based on technically transparent criteria for the DR interconnection.

As to processing the application for interconnection is delicate issue, this study recommends SEE DSOs to designate an employee or office to provide the applicant with information on the requirements for the utilities' application review process.

Transparency and publicity

All DSOs in the region are obligated to prepare a distribution system development plan for the period od minimum ten years, harmonized with the plan of development of transmission systems and requirements for the connection of producer and also customer facilities. However, these plans are rarely publically available and also serve as not so reliable source of data for producers regarding the available hosting capacity of the networks for connection of new producers.

DSOs shall inform publically potential investors on the available hosting capacity of the networks. In this way, investors are assisted to make preliminary decisions regarding project placement and sizing. It is important to stress that tools and methods used for the assessment of the available capacity do not substitute grid connection study (assessment). Some DSOs worldwide already adopted such approach (see section 7.7).

Additionally, a comprehensive description of the whole connection procedure or (updated regularly) guidance for investors in local language and English is recommended.

Work-relationship between DSO and DG

The research at national level in EU has shown that communication problems and conflicts between grid operators and plant operators aggravated the grid connection process [23]. Such conflicts had a negative impact on the connection process of the DG plants because they reduced flow of information and delayed the overall process. In this context, it also turned out that legal regulation helped only to some extent. To improve the framework of the work-relationship between the two parties priority should be given to measures which aim to improve the communication between grid operators and plant operators and ensure that experience of good cooperation will be disseminated on both sides. One way to achieve this goal would be to establish a regular platform of communication between plant operators and grid operators.

To give an example, a first step into this direction has been taken in Germany with the establishment of the so called *Forum Netzintegration*. Stakeholders from the energy sector are meeting on a regular basis in order to identify main barriers for the development of the grid and to find and formulate possible solutions. At the end of the process, the *Forum Netzintegration* published the *Plan N*, which formulates the main findings of that discussion. In this process an exchange of ideas and perspectives is taking place that helps to improve the relationship between plant operators and grid operators in general.

Another example could be the *Electricity Network Strategy Group* in Great Britain, fulfilling a similar purpose. It helps to choose two representatives in each group to collaborate on a continuous base, setting a direct link to discuss problems as soon as they come up. Such a close co-operation between grid operators and RES industry would mean that both groups had to provide additional funding for the necessary resources in terms of people and organization. These investments, on the other hand, would make sure that the process would be organized in an effective and efficient way.

This approach will certainly not solve all conflicts between different parties, bearing in mind that conflicts are often simply originated by contradicting interests. Still, this approach may prevent unnecessary conflicts that are caused by lack of trust and communication. In these cases, cooperative actions will help parties to find solutions that serve their common interests.

It could be observed that even in the U.S. states are constantly examining their interconnection policies and procedures to ensure that these are aligned with their overall renewable energy goals and policies states. More and more states run into challenges stemming from outdated interconnection standards. As with all standards, interconnection processes are constantly evolving and changing, particularly as demand for renewable energy grows, penetration increases, and as technologies and protocols evolve. In this sense, reviewing U.S. efforts, issues and barriers to interconnection, can assist SEE DSOs while developing their interconnection rules. With theirs clear explanations of the major interconnection issues and discussions of how states have addressed those issues, *Freeing the Grid* and *DSIRE* are an invaluable resources for DSO and regulatory authority staff facing the daunting task of creating or revising interconnection procedures.

New technologies and standards will impact DG interconnection in the future. Manufacturing of better inverters, smart grid deployments, and new standards are already underway. Continual revisions of interconnection rules should lead to easier interconnection and allow additional distributed generation to be interconnected in an expedited fashion without having to perform detailed impact studies. However, potential owners of distributed generation also need to realize that they cannot be connected anywhere on the electric grid without causing system impacts (costs). In some cases, even small systems will cause impacts, require impact studies, and require the utility to install additional facilities or change operating practices to accommodate the new distributed generation. The greatest challenge is to accomplish (through development of regulatory framework) that DGs have incentive to become beneficial for the system.

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10 APPENDIX I: QUESTIONNAIRE

1. **What is number and installed capacity by technologies of distributed generation in your distribution system (preferable as of 31.12.2014 – please specify if otherwise):**

   a. **In operation:**

Technology of power plants	MV / LV*	Number of plants	Total installed capacity (MW)	Largest plant installed capacity (MW)	Smallest plant installed capacity (MW)
Wind power plants	MV				
	LV				
Solar plants	MV				
	LV				
Hydro power plants	MV				
	LV				
Biogas power plants	MV				
	LV				
Biomass power plants	MV				
	LV				
Other (specify)	MV				
	LV				

** MV means voltages from 1 kV to 35 kV, LV means voltage below 1 kV*

   b. **Under construction:**

Technology of power plants	MV / LV*	Number of plants	Total installed capacity (MW)	Largest plant installed capacity (MW)	Smallest plant installed capacity (MW)
Wind power plants	MV				
	LV				
Solar plants	MV				
	LV				
Hydro power plants	MV				
	LV				
Biogas power plants	MV				
	LV				
Biomass power plants	MV				
	LV				
Other (specify)	MV				
	LV				

** MV means voltages from 1 kV to 35 kV, LV means voltage below 1 kV*

c. **With issued connection consent, but not yet in operation or under construction:**

Technology of power plants	MV / LV*	Number of plants	Total installed capacity (MW)	Largest plant installed capacity (MW)	Smallest plant installed capacity (MW)
Wind power plants	MV				
	LV				
Solar plants	MV				
	LV				
Hydro power plants	MV				
	LV				
Biogas power plants	MV				
	LV				
Biomass power plants	MV				
	LV				
Other (specify)	MV				
	LV				

** MV means voltages from 1 kV to 35 kV, LV means voltage below 1 kV*

2. **Specify legislative framework relevant for DG connection procedure:**
   a. **Primary legislation** (laws):

   ____

   ____

   b. **Secondary legislation** (by-laws):

   ____

   ____

   c. **DSO Internal acts:**

   ____

   ____

3. **Describe formal steps in DG connection process:**

   ____

   ____

   ____

   ____

4. What do you see as inadequacies and bottlenecks in existing DG connection legislative framework?

____

____

____

____

5. What kinds of analyses are performed in the DG connection process (if necessary differentiate by voltage levels and DG types)?

a. Steady-state load flow analysis
b. Reactive power and voltage control analysis
c. Short circuit analysis
d. Dynamic analysis
e. Impact on network losses
f. Power quality analysis
g. Protection setting elaboration
h. DG contribution to the ancillary services
i. Island operation of DG
j. Harmonics analysis
k. Other (specify):

____

____

Is there software (more or less officially) used in DSO for such analyses?

____

____

6. Who is in charge for above mentioned analyses?

a. DSO
b. Investor
c. Other (specify):

____

7. **Who is financing above mentioned analyses?**
   a. **DSO (it is part of network fee)**
   b. **Investor (it is part of connection charge)**
   c. **Investor (it is paid aside of connection charge)**
   d. **Other (specify):**

      ____

8. **What is the most frequent technical limitation in DG connection process?**
   a. **Network element loading**
   b. **Voltage variations/drops**
   c. **Short circuit level**
   d. **Network loss increase**
   e. **Power quality issues**
   f. **Protection setting problems**
   g. **Harmonics**
   h. **Other (specify):**

      ____

9. **Are there any formal connection requirements that the DSO places on DGs related to voltage variations/drops in DG connection point?**
   a. **yes (specify):**

      ____

      ____

   b. **no**
   c. **Other (specify):**

      ____

10. **Are there any formal connection requirements that the DSO places on DGs related to network loss increase due to DG operation?**
    a. **yes (specify):**____
    b. **no**
    c. **Other (specify):**

       ____

11. What is the average time needed from connection application till DSO issues connection consent?

- **a. More than 6 months**
- **b. 2 – 6 months**
- **c. Less than 2 months**
- **d. Other (specify):**

____

12. What is the validity of DG connection consent?

- **a. 1 year**
- **b. 2 years**
- **c. 4 years**
- **d. unlimited**
- **e. Other (specify):**

____

13. What is the most often reason for DG connection request denial?

- **a. Inadequate analysis**
- **b. Non-payment of connection charge**
- **c. Technical limitation in the network**
- **d. Other (specify):**

____

14. What is DG connection cost sharing model in your DSO?

- **a. Deep** (investor is charged full cost of its connection and needed existing network reinforcements)

____

- **b. Shallow** (investor is charged full cost of its connection only, while needed existing network reinforcements are covered by the DSO)

____

- **c. Shallowish** (investor is charged full cost of its connection and percentage of needed existing network reinforcements according to DG share of capacity)

____

- **d. Other** (specify the details):

____

15. Are there any DG unit connection cost?

a. **Yes, for specific capacities (specify):**

____

b. **No, it is individually calculated**

c. **Other (specify):**

____

16. How many contracts between DG investor and DSO are to be signed in the connection process?

a. **One (i.e. connection contract)**

b. **Two (i.e. connection contract and network use contract)**

c. **More (specify):**

____

17. Who is the owner of the relevant metering device?

a. **DSO**

b. **Investor**

c. **Other (specify):**

____

18. Which part of installed DG capacity is subsidized (in feed-in or premium or other incentive system) (preferable as of 31.12.2014 – please specify if otherwise)?

Technology of power plants	MV / LV*	Number of plants	Total installed capacity (MW)	Largest plant installed capacity (MW)	Smallest plant installed capacity (MW)
Wind power plants	MV				
	LV				
Solar plants	MV				
	LV				
Hydro power plants	MV				
	LV				
Biogas power plants	MV				
	LV				
Biomass power plants	MV				
	LV				
Other (specify)	MV				
	LV				

** MV means voltages from 1 kV to 35 kV, LV means voltage below 1 kV*

19. Are there any limitations in total quota of DG installed capacity?

  a. **yes (specify, e.g. by technology, installed power, connection voltage,…)**

  ____

  b. **no**

20. Are DGs obliged to submit its (hourly, or 15 minutes) generation/production plans to the DSO or market operator?

  a. **yes**

  b. **no**

  c. **Other (specify, e.g. by technology, installed power, connection voltage,…)**

  ____

If yes, when?

  ____

21. Are DGs financially responsible for imbalances (deviation between planned and realized generation output)?

  a. **yes**

  b. **no**

  c. **Other (specify, e.g. by technology, installed power, connection voltage,…)**

  ____

22. Did you experience any unexpected system operational problems due to DG connection?

  a. **yes (specify):**

  ____

  b. **no**

23. Is DSO/TSO allowed to limit DG output in the case of jeopardized security of supply or network congestions?

  a. **yes (specify):**

  ____

  b. **no**

24. If DSO is allowed to limit DG output in the case of jeopardized security of supply, is DSO obliged to prove/explain the reasons a posterior?

a. yes (specify the details):

____

b. No

25. If DSO is allowed to limit DG output in the case of jeopardized security of supply, is DSO obliged to compensate to DG for loss of income from energy sales?

a. yes (specify the details):

____

b. No

26. Do DGs provide (i.e. is it envisaged by bylaws) ancillary services to DSO or TSO?

a. yes (specify which services):

____

b. no

27. Who can or must purchase electricity produced in DGs? Please describe and specify the price.

____

____

____

____

28. What is the price of DG output in comparison to other conventional generation or electricity import (i.e. wholesale DG output price for suppliers or total DG revenue by MWh generated)?

Technology of power plants	Voltage level	€/MWh
Wind power plants	MV	
	LV	
Solar plants	MV	
	LV	
Hydro power plants	MV	
	LV	
Biogas power plants	MV	
	LV	
Biomass power plants	MV	
	LV	
Other (specify)	MV	
	LV	
Total		

** MV means voltages from 1 kV to 35 kV, LV means voltage below 1 kV*

11 APPENDIX II: REQUESTED CLARIFICATIONS AND ADDITIONAL QUESTIONS

1 (EDB) Please explain in more detail DG connection cost sharing model in your DSO, and comment whether is satisfactory for DSO and investors.

2 (EDB) If possible, please provide more detailed answer to question no. 15: "*Are there any DG unit connection cost?*"

3 (ERS) With regard of analyses performed in the DG connection process, are there any differences between LV and MV DGs applications? Are these analyses equally extensive, or there are some differences (if "yes", please explain)?

4 (ERS) To Q21 "*Are DGs financially responsible for imbalances (deviation between planned and realized generation* output?", your answer was positive. Could you please explain in more detail how in Republika Srpska DGs bear financial responsibility for imbalances?

5 (EPHZHB) Please explain, how making of grid connection study (EOTRP) depends on DGs size?

6 (EPHZHB) To Q9 "*formal connection requirements that the DSO places on DGs related to voltage variations/drops in DG connection point*", your answer was 2 %. Is this 2 % limit prescribed by some bylaw or DSO internal act? If "yes", please specify the act.

7 (EPHZHB) Related to answer to Q15, could you please specify DGs for which indicated unit prices apply.

8 (EPHZHB) Related to answer to Q19 "*Are there any limitations in total quota of DG installed capacity*" could you please elaborate in more detail about the limits.

9 (EPHZHB) To Q21 "*Are DGs financially responsible for imbalances (deviation between planned and realized generation* output?", your answer was positive. Could you please explain in more detail how DGs bear financial responsibility for imbalances?

10 (EPBiH) Are those internal DSO acts indicated in your answer to Q2 publically available? For example:

   a. *Procedura kojom se propisuje postupak izdavanje prethodne elektroenergetske saglasnosti za krajnje kupce i proizvođače TP 72/05, zajedno sa prilozima".*
   b. *Procedura kojom se propisuje postupak provjere kolizije i zaštita/izmještanje elektrodistributivnih objekata PD 72/06, zajedno sa prilozima,*
   c. *Procedura kojom se propisuje postupak izdavanje elektroenergetske saglasnosti za krajnje kupce i proizvođače TP 72/07, zajedno sa prilozima,*
   d. *Procedura kojom se propisuje postupak priključenja krajnjih kupaca i proizvođače na distributivnu mrežu TP 75/01, zajedno sa prilozima,*
   e. *Proceduru kojom se propisuje postupak ustanovljenja prekoračenja odobrene priključne snage i regulisanje isporuke električne energije u novim uslovima TP 72/02, zajedno sa prilozima.*

11 (EPBiH) Related to your answer to Q9 "*formal connection requirements that the DSO places on DGs related to voltage variations/drops in DG connection point*", please elaborate in more detail how limit on reactive energy production/consumption and other technical limits (mentioned in your answer) are used with regard to voltage variations/drops?

12 (EPBiH) Related to your answer to Q21, does it mean that owners of DGs will participate in balance mechanism (borne some part of imbalance costs) or total imbalance costs will be covered by fees for the promotion of electricity generation from renewable sources?

13 (EPBiH) Related to your answer to Q23, "*DSO/TSO is not allowed to limit DG output in the case of jeopardized security of supply or network congestions*", please specify in which act is this stipulated?

14 (EPS) Please elaborate the relevance of "*JP Elektroprivreda Srbije, Tehnička preporuka br.16, Osnovni tehnički zahtevi za priključenje malih elektrana na mrežu Elektrodistribucije Srbije, I izdanje, Beograd, 2003.*" for the connection of DGs to distribution systems in Serbia.

15 (EPS) Related to answer to Q19, please specify quotas for wind power plants and solar power plants, and how they were determined?

16 (EPS) Related to answer to Q20 please clarify how DG meter readings form are used in balance mechanism?
17 (EPS) Related to answer to Q22 if possible please explain in more detail why constant power factor resulted with disconnection of DGs from distribution system ?
18 (HEP) Related to answer to Q5b if possible please indicate which software is officially used in DSO for DG connection analyses.
19 (HEP) Related to your answer to Q23, "*DSO/TSO is not allowed to limit DG output in the case of jeopardized security of supply or network congestions*", please specify in which act is this stipulated?
20 (EVNM) Are those internal DSO acts indicated in your answer to Q2 publically available?
21 (EVNM) Related to answer to Q5b if possible please indicate which software is officially used in DSO for DG connection analyses.
22 (EVNM) Related to answer to Q6 if possible please clarify what is the purpose of investor made analyses (based on data received from DSO). How are these treated by DSO?
23 (EVNM) Related to your answer to Q21, if "preferential" producers are exempt from participating in costs of balancing the power system, how these costs are covered? What is the purpose of hourly plans (see Q20) that DGs are submitting on the electricity market (besides for system operation planning made by TSO)?
24 (OSHEE) Please explain why there no existing and planned power plants on LV level?
25 (OSHEE) Are there any publically available documents that describe connection procedure and criteria and in this sense help DG investors willing to connect to distribution system?
26 (OSHEE) Related to your answer to Q17, "*Who is the owner of the relevant metering device?*", you indicated "KESH and the buyers". Please explain when are the buyers and when KESH the owner of metering device.
27 (KEDS) Please specify connection voltage of two newly planned wind power plants with installed capacity 56,1 MW and 32,5 MW.
28 (KEDS) Please could you specify whether all newly planned 12 planned hydro power plants (with total installed capacity 77,47 MW) will be connected to voltages below 35 kV?
29 (KEDS) Please explain why there no existing and planned power plants on LV level?
30 (KEDS) Related to answer to Q19 "*Are there any limitations in total quota of DG installed capacity*" could you please clarify are there any technical limits (not limits on subsidizing) in the system with regards connection of DGs? For example, some countries in the region use technical limits for wind power plants due to their intermittent production and impact on operational reserves they require in the system.
31 (KEDS) To Q21 "*Are DGs financially responsible for imbalances (deviation between planned and realized generation* output?", your answer was positive for DGs over 5 MW. Could you please explain in more detail how DGs bear financial responsibility for imbalances?
32 (KEDS) Related to your answer to Q23, "*DSO/TSO is not allowed to limit DG output in the case of jeopardized security of supply or network congestions*", please specify in which act is this stipulated?
33 (KEDS) Please specify who must buy electricity produced by DGs (Q27).
34 (all DSOs) If possible provide flowchart depicting all steps in the connection procedure for DGs.
35 (all DSOs) If applied in your system, please comment pros and cons of unlimited validity of consent for connection once the investor started the construction works.
36 (all DSOs) Are there any publically available practical guidelines on DSO website that explain connection procedure to applicants/DG investors, deadlines, conditions, and so on. Do you deem information publically available transparent and informative enough?
37 (all DSOs) Are there, already used in practice or envisaged in the future, so called simplified procedures for connection of smaller DGs up (i.e. until certain size)? If "yes", please indicate size limit and also report simplifications adopted/envisaged.