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Short Term High Quality Studies to Support Activities under the Eastern Partnership

HIQSTEP PROJECT

STUDY ON THE EFFECT OF THE PLACEMENT OF SOLAR PANELS ON BUILDINGS TO INCREASE ENERGY SECURITY AND ENERGY EFFICIENCY AND DEVELOP CLEAN ENERGY IN THE EASTERN PARTNERSHIP COUNTRIES

Component 4 Report:
Programme Development for Building-PVs Based on a Cost - Benefit Analysis: Georgia

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List of abbreviations

AM	Armenia
ANRE	The National Regulatory Authority for Energy in Moldova
AREA	Azerbaijan State Agency on Alternative and Renewable Energy Sources
AZ	Azerbaijan
BY	Belarus
CBA	Cost Benefit Analysis
CEER	Council of European Energy Regulators
DANIDA	Danish International Development Agency
DGPV	Distributed Generation from Photovoltaics
DISCO	Distribution Company
DSO	Distribution System Operator
EaP	Eastern Partnership
EBGL	Electricity Balancing Guideline
EC	European Commission
ECT	Energy Community Treaty
ESCO	Electricity System Commercial Operator of Georgia
EU	European Union
EUD	EU Delegation
FiP	Feed in Premium
FiT	Feed in Tariff
GE	Georgia
GEDF	Georgian Energy Development Fund
GWNERC	Georgian Water and Energy Regulatory Commission
HiQSTEP	Short term high quality studies to support activities under the Eastern Partnership
IRR	Internal Rate of Return
LCOE	Levelised Cost of Energy
MD	Moldova
MS	Member State
NEURC	National Energy and Utilities Regulatory Commission of Ukraine
NM	Net Metering
NM	Net Metering
PSRC	Public Services Regulatory Commission of the Republic of Armenia
PV	Photovoltaic(s)
R2E2	Armenia Renewable Resources and Energy Efficiency Fund
RES	Renewable Energy Sources
ROO	Renewable Obligation Order
SAEEE	State Agency on Energy Efficiency and Energy Saving of Ukraine
SPE	Solar Power Europe
STL	Study Team Leader
T&D	Transmission and Distribution
TOR	Terms of Reference
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UA	Ukraine
VRE	Variable Renewable Electricity
WACC	Weighted Average Cost of Capital

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Preamble

The present report is a deliverable of the “Study of the Effect of the Placement of Solar PVs on Buildings in the EaP Countries” carried in the framework of the EU-funded project “High Quality Studies to Support Activities under the Eastern Partnership - HiQSTEP” (EuropeAid/132574/C/SER/Multi). The study covers all six Eastern Partner Countries, namely Armenia, Azerbaijan, Belarus, Georgia, Moldova and Ukraine.
The overall objective of the study is to address the effect of the placement of solar panels on buildings in Eastern Partner countries for the purpose of increasing energy security and energy efficiency and developing clean energy sources.

The specific objectives of the study are the following:

- To present EU policies, rules, regulations, tools and schemes towards the promotion of solar panels on buildings;
- To assess existing policies, rules, regulations and tools towards promotion of solar panels on buildings in the six Eastern Partner countries;
- To develop cost-benefit analysis for the staged development of building PVs in all Eastern Partner countries;
- To formulate recommendations on how to enhance PV penetration in the six Eastern Partners;
- To quantify the impact of building PV penetration to the overall energy mix and on the energy security of each country and to quantify the impact of PV generated energy to greenhouse gas emission reduction.

The present Study was implemented by a Study Team headed by Mr. Nikos Tourlis, Study Team Leader and composed of:
Mr. Vassilis Papandreou – Energy Expert, Coordinator of Component 1
Mr. Matteo Leonardi – Energy Expert, Coordinator of Component 2
Prof. Agis Papadopoulos – Solar Energy Expert, Coordinator of Component 3
Prof. Petros Patias - Rural and Surveying Engineering Expert
Ms. Chiara Candelise – Energy Expert, Coordinator of Components 4 & 5
Mr. Nikos Tourlis - Grid Expert
Mr. Armen Gharibyan - Local Energy Expert Armenia
Mr. Jahangir Efandiyev - Local Energy Expert Azerbaijan
Mr. Andrei Malochka - Local Energy Expert Belarus
Ms. Nino Maghradze – Local Energy Expert Georgia
Mr. Andrei Sula – Local Energy Expert Moldova
Mr. Kostiantyn Gura - Local Energy Expert Ukraine
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- The Ministry of Energy and Natural Resources of Armenia, represented by Mr. Tigran Melkonyan;

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- The Department of Energy Efficiency in National Standardisation Authority of Belarus, represented by Mr. Andrey Minekov and Mr. Vladimir Shevchenok;
- The Ministry of Energy of Georgia, represented by Ms. Margalita Arabidze and Ms. Natali Jamburia;
- The Ministry of Economy of Moldova, represented by Mr. Denis Tumuruc;
- The State Agency for Energy Efficiency of Ukraine (SAEE), represented by Mr. Sergeiy Savchuk;

1 Introduction

The aim of this fourth component of the solar power in buildings study, is to develop and undertake a cost benefit analysis of different scenarios, allowing for a staged building-PVs installation programme, accounting for different levels of PV penetration and policy support.

The analysis undertaken in the “Review of Eastern Partner Countries experience with building-PVs” (Component 2) report of this study has concluded, that the situation current in Georgia with respect to energy services, RES and (in particular) PV markets is still in the very early stages of its development. Georgia hasn’t developed to date a robust legislative and regulatory framework in order to promote RES, in particular PV technologies. Hence, the PV market in Georgia is currently very limited: very few PV installations exist and have either been implemented by means of international financing (through grants or IFI-led financing facilities or a combination of the two) or out of the spontaneous response of few private parties after the introduction of the Net Metering regulation in 2016.

Moreover, the gap analysis in the “Review of Eastern Partner Countries experience with building-PVs” (Component 2) report of this study has highlighted that the current framework for RES systems is cumbersome and not particularly favourable for the development of distributed generation, taking also into account the fact that the Net Metering regulation is actually strongly hampered by the prevailing low electricity prices. Nevertheless, its recent accession to the Energy Community Treaty will necessitate Georgia to adopt a more favourable RES legislation and, within that, specific policy support programmes tailored on building-PV deployment could, and should, be implemented. The electricity market structure does not represent a barrier for PV rooftop development and it is generally compatible with such a goal, given that distributed generation is not considered an effectively competitive segment of the market. In this context, a streamlined programme for the development of building-PVs would make sense as it could serve as a pilot in order to provide the specific market with the necessary momentum. More specifically, it would allow PV technology to take-off, the system’s cost to be reduced and a value chain to be created, owing to a steady, foreseeable and progressive deployment, market expansion and learning procedure.

As previously mentioned, the purpose of this report is to analyse and assess the level at which building-PV deployment could accrue in the years to come in Georgia and under which policy and regulatory conditions this can happen. It firstly develops building-PV penetration scenarios based on the “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” (Component 3) report of this study. Those deployment scenarios are associated with the implementation of a building-PV specific policy support, in the form of either capital grant or FIT scheme. A detailed cost and benefits analysis of the implementation of the deployment scenarios, is then undertaken in relation with increasing levels of PV policy support, to provide evidence for supporting any future policy decisions. In detail, this report is structured as follows:

Section 3 sets the context of the cost benefit analysis by defining the target market segments and by developing scenarios for building-PV deployment, associated with a progressive introduction of PV policy support measures, in particular:

- Section 3.1 takes outcomes of the “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” (Component 3) report of this study,

in terms of potential PV capacity on buildings, as the starting point to develop scenarios for building-PV deployment at both Georgian cities and national aggregated level;
- Section 3.2 defines targets for the market segments, based on evidence of installation patterns in other EU countries, which experienced a documented, successful PV market uptake;
- Section 3.3 briefly reviews the Georgian RES and PV policy framework and the market development, based on the information provided by the "Review of Eastern Partner Countries experience with building-PVs" report of this study, makes the case for the introduction of building-PV policy support and presents the policy options available;
- Section 3.4 finally builds up building-PV deployment scenarios and combines them with a progressive introduction of policy support tools. These scenarios constitute the basis and reference for both end users and cost-benefits analysis in the following sections.

Section 4 presents assumptions, data and results of the end user analysis, which essentially comprises an investment appraisal of building-PV systems, aimed at understanding the economics of current building-PV policy framework and at estimating the level of policy support that would be needed in Georgia, in order to properly incentivise building-PV investments and their uptake.

Section 5 presents respectively assumptions, data and results of the cost and benefit analysis of the policy measures assumed under the different building-PV deployment scenarios, accounting for both the cost of policy (both at an aggregate system's level and in terms of its impact on electricity consumers) and the quantifiable benefits accruing from the implementation of building-PV capacity in the country. A discussion on options to finance the deployment programmes is also presented in this section.

Section 6 presents a qualitative discussion on the possible impact of increased penetration of building-PV on the grid and its possible implications for the Georgian electricity system.

Section 7, finally, concludes and provides final recommendations on next steps for the deployment of building-PV sector in Georgia.

2 Defining building-PV deployment scenarios for cost benefit analysis

This section sets the context for cost benefit analysis of staged deployment of building-PV in Georgia. It defines staged building-PV deployment scenarios, based on total PV capacity potential, as this has been estimated in the "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study. On the premises of a clear definition of building-PV market segments, this section also builds on the rationale of progressive introduction of PV policy measures, tailored to the current Georgian RES and PV market situation. Ultimately, the goal of the analysis presented in this section is to define the foreseeable scenarios based on which the expansion of the national building-PV market may be anticipated.

2.1 Defining total building-PV capacity potential

In order to build up staged building-PV deployment scenarios for Georgia, the total installation potential for buildings in major Georgian cities needs to be taken into account, at least as an upper limit of possible deployment. In this line of approach, we take the outcomes of the “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” report of this study in terms of potential PV capacity on buildings as the starting point to develop scenarios for building-PV deployment. This potential has been estimated, in terms of MWp of rooftop PV systems which can be installed on suitable building roofs, for the following four Georgian cities: Tbilisi, Batumi, Kutaisi and Rustavi. Based on the findings of the “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” report of this study the building stock of Georgian cities can be classified in two main typologies (Table 1):

- Single family houses, characterised by sloped roofs;
- Large buildings, both residential and commercial ones (including public), characterized by flat roofs.

For each of the two types of buildings the PV installation potential is estimated taking into consideration:

- Available rooftop area: areas which are free from roof elements and obstacles and not needed for maintenance work (i.e. 90% for sloped roofs, 60% for flat roofs)
- Solar suitability coefficient: the fraction of the available rooftop area in which PV system can produce at the maximum efficiency (higher for flat roofs than sloped roofs, as the former makes it easier to design the system optimizing orientation and inclination).

The analytical determination of the PV potential was carried out in the “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” report of this study, by means of a surface-based evaluation method, followed by a multi-constraint installation capacity assessment. Still, as there were no field studies’ data to use for the extrapolation and the validation, this was done based (a) on the information obtained by the local experts and also during our field-visits and (b) on relevant literature. A series of studies has been conducted, in various parts of the world, assessing the total rooftop area available for PV deployment[1].

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[1] L.Bergamasco, P.Asinari, Scalable methodology for the photovoltaic solar energy
potential assessment based on available roof surface area: Application to Piedmont Region (Italy), Solar Energy 85 (2011) 1041–1055

K.Mainzer, S.Killinger, R.McKenna..W.Fichtner. Assessment of rooftop photovoltaic potentials at the urban level using publicly available geodata and image recognition techniques, Solar Energy 155 (2017) 561–573

M.S.Wong et al., Estimation of Hong Kong’s solar energy potential using GIS and remote sensing technologies, Renewable Energy 99 (2016) 325e335

S.Izquierdo, M.Rodrigues, N.Fueyo, A method for estimating the geographical distribution of the available roof surface area for large-scale photovoltaic energy-potential evaluations, Solar Energy 82 (2008) 929–939

J.Khan, M. Hassan Arsalan, Estimation of rooftop solar photovoltaic potential using geo-spatial techniques: A perspective from planned neighborhood of Karachi, Pakistan, Renewable Energy 90 (2016) 188-203

Theodoridou I., Karteris M., Mallinis G., Papadopoulos A.M. and Hegger M., Assessment of retrofitting measures and solar systems' potential in urban areas using Geographical Information Systems: application to a Mediterranean city, Renewable & Sustainable Energy Reviews (2012), 16, 6239–6261

Karteris M., Slini T. and Papadopoulos A.M., Urban solar energy potential in Greece: A statistical calculation model of suitable built roof areas for photovoltaics, Energy and Buildings (2013), 62, 459-468

As those studies showed, the parameters that affect the availability can be classified in three main groups, excluding the climate:

1. Density of the built environment (which affects mutual shading)
2. Competitive uses of the roof
3. Structural and regulatory issues

The resulting estimates of maximum building-PV capacity potential for sloped and flat roofs, are presented in the first three columns of Table 1 below.

However, careful examination of evidence gathered through interaction with local experts and stakeholders on the quality of the Georgian building stock, as done within the "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" (Component 3) report of this study, has highlighted some inherent constructional and typological criticalities, which further reduce the total installation potential on Georgian cities' roofs. In particular, sloped roofs in single family and small residential houses are made of the corrugated steel sheets, supported by wooden beams, resting on non-bearing walls: this leads to limited bearing capacity of the roofs, the lack of adequate structural support for the PVs and the difficulty in ensuring effective water tightness. Therefore, it has been estimated that a constraint factor of 80% has to be applied to the overall total PV capacity of single family houses/sloped roof potential. In other words, the constrained capacity potential cannot exceed 20%[2] of the total capacity estimated.

Hence, the estimates for maximum building-PV capacity potential used for the purposes of the scenario building in Section 2.4 are those presented in the highlighted third and fifth columns of Table 1, i.e. *Flat roof PV capacity* and *"Constrained" sloped roof capacity*.

Table 1: Maximum building-PV capacity potential, for sloped roof and flat roof buildings, MW

City	Sloped roof PV capacity (MWp)	Flat roof PV capacity (MWp)	Total potential PV capacity (MWp)	"Constrained" Sloped roof PV capacity (MWp)	Total "Constrained" Potential PV capacity (MWp)
Tbilisi	477	712	1,189	95	808
Batumi	130	76	205	26	101
Kutaisi	132	146	278	26	173
Rustavi	88	99	187	17	117
Total	822	1,033	1,855	165	1199

[2] A recent (2016) study by the National Renewable Energy Laboratory (NREL) in the US proposes, for the much more favourable US market, a 26% respective figure when considering "small buildings" (https://www.nrel.gov/docs/fy16osti/65298.pdf)

Besides the sheer technical justification, experience with small-scale sustainable energy financing (i.e. not restraining to building-PV) at a world-wide scale shows, that households as borrowers are usually worse-off when seeking financing on an individual basis, compared to commercial clients (SMEs, etc.). For example, when it comes to the residential market a key barrier is the credibility of the borrower; the banks usually respond with high collateral requests and therefore the respective loan terms are usually not attractive and are not preferred by the people. In contrast, commercial clients may have better access to on-balance sheet financing and hence to more attractive loans.

Secondly, the segmentation of the market makes the situation even more difficult. A large number of small-sized projects can only be addressed by (local) banks, with an established and extensive retail network. There, however, the inexperience of the banks in this type of investments and the terms they offer are usually a disincentive for the prospective investors. On the contrary, multilaterals and investment banks which have developed the expertise on small-scale sustainable energy financing, may only approach this large but clustered market through on-lending mechanisms, which in turn have to include the local banks.

Evidence on the above gap is provided by the recent (2017) analysis issued by the Institute of Climate Economics[3]. The INOGATE programme has also discussed the performance of financing mechanism in Ukraine, Moldova and Georgia, through the “Review of and Guide for the Financial Support Facilities for Renewable Energy and Energy Efficiency in Energy Community Partner Countries”[4], as it is discussed further in section 4.3 of the “Review of Eastern Partner Countries experience with building-PVs” report of this study.

2.2 Defining market segments

As discussed in “Review of EU Experience with Solar PV in buildings” report of this study, PV is a modular technology that can be installed in different sizes and for a wide range of applications. Worldwide PV deployment is in fact differentiated by market segments and allocation of installed capacity across them, can vary among countries, historically as a consequence of different policy measures implemented, see “Review of EU Experience with Solar PV in buildings” report. For example, Figure 1 presents PV installed capacity across market segments and EU countries, showing the quite different installation patterns[5]. Some countries, such as Romania, are dominated by large utility-scale PV systems, whilst in others, such as Denmark and Belgium, only smaller size PV systems are installed. Indeed, a generally accepted differentiation of the PV market segments usually encompasses the following: residential, commercial/industrial and utility scale segments. Despite the fact that specific definitions can vary, according to the underlying assumptions made, the main characterising factors of those different segments are generally the system’s size and the final end user and investor of the system itself. For example, Figure 1 shows

[3] Using credit lines to foster green lending: opportunities and challenges - September 2017 – I4CE (https://www.i4ce.org/wp-core/wp-content/uploads/2017/09/0908-I4CE2672-Green-Credit-Lines-Web.pdf)

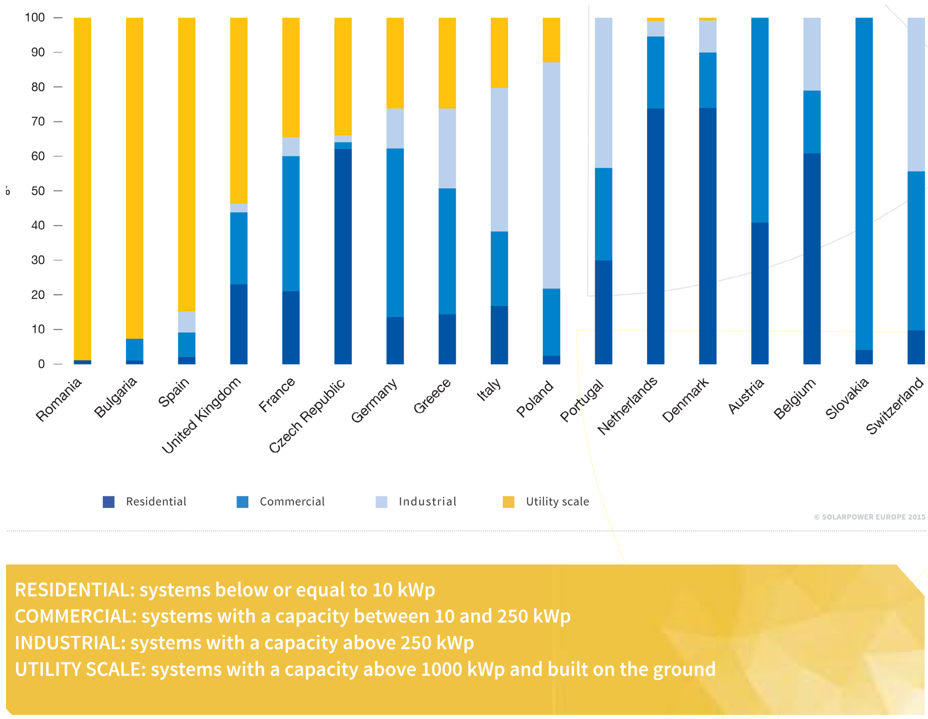
[4]http://www.inogate.org/documents/22042016_INOGATE_Financial_Support_Facilities_Study_Draft_Final_KS.pdf

[5] Solar Power Europe (2016). Global Market Outlook For Solar Power / 2017 - 2021. Solar Power Europe Report. 2016. Available at: http://www.solarpowereurope.org/index.php?eID=tx_nawsecuredl&u=0&g=0&t=1501686591&hash=b2aeefac633c3c059fc0ae5b41cea8e21223e2e4&file=fileadmin/user_upload/documents/GMO/GMO_2017-2021_v2.pdf.

assumptions used by Solar Power Europe to categorize market segments, based on the varying range of systems' size.

Therefore, in order to best define conditions for PV deployment in Georgian cities, a clear definition of market segments has to be provided, particularly as the dynamics and economics of PV market development are affected by several variables, such as the PV systems' sizing and investment cost, the electricity demand profile of the end users etc. Those variables can vary across different PV applications and market segments, yet they are the key input for the end user analysis (please see Section 3 that follows). Together with the associated assumptions made, they are presented in Section 3.1.

Figure 1: European solar PV cumulative capacity segmentation by country and market segments definition, 2014. Source: Solar Power Europe 2016[6]



In the EU, the development of building-PVs, both Building Applied (BAPV) and Building Integrated ones, has been mostly driven by small/medium scale installations owned by individuals/households, SMEs and public bodies (e.g. schools). We therefore assume similar trends for Georgia, thus ruling out of the analysis large ground mounted, utility scale PV systems, which are in any case subject to entirely different legal, normative and regulatory frameworks. We hence focus on the residential and commercial market segments, which are here defined as follows:

- **Residential**: small PV systems owned by individuals/households
- **Non-residential**: small to medium size PV systems, owned by commercial actors/SMEs or the public sector. We define this segment as non-residential, rather than commercial, as it can include PV systems installed on public buildings. Public buildings are likely to be

[6] Solar Power Europe (2016). Global Market Outlook For Solar Power / 2017 - 2021. Solar Power Europe Report. 2016. Available at: http://www.solarpowereurope.org/index.php?eID=tx_nawsecuredl&u=0&g=0&t=1501686591&hash=b2aeefac633c3c059fc0ae5b41cea8e21223e2e4&file=fileadmin/user_upload/documents/GMO/GMO_2017-2021_v2.pdf.

an interesting target for building-PV deployment in Georgia as, particularly during the early stages of the PV market development, public authorities could play a leading and demonstrative role, by installing PV systems on public premises. However, due to lack of specific data on public buildings, it has not been possible to differentiate the segment as such; instead it has been merged together with commercial one, in a single non-residential market segment.

For the purpose of this analysis and the use of the total energy potential estimated in "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study, it is further assumed that small PV systems will be installed by individuals/households on the sloped roofs that characterize the single family houses, whereas larger investments, in medium size PV systems, are undertaken by commercial actors and public bodies on large buildings, characterised by flat roofs. In other words, maximum installation potential for the residential sector is assumed to be equal to the *"Constrained" sloped roof* PV capacity and for the non-residential sector equal to the *Flat roof PV capacity* as estimated in "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study and presented in Table 1 (Section 2.1): i.e. total maximum installation potential of building-PV equal to 165 MW for residential and 1,033 MW for non-residential.

It should be noted, that characterization of the two market segments implies the definition and data gathering for several variables, which can vary significantly, and, as such, affect the analysis and the calculations presented in the following sections. In particular, the most relevant differences between residential and non-residential market segments are in terms of: PV system size, PV total investment costs, retail electricity price paid, investment characteristics as well as the level of policy support, which results from analysis in Section 3.2. Therefore, the key input variables, assumptions and data used for the two market segments in the end-user analysis and cost-benefits analysis will differ; they are summarised in Table 9.

2.3 Policy support to building-PV

2.3.1 Current building-PV market trend and policy framework

The "Review of Eastern Partner Countries experience with building-PVs" report of this study has highlighted that Georgia hasn't currently a comprehensive legislative acts and regulations to promote the use of renewable energy sources (RES) in place, nor RES targets or RES specific policy support tools, such as Feed in Tariffs. Though this situation is expected to change soon, currently Georgia is the only one of the six Eastern Partner countries presenting such a policy gap. It has, however, to be noted, that small hydropower has traditionally been a key sustainable energy development element of the Georgian energy system. Therefore, legacy regulations that can potentially work for all RES have already been incorporated in the Law on Electricity and Natural Gas, as well as in other legislative acts. These in turn allow for RES development through third party access and connection rules, as well as the incorporation of RES in the electricity market. According to the prevailing framework, a potential developer has to select one site/project and submit a proposed tariff to sign a long term PPA. Developers need to submit a financial appraisal of the investment to the Ministry of Energy, in order to get tariffs defined and approved. RES tariff is hence set on a cost-basis evaluation between the plant developer and the Ministry of Energy. Legislation, however, does not imply priority dispatching for RES (as absorption of the

RES generation is defined in each individual PPA), except from the priority allocation of cross-border capacities for newly built (after 2010) power plants. In addition, a net metering scheme has been adopted through amendments on the Law on Electricity and Natural Gas in 2016. The scheme for net metering is open to wind, solar, biomass, and hydropower generation installations with a capacity of up to 100 kW, whereas individual restrictions at connection point level, but also globally in relation to a fraction of the deemed distribution region peak demand, do apply.

RES development is, hence, rather limited in Georgia and, as highlighted in "Review of Eastern Partner Countries experience with building-PVs" report of this study, the PV market is very small. To date PV systems are mainly projects implemented as a result of specific public or private initiatives. Otherwise PV deployment has been very slow, with only very few private small PVs, for which very limited information on their type and sizing is available. Under the current policy framework, PV installations more than 100 kWp can be deployed by private investors by submitting an application directly to the Ministry of Energy and signing a fixed tariff PPA. Since early 2016, PV systems below 100 kWp are instead subject to the net metering regulation. Net metering makes it possible for PV system end-users to get connected to the electricity grid, feed in their surplus and get compensated when the amount supplied exceeds the one taken from the system. PV system owners can connect to the grid free of charge and get paid for their excess electricity a price equal to the weighted average generation cost of electricity as determined by GNERC. RES power plants with capacity below 100 kW do not require licensing by GNERC, nor registration with ESCO (the Georgian Electricity System Commercial Operator) as an electricity market member. In addition, no special permits and licenses have to be obtained for building-PV systems, nor are separate construction permits needed for households.

After the introduction of net metering regulation 8 new micro PV power plants were registered in 2016, with a total installed capacity of 153 kWp. However, there is no clear sign of building-PV to have a significant market uptake, and they still represent a limited and marginal sub-segment of the energy market.

It can therefore be deduced, that despite Georgia's good potential for development of building-PVs, the current legislative framework does not adequately promote this RES technology. The project-by-project tariff approval and the list of RES system to be developed, made available by the Ministry of Energy, is not compatible with a distributed generation approach where private individuals and companies develop their own generation units within a favourable legislative framework. The introduction of net metering for systems of less than 100 kW is a reasonable initial step towards identifying the need for a more suitable policy support for distributed RES system and building-PV within it. However, current electricity retail prices are very low (hardly reaching 0.07€/kWh), making therefore investments in PV systems under the net metering scheme not economically interesting; this will be further highlighted in the results of the end-user analysis, in Section 3.2). It is therefore suggested to tailor specific policy support through a programme, in order to develop the building-PV market. The programme shall serve as a pilot to open up the market, scale up PV deployment and consequently achieve the necessary PV system cost reductions and the development of a national PV sector and value chain.

Such policy efforts would not only lead to a development of the Georgian PV market, but it would also move in the direction of making the Georgian electricity market compatible with EU regulatory requirements. Georgia has just completed its accession to the EU acquis on energy in autumn 2017, by becoming a contracting party to the Energy Community Treaty. This will imply in the years to come a progressive harmonization of the Georgian energy systems and markets to the EU standards, including a level of market reform along the three EU pillars of energy policy, namely security of energy supply, competitiveness and sustainability. Indeed, one of the policy recommendations emerging from the "Review of Eastern Partner Countries experience with building-PVs" report of this study, is to accelerate this harmonization process, in order to guarantee a favourable policy and regulatory framework and to allow the successful development of the building-PV market and its integration in the Georgian energy system. In this line of approach, main conditions for a favourable buildings-PV policy, derived from the experience of the EU-Member States are:

- Presence of a national renewable target and a national commitment/plan to achieve the target. The target should be also projected into a verifiable annual RES development trajectory.
- Presence of a clear and accessible licencing and permit procedure with the objective to achieve a "one-stop-shop" approach for the authorisation, connection and operation of RES plants.
- Presence of a non-discriminatory regulation to develop generation capacity and connect to national distribution and transmission grid.

Table 2: Summary of PV policy outlook in Georgia

Main support for PV	Level of support	Net metering	Estimated value of kWh in net metering	VAT exemption on PV equipment	Other measures
There is no general support mechanism. RES are developed once included in a development list by the Ministry at regulated prices.	Regulated tariffs are defined ad-hoc according to project cost.	Allowed <100kW with remuneration of excess electricity	Highest tariff at some 0.063 €/kWh	Yes	New initiative from Georgian Government is that micro power plants are exempt of VAT, profit and income tax

2.3.2 Designing building-PV policy support

As already highlighted in "Review of Eastern Partner Countries experience with building-PVs" report of this study, any potential policy decision on building-PV support should naturally be based on the experience and evidence drawn from the early stage PV market deployment policy frameworks, implemented since the 2000s in leading European countries, as they were reviewed in the "Review of EU Experience with Solar PV in buildings" (Component 1) report. The introduction of Feed In Tariff (FiT) support scheme[7], in particular, has been crucial for the development of the European PV sector, as it enabled a steady and predictable remuneration over the support period it was granted. FiT implementation has led, since the mid-2000s, the European PV sector to grow to the current GWs scale, in countries such as Germany, Spain, Italy and UK. In a context of quite mature RES markets, the current EU policy framework is progressively reducing FiT scheme support, in favour of more 'market based' policy support tools,

[7] Support schemes in general including the Feed in Tariff scheme are elaborated in the "Review of EU Experience with Solar PV in buildings" (Component 1) report of this study

such as Feed in Premium or quota and auction based mechanisms. Nonetheless, for a country like Georgia, characterized by only nascent electricity market and almost non-existent PV (including building-PV) sector, we consider and analyse the implementation of policy support instrument similar to those already implemented in other European countries at the early stages of their PV sector development, in particular:

- Capital based support;
- Production based support, in the form of: net metering and Feed in Tariff scheme (FiT).

We do not consider Feed in Premium[8] (FiP), as current design of Georgian electricity market does not allow to elicit a clear wholesale price (see Section 5.4), therefore not allowing a proper definition of premium tariffs.

In the next Section 2.4, we develop scenarios for building-PV penetration in Georgian cities, which assume a progressive increase of policy support through the implementation of:

- Net metering scheme, as already in place (see Section 2.3.1)
- Capital grants, defined as a percentage of the initial building-PV investment cost;
- Feed in Tariff scheme (FiT) offering a specified generation tariff for the total PV electricity generated, over a 20 years' timeframe.

The respective levels of support, i.e. the capital grant, as a percentage of the initial investment cost, and the tariff offered under FiT scheme are calculated in Section 3.2 through an investment appraisal analysis, which optimizes policy support in order to achieve returns on the investment sufficient to incentivise end-users to invest in PV systems.

2.4 Scenario building

In order to develop scenarios for building-PV deployment in the selected Georgian cities, we have firstly calculated a progressive deployment of the estimated maximum total capacity potential from 2018 up to 2030 for each market segment, as derived from the "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study and presented in highlighted third and fifth columns in Table 1, i.e. *"Constrained" sloped roof* PV capacity for residential and *Flat roof PV capacity* for the non-residential segment. With a view to account for progressive maturity of the Georgian PV market, we assumed a staged implementation, implying an S-shaped learning curve i.e. initial slower deployment and a faster uptake at later stages; in particular we assumed that:

- 30% of the total potential will be deployed in the first half of the period (2018-2024),
- and the remaining 70% deployed between 2025 and 2030.

This would lead to a total installed building-PV capacity of about 360MW by 2024 and about 840MW by 2030 (Table 3).

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[8] Support schemes in general including the Feed in Premium scheme are elaborated in the "Review of EU Experience with Solar PV in buildings" (Component 1) report of this study

Table 3: Staged deployment of maximum estimated building-PV potential by 2030, MW

	2018-2024	2025-2030
Tbilisi		
Residential	29	67
Non-residential	214	499
Batumi		
Residential	8	18
Non-residential	23	53
Kutaisi		
Residential	8	18
Non-residential	44	102
Rustavi		
Residential	5	12
Non-residential	30	69
Total	***360***	***839***

Note: 30% of total PV capacity 2018-2024; 70% of total PV capacity 2025-2030

However, considering that the focus of this study is to analyse and assess the implementation of pilot PV policy mechanisms to open up and support early stage development of the Georgian building-PV sector, we decided to focus the analysis to a shorter **timeframe: the first 5 years, i.e. 2018-2022**. Such pilot policy programme could then be followed by a new policy framework updated to account for the countries' PV market evolution in the first years. Moreover, considering that the Georgian building-PV market is still nascent and in the context of a quickly evolving energy system and policy framework, we deemed it rather unrealistic to reliably foresee its future developments up to 2030.

Table 4 below shows the total building-PV installation potential for each Georgian city and market segment over the 2018-2022 period (extracted from data presented in Table 3 above). These figures can be interpreted as the highest building-PV installation target within the 2018-2022 timeframe.

Table 4: Total building-PV installation potential, per city and market segment (equal to High Scenario), MW

	2018	2019	2020	2021	2022	Total over 5 years
Tbilisi						
Residential	4	4	4	4	4	20

Non-residential	31	31	31	31	31	153
Batumi						
Residential	1	1	1	1	1	6
Non-residential	3	3	3	3	3	16
Kutaisi						
Residential	1	1	1	1	1	6
Non-residential	6	6	6	6	6	31
Rustavi						
Residential	1	1	1	1	1	4
Non-residential	4	4	4	4	4	21
Total Domestic						*35*
Total commercial						*221*
Total Georgia						***257***

Consequently, we developed three possible scenarios of potential future building-PV penetration, assuming different levels of deployment over the 5 years' period of the total building-PV potential estimated for each city, as presented in Table 5: the high scenario assumes that the total potential is actually achieved (to 100%), the medium scenario assumes a 50% deployment and the low scenario a 5% deployment.

-

Table 6 below presents installed building-PV capacity for Georgia, namely aggregating figures for the four cities, under the three scenarios. Overall, total installed building-PV capacities over the 5 years period considered are:

- 257MW of installed building-PV under High Scenario;
- 128MW of installed building-PV under Medium Scenario;
- 13MW of installed building-PV under Low Scenario.

Table 5: High, Medium and Low Scenarios for PV deployment in Georgia, residential and non-residential market segment, MW (2018-2022)

Total building-PV installation (MW)	2018	2019	2020	2021	2022	Total over 5 years
Residential						

High	7	7	7	7	7	35
Medium	4	4	4	4	4	18
Low	0	0	0	0	0	2
Non-residential						
High	44	44	44	44	44	221
Medium	22	22	22	22	22	111
Low	2	2	2	2	2	11
Total						
High	51	51	51	51	51	***257***
Medium	26	26	26	26	26	***128***
Low	3	3	3	3	3	***13***

Such different levels of deployment are assumed in relation to different levels of policy commitment to building-PV. Indeed, the experience in other European countries has highlighted the role of policy support as crucial for PV deployment (see also discussion in "Review of EU Experience with Solar PV in buildings" report of this study), in particular for its early stage uptake in a still emerging PV markets, such as the Georgian one at the time of writing this report. The stronger the policy support, the more likely PV deployment is. Therefore, we have associated to each deployment scenario the progressive introduction of increasing policy support to building-PV, in particular:

- The Low Scenario assumes a relatively low deployment of the total installation potential (13MW) and is developed taking into account the current Georgian policy framework and support to building-PV, i.e. the net metering scheme for systems <100kWp. However, current levels of retail electricity prices make PV systems investments not profitable enough to incentivise deployment (see also Section 3.2). We have therefore assumed for this scenario the introduction of a capital grant support scheme for building-PV, in order to make the internal rate of return (IRR) of the investment at least equal to the estimated WACC (13% for residential and 10% for non-residential as explained in Section 3).
- The Medium Scenario assumes a higher level of PV deployment (128MW), which is considered to be the result of the introduction of a FiT scheme, for tariff levels which would make the investment profitable enough (resulting in the same IRR levels as the Low scenario) but that would provide a more stable financial framework and increase confidence to the investors.
- The High Scenario assumes that the total building-PV installation potential is actually achieved (256MW), thanks to the introduction of a FiT scheme as in the Medium scenario, but in conjunction to a capital grant which would make the investment even more profitable and therefore more likely to happen (i.e. plus 5% units from initial IRR levels).

Table 6: Summary of Scenarios assumptions

Scenario	Deployment (as % of Total building-PV potential)	Total building-PV installation, MW	Policy support assumptions	Grid management
High	100%	256 MW	FiT (fixed) + capital grant for IRR 18% for residential and 15% for non-residential	Grid reinforcement might be required
Medium	50%	128 MW	FiT – IRR 13% for residential and 10% for non-residential	Business as usual
Low	5%	13 MW	Net metering + capital grant / IRR 13% for residential and 10% for non-residential	Business as usual

In other words, the three scenarios in reality represent different levels of Georgian government commitment over building-PV deployment in the country, to which incremental levels of building-PV penetration may be associated. The higher the commitment, the higher is the policy support implemented, but also the more favourable should be the regulatory framework and grid management conditions: to date has been estimated a limit of about 100MW of wind and PV combined to be connected to Georgian grid by 2021. This value may increase to a maximum of about 400MW by the 2030, as it is mentioned in the Georgian TYNDP[9] 2017-2027. The Low and Medium scenarios imply respectively a total building-PV installed capacity of 13 MW and 128 MW by 2022, which can both be considered to more or less fit within the Variable Renewable Electricity (VRE) absorbability limits, currently identified by the Georgian TSO. The High Scenario, instead, would imply the connection to the grid of over 250MW by 2022, which could probably require an additional concerted effort in terms of grid reinforcement and management.

Table 7 presents cumulative figures for the three scenarios of building-PV penetration in the four Georgian cities over the 5-year period (2018-2022). The upper limit (i.e. the High Scenario) implies a total installed capacity of over 250MW which account for a total of 29,228 installations. The number of installations has been calculated by dividing MW installed by the average installed capacity in each market segment – see Table 9, net metering figures have been used.

[9] http://www.gse.com.ge/sw/static/file/TYNDP_GE-2017-2027_ENG.pdf

Table 7: Cumulative building-PV deployment data over 2018-2022, MW (High, Medium and Low Scenarios)

Scenario	Cumulative PV install over 5 years (MW)	% residential (MW)	% non-residential (MW)	# installations - residential	# installations - non-residential	# installations - Total
High	257	35	221	19,683	6,399	26,083
Medium	128	18	111	9,842	3,200	13,041
Low	13	2	11	984	320	1,304

One has, however, to critically appraise how realistic these figures are. Without a comprehensive legislation and regulation for RES penetration in place, it is not possible to frame such building-PV deployment figures within wider national RES deployment figures. Therefore, we compare estimated figures for Georgia with the installed capacity and the number of installations of selected European countries. Table 8 presents installed capacity for rooftop and small to medium size PV systems in Germany, Italy and Greece (in 2015). Germany and Italy have both experienced high levels of PV deployment over the last decade: the installed PV capacity and the number of installations are way higher than the upper limit we have estimated for Georgia rooftop segment. Greece is a slightly less developed rooftop PV market, and still, our estimated Georgian figures are well below Greece's rooftop PV installed capacity, i.e. 257MW for the High Scenario which compares to about 540MW of rooftop PV installed in Greece.

Table 8: Installed capacity and number of installations in reference European countries

Greece rooftop (MW, 2015)	Germany <10kW (MW, 2015)	Germany 10-100kW (MW, 2015)	Germany <10kW (# installations 2015)	Germany 10-100kW (# installations 2015)	Italy (# rooftop installations 2015)
540	11,116	9,528	428,400	367,200	420,000

In the following sections the three scenarios developed, and the building-PV policy support that they imply, are taken as a basis, in order to develop the end-user analysis of the incentive to invest in building-PV in Georgia. This analysis will determine the minimum levels of policy support needed to make a building-PV investment feasible, and hence also possible, in order to achieve the building-PV penetration rates in Georgian cities, as assumed under the different scenarios developed (Table 5).

3 End-user analysis

The end-user analysis is an investment appraisal of building-PV systems for the two market segments assumed: the residential and the non-residential sector.

A typical financial cash flow analysis of each investment type has been conducted, in order to identify the specific investment's Internal Rate of Return (IRR). The aim is to understand the economics of current building-PV policy framework and to estimate the level of policy support, in terms of FiT or capital grant levels, necessary to achieve adequate investment returns, which may properly incentivise the deployment of building-PV both in the residential and non-residential market segments.

- As a first step, the Net Metering (NM) scheme currently implemented in Georgia has been evaluated, in order to identify whether it provides adequate economic incentives to residential and non-residential investors. The results, presented in more detail in the discussion below, indicated that the current support through the NM scheme is rather insufficient and the investments are not economically feasible in both market segments. Therefore, it has been decided to investigate the implementation of capital grants in parallel to the NM scheme, or the introduction of a FiT for building-PV systems, as means to improve the economic performance of the investments. This analysis is in line with the policy assumptions associated with the building-PV deployment Scenarios developed in Section 2.4 (please also refer to

Table 6).

- The analysis has been conducted for the five-year period assumed, i.e. 2018-2022, so as to provide the necessary inputs in terms of the level of policy support to the cost benefits analysis of the policy measures implemented under the three building-PV deployment Scenarios (

Table 6). Investment appraisal has been done for both residential and the non-residential market segment and for the three deployment and policy scenarios described in Section 2.4.

3.1 Assumptions and data

The financial appraisal model has been developed, to enable the cash-flow analysis for the whole lifetime of building-PV systems (20 years). System performance characteristics have been taken from the analysis conducted in the "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study and, for the sake of simplicity, the average production of building-PV systems in the target four cities (Tbilisi, Batumi, Kutaisi and Rustavi) has been used. Economic variables such as building-PV investment and operation and maintenance (O&M) costs, as well as other financial and macroeconomic assumptions, have been taken from literature review, discussions with local experts and have been discussed with national stakeholders during the final mission to the countries in September 2017. Wholesale and end-user electricity prices reported in the "Review of Eastern Partner Countries experience with building-PVs" report of this study have been used and, wherever possible, better defined thanks to information provided by national experts. The data used for the analysis and the relative sources are summarized in Table 9.

It should be noted, that the results of the analysis are sensitive to the underlying assumptions of the data used. For example, in absence of robust enough projections and references, the end user electricity tariff has been assumed to increase over time according to the annual inflation which is not exactly the case. Hence, since projections over a long period (25yrs) were necessary, the resulting IRR levels are actually a "best guess" of the investment performance. Hence, since projections over a long period (25yrs) were necessary, the resulting IRR levels inevitably include a high degree of uncertainty, given the variance that can occur in critical parameters of the calculation, such as the capital cost and inflation rates, over this prolonged period.

Table 9: Data used for end user and cost benefit analysis

Key Input data		Net metering		Fit PPA		
Description	**Unit**	**Residential**	**Non-Residential**	**Residential**	**Non-Residential**	**Comments**
Technical Characteristics						
Installed capacity	kW	1.8	34.6	3.0	50	For NM capacity was calculated based on annual electricity consumption using a factor of 1.3 to account for non-optimum conditions/sizing. For FiT PPA indicative reasonable figures were used.
Annual Yield (1st Year)	kWh	1,127	1,127	1,127	1,127	Based on “Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries” report average figure for the 4 cities minus 10% reduction for various additional losses (e.g. near shading).
Average annual panel output reduction	% first 10 years	0.50%	0.50%	0.50%	0.50%	
	% 10-20 years	1.00%	1.00%	1.00%	1.00%	
Self-consumption share	%	40%	40%	-	-	Estimate value from http://en.sma-sunny.com/en/basic-information-about-designing-systems-for-self-consumption/
Electricity Consumption Elements						

Electricity consumption	kWh/y	1600	30000	Non-applicable	Non-applicable	For households according to the GNERC. For non-residential indicative.
Average annual electricity consumption increase	%	1.5%	1.5%	1.5%	1.5%	Half of 2005-2012 average increase for households.
End user electricity Tariff	GEL/kWh	0.170	0.145	0.170	0.145	For TELASI company region incl. VAT (cat 2 household consumption & LV connection for commercial)
	EURO/kWh	0.063	0.054	0.063	0.054	
Average annual electricity tariff increase	%	2.9%	2.9%	2.9%	2.9%	Equal to average inflation
Total Electricity Costs	GEL/yr	272	4,363	272	873	
(1st year)	€/yr	101	1,622	101	324	
NM excess energy remuneration (1st year)	€/kWh	0.041	0.041	-	-	Based on an average of 0.110 GEL/kWh (national experts' information)
Annual total electricity consumption (2016)	MWh	11,000,000				Source: IEA (http://www.iea.org/countries/non-membercountries/georgia/)
Cost Elements						
Specific Investment Cost (€/kWp)	€/kWp	1400	1200	1400	1200	For residential from literature. Reduced figure for non-residential to capture economies of scale
Total Investment Cost	€	2,520	41,520	4,200	60,000	

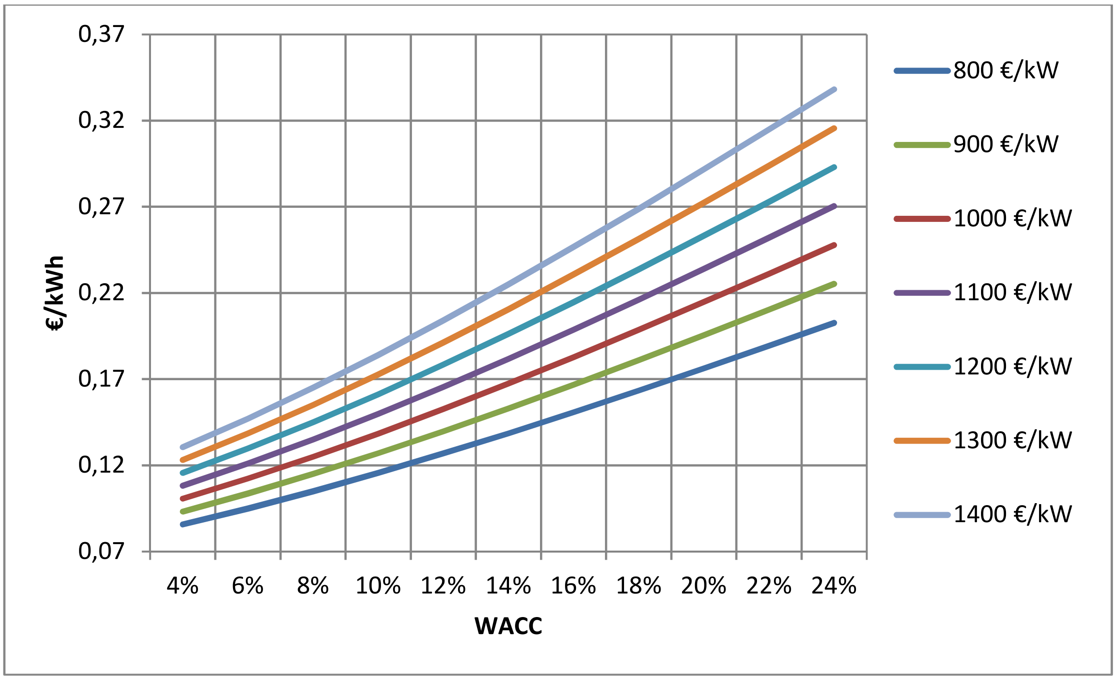
Annual investment cost reduction	%	3%	3%	3%	3%	http://www.nrel.gov/docs/fy15osti/64898.pdf : Analysts project that from 2014-2020, system prices will fall 16%-33% for residential systems and 26%-36% for utility-scale systems, or between 3%-12% per year
Insurance	%	0.005	0.005	0.005	0.005	From HELAPCO (www.helapco.gr) O&M costs for small rooftop systems 1.5% of investment. For non-residential systems max rate of IRENA's report http://www.irena.org/DocumentDownloads/Publications/IRENA_Cost-competitive_power_potential_SEE_2017.pdf
	€/kW/yr	7	6	7	6	
Annual O&M (€/kWp)	€/kWp	21	18	21	15	
	€/yr	38	623	63	750	
Investment Characteristics and Economic Indicators						
Equity share	%	30%	30%	30%	30%	Assumptions
Debt share	%	70%	70%	70%	70%	Assumptions
Loan term	Years	10	10	10	10	Assumptions
Loan interest	%	11.5%	8.0%	11.5%	8.0%	Based on national expert's view (loan in EURO is assumed in all cases)
Depreciation	years	-	7	-	7	For residential no corp. tax is considered hence depreciation is not relevant.
Project Lifetime	years	20	20	20	20	
Equity Expected RoR	%	15.0%	15.0%	15.0%	15.0%	Based on national expert's info on minimum acceptable IRR level for SMEs' investments (10%).
WACC	%	13%	10%	13%	10%	

Tax Rate	%	0.0%	0.0%	0.0%	15.0%	For residential and NM no corp. tax is considered. For non-residential data from: https://investingeorgia.org/en/georgia/taxation
Inflation	%	2.9%	2.9%	2.9%	2.9%	Assumptions based on information from https://tradingeconomics.com/georgia/inflation-cpi/forecast
Benefits						
Electricity emission factor	tonnes CO_2/MWh	0.637				Derived from GNERC presentation on Net Metering, 2016
Price of Carbon (2017)	€/t CO_2	6.68				http://markets.businessinsider.com/commodities/co2-emissionsrechte
		min	***max***	***average***		
Manufacturing and installation (jobs-year/MW)	jobs-year/MW	7.1	43	25.1		IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf
Operation and maintenance (jobs-year/MW)	jobs-year/MW	0.1	0.7	0.4		IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf

3.2 Results and conclusions

As a starting point of the analysis, the Levelised Cost of Energy (LCOE) for various investment cost and WACC levels has been calculated[10], over the 20 years lifetime of the PV system. The results are depicted in Figure 2**Błąd! Nie można odnaleźć źródła odwołania.**. For the current WACC levels of 10-13% (see Table 9), LCOE is between 116-214 €/MWh, which is much higher than current end user electricity tariffs, indicating that under current conditions the technology is not suitable for NM or self-consumption schemes alone. Evidently the cash-flow analysis resulted in negative current IRR levels, both for residential and non-residential NM systems (-9% and -8% respectively).

Figure 2 LCOE for various investment cost and WACC levels



In Table 10 below are presented the results in terms of policy levels necessary, to make building-PV investments profitable enough to incentivise investments in residential and non-residential market segments, i.e.:

- Annual capital grant, as a percentage of the initial building-PV investment cost (%);
- Annual generation tariff offered under the FiT scheme (€/kWh).

Results are presented for the three deployment scenarios estimated and the relative policy measures assumed. Under the Low Scenario, which takes the current Georgian building PV policy support (herein referred to as the NM scheme) as a starting point, a substantial capital grant of approximately 70% of the initial investment cost in the first year is needed, in order to make the investment economically feasible, both in the residential and non-residential market segments. Under the Medium Scenario instead, and for the first year of the FiT programme, a FiT level of

[10] The calculations of the LCOE were based on the simplified formula were only investment and O&M costs are used, not taking into account taxes.

0.205 €/kWh and 0.154 €/kWh has resulted for the residential and non-residential market segments respectively.

Table 10: Results of the end user analysis

Scenarios			YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5
Low	**Net Metering + grant (% of total cost)**	**Residential (13% IRR)**	75.2%	72.8%	70.3%	67.7%	64.8%
		Non-residential (10% IRR)	69.0%	66.3%	63.2%	59.9%	56.4%
Medium	**FiT (€/kWh)**	**Residential (13% IRR)**	0.205	0.199	0.194	0.189	0.184
		Non-residential (10% IRR)	0.154	0.150	0.146	0.142	0.138
High	**FiT + grant (% of total cost)**	**Residential (18% IRR)**	13.40%	13.46%	13.44%	13.43%	13.41%
		Non-residential (15% IRR)	13.48%	13.50%	13.49%	13.47%	13.46%

The High Scenario, which assumes the same FiT levels as the Medium Scenario and the introduction of capital grants in order to make investments even more attractive (i.e. by adding another 5% units to the IRR level), results in a capital grant level of 13,4% for the residential and 13.5% for the non-residential segment.

The capital grant levels presented in Table 10 are granted in the year of installation of the building-PV system, i.e. if a system were to be installed in 2018, it would get a capital grant contribution to initial capital cost of 75.2%, those installed in 2019 a contribution of 72.8% and so on. The FiT are instead guaranteed for building-PV system over their whole lifetime of 20 years and the tariff level would decrease over the 5 years of the programme (i.e. 2018-2022). This would mean that e.g. a residential building-PV system installed in 2018 would get a Feed-in-tariff of 0.205 €/kWh for 20 years, a system installed in 2019 a tariff of 0.199 €/kWh for 20 years, and so on.

For all scenarios, the difference between policy support levels for residential and non-residential segment is due to the lower specific initial investment costs (€/kWp of the system) occurring in the non-residential segment, due to economies of scale and better financial conditions, mainly the lower IRR level expected to be provided by the banking sector. Moreover, the level of support granted each year, both by means of the capital grant and the FiT, decreases over time, as a consequence of assumed reductions in building-PV investment cost over time: the necessary capital grant and FiT levels drop respectively by 13% and 10% in the fifth year (

Figure 3 & Figure 4 below).

Figure 3: Capital grant level reduction over time (Low Scenario)

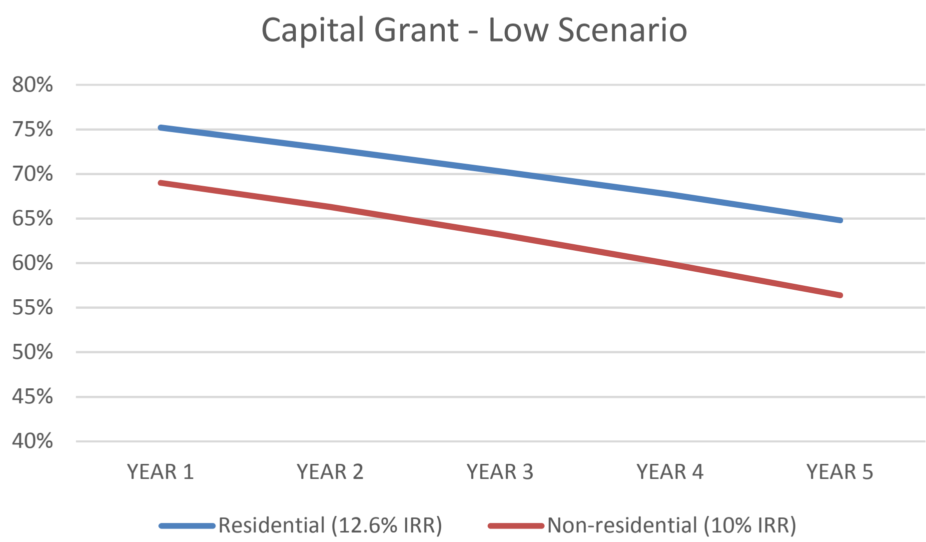
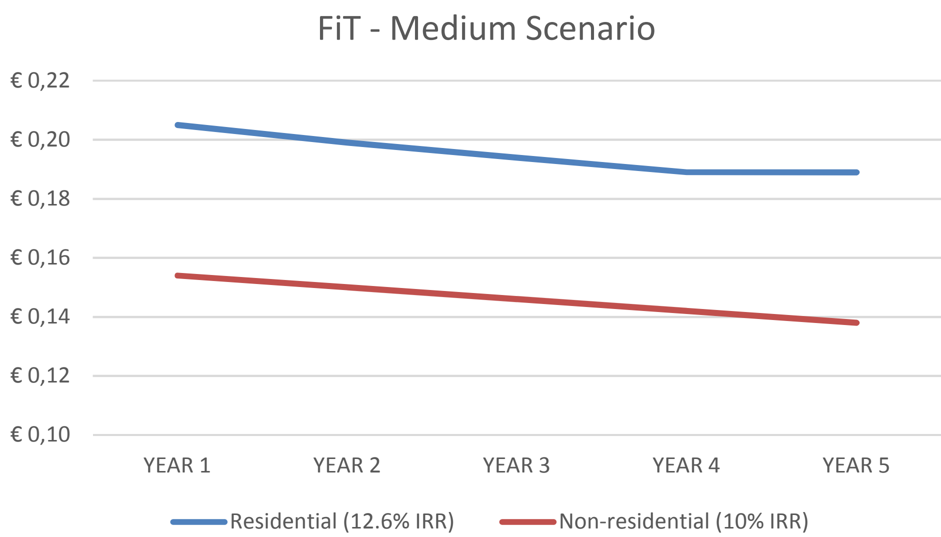


Figure 4: FiT level reduction over time (Medium Scenario)



4 Cost and benefit of policy support

In this section, we present the cost benefit analysis of the policy measures to be implemented, under the three building-PV deployment scenarios described in Section 3.4. The cost benefit analysis provides aggregated results at a system's level, i.e. from the 'social planner' point view. In the following sections we firstly present the main assumptions and data, consequently the results of the cost benefit analysis.

4.1 Assumptions and data

Table 11 recaps assumptions of the three scenarios, which imply different levels of staged building-PV deployment for the two market segments considered (residential and non-residential) over the period 2018-2022 and a relative increasing level of policy commitment.

Table 11: Summary of Scenarios assumptions

Scenario	Deployment (as % of Total building-PV potential)	Residential building-PV installation, MW	Non-residential building-PV installation, MW	TOTAL building-PV installation, MW	Policy support assumptions
High	100%	35 MW (~7 MW/ year)	221 MW (~44MW/year)	256 MW (~ 51 MW/year)	FiT (fixed) + capital grant for IRR 18% for residential and 15% for non-residential
Medium	50%	18 MW (~ 3MW/year)	111 MW (~22MW/year)	128 MW (~ 25 MW/year)	FiT – IRR 13% for residential and 10% for non-residential
Low	5%	2MW (~ 0.4 MW/year)	11 MW (~ 2MW/year)	13 MW (~2.6MW/year)	Net metering + capital grant / IRR 13% for residential and 10% for non-residential

Summing up the policy instruments assumed for the three scenarios are:

- Capital grant programme over the 2018-2022 period (5 years), implemented under the Low Scenario in conjunction with the current net metering scheme and under the High Scenario in conjunction to the FiT scheme in order to achieve higher building PV investment returns (IRR assumed is higher in the High Scenario compared to Low and Medium to guarantee higher building-PV uptake);
- FiT scheme offering a generation tariff for the total electricity generated over 20 years lifetime. It is implemented over the 2018-2022 period (5 years) under the Medium and High Scenarios.

4.1.1 Cost of policy support

The cost of both policy measures is calculated using the figures of FiT and capital grants, estimated by the end-user analysis in Section 3.2 and presented in Table 10 above.

For the capital grant, the estimated annual percentage of the initial investment cost is applied to the investment cost associated to the annual building-PV installation, calculated for each Georgian city and market segment, under Low and High Scenarios deployment levels.

For the FiT scheme, we have initially calculated the annual generation (kWh) according to the deployment levels (in MW) assumed under Medium and High Scenarios for each city and market segment over the 20 years lifetime (see Table 3 for High Scenario figures), by using the first year's annual yield figure and the average annual panel output reduction, as presented in Table 9 (i.e. 1,127 KWh and an output reduction of 0.5% for the first 10 years and 1% for the remaining 10).

The aggregated cost of the FiT scheme, at system's level, accounts both for the overall cost of the incentive, and for the value created for the system due to the electricity generated by the building-PV deployment and fed into the Georgian electricity grid. It is indeed calculated by:

1. multiplying the annual generation over the lifetime of 20 years (kWh) by the FiT level of the relative year of installation, for each city and each market segment (e.g. for residential building-PV systems implemented in 2018 under Medium Scenario we have used FiT of 0.205 €/kWh (see Table 10));
2. and subtracting the value of the annual electricity generated, valued at the relative annual wholesale electricity price of 0.042 €/kWh in 2018, and assuming an annual increase over the lifetime of the PV system of 2.9%.

The economic analysis has been carried out, based on the assumption of a FiT scheme offering to building-PV owners a generation tariff for the total PV electricity generated and fed into the grid. This assumption implies that no self-consumption or net metering mechanism is taken into account for the design of the scheme. In other words, under such a FiT scheme, the building-PV systems would be connected to the main grid with the sole purpose to inject all the electricity generated to the system. The electricity consumed in the building where the PV has been installed, would be measured and billed via a different meter. For the purpose of this study, under this FiT scheme design assumptions, the PV generated electricity fed into the grid has been valued at the national average wholesale price.

It should be noted, however, that in several EU countries, the FiT scheme to support building-PV has been designed in order also to allow self-consumption and in some cases net metering. In this case, the FiT is designed as a tariff given to all kWh generated in the PV system, whereas the electricity is either consumed on site or sold to the market, or included in a net metering mechanism or a combination of the above.

FiT mechanisms accounting for self-consumption may result to be less costly than FiT schemes based on generation tariff (as assumed in this study) as the final cost of the policy may be calculated as the difference between the total cost of the FiT (calculated as at point 1 above) and a value of the electricity generated, which is considerably higher than when valued at wholesale price. Indeed, whereas in the first case we calculate the cost of building-PV FiT support as the total of FiT cost minus the wholesale value of the electricity generated (as we do in this study), allowing self-consumption would imply that we should calculate it assuming a higher value for the electricity component as it would include not only the value of electricity fed into the grid (valued at wholesale price), but also the value of the electricity self-consumed and not fed into the grid (valued at the higher retail electricity prices). This in turn implies that the overall cost of the policy, which has been defined as the difference between the level of remuneration needed to support building PV and the value of electricity, would be lower.

This is to say, that the calculated FiT policy cost in this study (i.e. FIT scheme based on generation tariff) deliberately aims at the highest policy cost, whereas alternative designs of FiT combined with self-consumption scheme may result in a lower policy cost. The latter of course are less likely to be attractive in the still not existing Georgian PV market.

4.1.2 Impact on retail electricity consumers

The potential economic impact of the implementation of the FiT scheme on electricity consumers has been estimated by:

- Calculating the annual cost of the FiT scheme per kWh consumed, namely by dividing the annual Georgian electricity consumption by the total annual FiT scheme cost;
- Calculating the impact on household's annual bill, namely by multiplying the annual cost per kWh consumed by households' annual electricity consumption.

This estimation essentially implies that the overall system cost of the FiT scheme is charged and passed on to the consumer by means of a RES levy. It further implies, that the cost is equally distributed to all consumers (in terms of GEL/kWh consumed) while in reality a regulated burden sharing method is almost always used, in order to allocate the costs to various consumer categories based on specific targets (e.g. protect industrial consumers, minimise welfare losses etc.). Due to data availability constraints, in particular in terms of annual electricity consumption for non-residential consumers, we have only estimated the economic impact on households' bills. Data used are presented in Table 9.

4.1.3 Environmental and social benefits

Analysis of environmental and social benefits has been focused on the quantification of benefits in terms of:

- Value of CO_2 emissions reductions achieved by the implementation of building-PV capacity;
- Number of jobs created.

Contribution of building-PV deployed to CO_2 emission reductions has been calculated by applying the Georgian electricity emission factor (tonnes CO_2/MWh) to the total electricity produced over the lifetime by the building-PV capacity deployed, under the three scenarios and over the programme's period considered (i.e. 2018-2022). A more elaborated method, which would use a dynamic emission factor that would take into account the developments in the Georgian power generation sector (e.g. new investments in thermal and/or RES power stations) is certainly interesting, but it is out of this project's scope. The economic value of such CO_2 emissions reduction has been estimated multiplying them by the EU ETS price of carbon. The 2017 level of the EU price of carbon has been used as a base level and for the investment's period, despite the fact that fluctuations may well occur in the future, as it was beyond the project's goal to carry out an in-depth analysis of this parameter. Still, the calculations can be easily updated in a future follow-up to the project. Data used and their respective references are presented in Table 9.

Deployment of PV has the potential to generate income and create jobs, depending on the extent to which industry, along the different segments of the PV value chain, can employ people locally, leverage existing economic activities or create new ones. The analysis should in theory focus and be disentangled on the basis of information and data on the core segments of the PV value chain: project planning, procurement, manufacturing, transport, installation and grid connection, operation and maintenance (O&M) and decommissioning[11]. However, the lack of available data on the Georgian PV supply chain, mainly due to the fact that the sector is still in its infancy, has severely hindered such a detailed approach of analysis. Therefore, we could only provide an indicative estimate of the impact expected in terms of direct job creation, by applying international estimates of jobs created per MW installed and combining it with the installed building-PV capacity under the three implementation scenarios. In particular, we have used the "employment factor" approach, which indicates the number of full-time equivalent (FTE) jobs created per physical unit of choice, in our case the installed PV peak capacity, but could also be the produced energy. It is used for different phases of the life cycle, those were, for the purpose of this analysis, divided in: manufacturing and installation, operation and maintenance. Employment factors for PV technologies vary in literature, mainly due to variations of labour productivity across countries. For example, employment factor for PV construction in OECD countries is lower than in India (i.e. respectively 11 and 39.6 jobs-year/MW[12]).

To account for this effect, we decided to use for Georgia an average figure between minimum and maximum PV employment figures provided by IRENA[13]. Such figures have been multiplied by the annual building-PV installed capacity for each market segment and under the three scenarios assumed. A summary of data and their respective references are provided on Table 9.

4.2 Results

4.2.1 Policy implementation cost

Table 12 below presents summary of results of the analysis of cost of policy under the three scenarios assumed.

Under the Low Scenario, we have assumed the implementation of a capital grant programme for the period 2018-2022, in conjunction with the currently implemented net metering scheme; the latter would by itself not make building-PV investments profitable enough to incentivize deployment in residential and non-residential sectors. We estimate that under Low Scenario about 2.5 MW of building-PV would be installed, with a resulting average annual cost of the capital grant of some €2 million (for each of the 5 years). The total cost of the capital grant support over

[11] IRENA (2014), "The Socio-economic Benefits of Solar and Wind Energy". Available at: http://www.irena.org/DocumentDownloads/Publications/Socioeconomic_benefits_solar_wind.pdf
[12] IRENA (2014), as above
[13] IRENA (2014), as above

the period 2018-2022 considered, would hence be approximately €9.5 million. This cost would be spread over the 5 years of the programme, as the capital grant payment is given to building-PV system investments in the year of installation and the programme is assumed to last for the 5 years period 2018-2022. For example in 2018 the annual cost would be given by applying the capital grant level estimated of 75.2% (see Table 10) to the total investment cost needed to install 2.8MW (the total building-PV installation assumed in 2018 under the Low Scenario – see Table. 5). This would apply to each year from 2018 to 2022, with a decreasing annual total cost due to decreasing estimated level of the capital grant (see also discussion in Section 4.2 and Figure 5 below).

Under Medium Scenario, we have instead assumed the implementation of a FiT scheme which implicitly better fosters the building-PV market uptake, both for the residential and non-residential sector. The rationale of such an assumption lies both in the evidence of FiT effectiveness from other European countries, which successfully developed domestic PV markets as presented in Component 1 report and discussed in Section 2.3.2, as well as in the implicit characteristics of FiT schemes, which provide investors with a safe investment, offering a predictable and stable policy framework over the lifetime of the projects. Indeed, under Medium Scenario we estimate total annual building-PV installations of about 25MW a year, in both market segments, for an average annual FiT scheme cost of approximately €10 million. The total cost of the scheme over the lifetime of the programme (i.e. 24 years) would hence be about €256 million. It is important to highlight that such cost would be spread over the 24 years lifetime of the FIT programme, with annual cost increasing over the first 5 years, as new building-PV systems are installed each year, incentivised by the FiT scheme. After the first 5 years the annual cost progressively decreases, as no new building-PV systems are assumed to be incentivised after 2022 (the end of the programme) and the annual cost is only because of the annual FiT payments which are due to building-PV systems installed between 2018 and 2022 over their lifetime, i.e. 20 years (see also Section 4.2 and Figure 7).

Under High Scenario, we have assumed higher levels of building-PV deployment, i.e. about 51 MW per year, for a total of 256 MW over the 5 years period considered, and the conjunct implementation of capital grant programme and FiT scheme. Literature and evidence from other European countries has shown, that the success of FITs in deploying PV technologies, has also been due to other policies enacted in parallel, in particular capital grants/soft loan schemes. Capital grants can in particular help in overcoming the barrier of access to capital, which is of high relevance for Georgia. As presented and discussed in the "Review of Eastern Partner Countries experience with building-PVs" report of this study, a recent analysis of the financial conditions in EaP countries carried out by INOGATE[14] highlights adverse local economic conditions, low income levels and limited access to capital both for households and commercial actors (see also discussion in Section 5.3 below). Therefore, and in this context, the implementation of a capital grant scheme in conjunction with FiT would facilitate access to capital, for residential and non-residential investors in building-PV deployment, and hence increase the likelihood of their deployment. Moreover, as discussed in Section 2.4, the level of support estimated in the end-user analysis in Section 3, implicitly assumes a higher IRR, compared to other scenarios, in order to further incentivise building-PV deployment across market segments. The estimated policy costs under the High Scenario are:

[14] http://www.inogate.org/documents/22042016_INOGATE_Financial_Support_Facilities_Study_Draft_Final_KS.pdf

- An average annual FiT cost of about €20 million, for a total of about €511 million over the lifetime of the programme, plus
- An annual capital grant cost (for 5 years) of about €8 million, for a total of about €40 million over the programme period (2018-2022).
- Those figures imply an average annual cost of policy of about €28 million, for a total of about €551 million, over the lifetime of both policy programmes. As in the case of the Medium Scenario above, this cost would be spread over the 25 years' lifetime of the FIT programme, with the annual cost increasing over the first 5 years as new building-PV systems are installed each year, incentivised by the FiT scheme, and then progressively reducing over the lifetime of the programme (see Figure 8).

Table 12: Summary cost benefit analysis results

Summary of Results – Georgia			
PV capacity potential, MW (Component 3)		1198.64	
	Low Scenario	**Medium Scenario**	**High Scenario**
Estimated total installed capacity over 2018-2022 (MW)	**13**	**128**	**257**
Estimated total annual capacity	**2.6**	**25**	**51**
Total electricity produced over lifetime (kWh)	272,342,612	2,726,478,512	5,449,762,819
Policy implemented	**Net-metering + Capital Grant**	**FiT**	**Fit + Capital Grant**
Total Capital Grant cost, over 2018-2022 (€/MW)	***€ 9,543,840***		***€ 40,005,418***
Average annual Capital Grant cost (€/year)	***€ 1,908,768***		***€ 8,001,084***
Capital Grant cost per kWh produced (€/kWh)	***€ 0.04***		***€ 0.01***
Total FiT Cost, over lifetime (€/kWh)		***€ 256,058,066***	***€ 511,841,482***
Average annual FiT cost (€/year)		***€ 10,242,323***	***€ 20,473,659***
Cost of FiT per kWh produced		***€ 0.09***	***€ 0.09***
Total Policy Support Cost over lifetime (€/MW)			***€ 551,846,900***
Average annual cost of total policy support (€/year)			***€ 28,474,743***
Total policy cost per kWh produced (€/kWh)			***€ 0.10***
Benefits			
CO2 emissions saved (tCO2)	**173,575**	**1,737,691**	**3,473,347**

Value of CO2 emission saved (€/tCO2)	**€ 1,159,478**	**€ 11,607,777**	**€ 23,201,956**
Jobs creation (jobs/over lifetime)	**424**	**4,244**	**8,489**
Impact of FIT on consumers			
		Annual Average over lifetime	**Annual Average over lifetime**
Annual total electricity consumption - Georgia, kWh		13,520,360,774	13,520,360,774
Total annual FiT cost		€ 10,669,086	€ 21,326,728
Cost per kWh consumed		€ 0.0008	€ 0.0016
Average retail electr price (resid+non-resid) over the period €/kWh		€ 0.0852	€ 0.0852
Impact on average retail price		€ 0.0102	€ 0.0204
Household consumption kWh/year		1,600	1,600
Impact on family bill €/year		**€ 1.29**	**€ 2.58**

In Figure 5 to Figure 8 are depicted trends for annual costs of both capital grant and FiT programmes, across market segments and under the different scenarios. In both cases the non-residential sector accounts for most of the policy support cost. This is due to the higher assumed installed capacity for the non-residential sector under each scenario, as shown in

Figure 9 (see also Sections 2.1 and 2.4). The annual capital grant cost decreases over time, due to a progressive decrease of the support level, thanks to the respective reduction of building-PV investment (see also Section 3.2). The cost for annual FiT scheme constantly increases over the initial 5 years of the programme (i.e. 2018-2022), as newly installed building-PV systems get into the system and thus also claim FiT support. After 2022, the annual costs are progressively reduced, as: (1) no additional PV systems, and hence no resulting FiT payments, get into the system; and (2) the effect of the increase of wholesale price (over the lifetime of the programme, i.e. 2018-2041) starts having an impact on the overall aggregate FiT cost.

Figure 5: Annual cost of capital grant – residential, non-residential, total (Low Scenario)

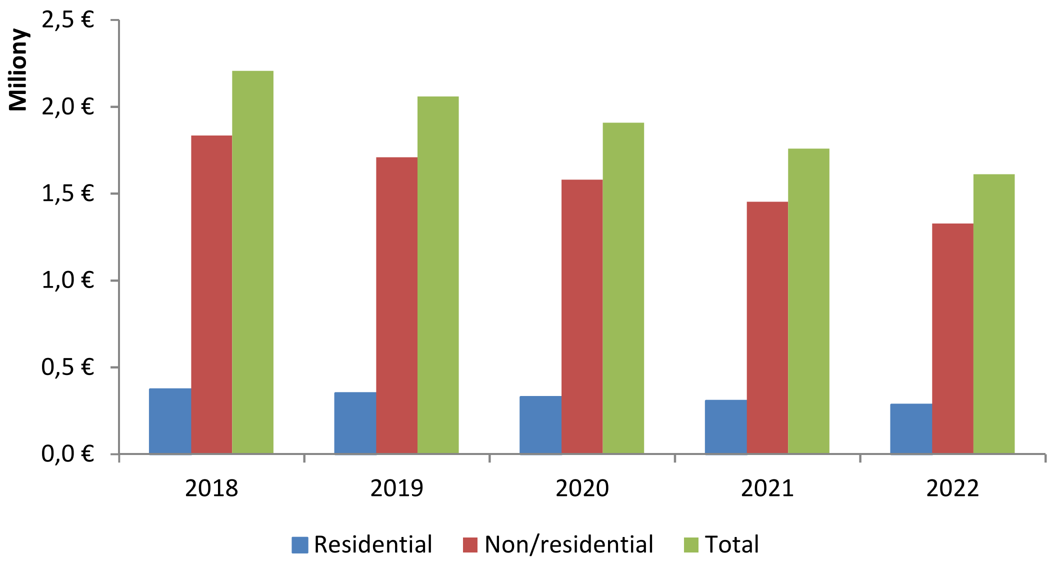


Figure 6: Annual cost of capital grant – residential, non-residential, total (High Scenario)

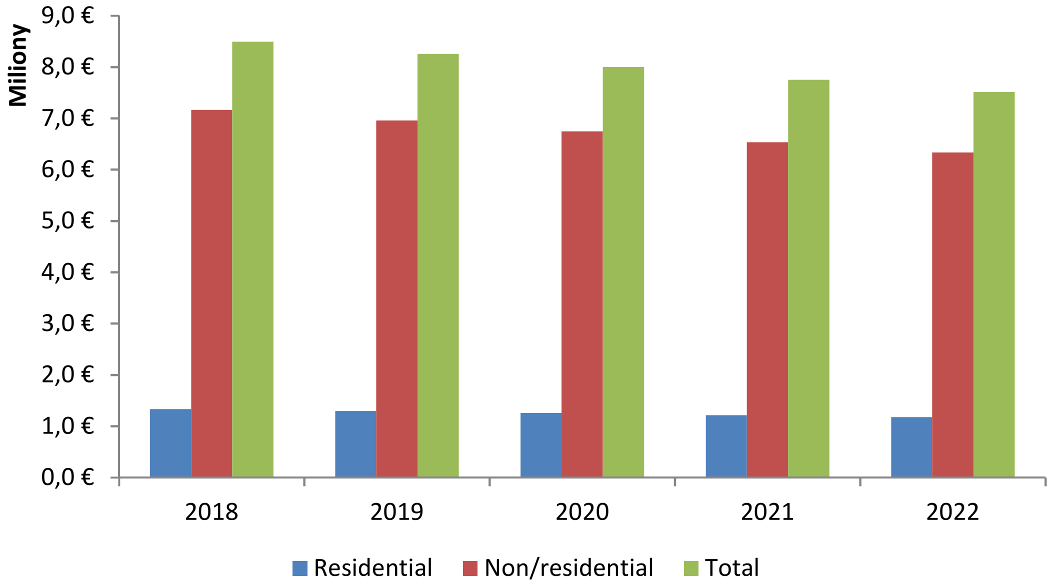


Figure 7: Annual FiT cost - residential, non-residential, total (Medium Scenario)

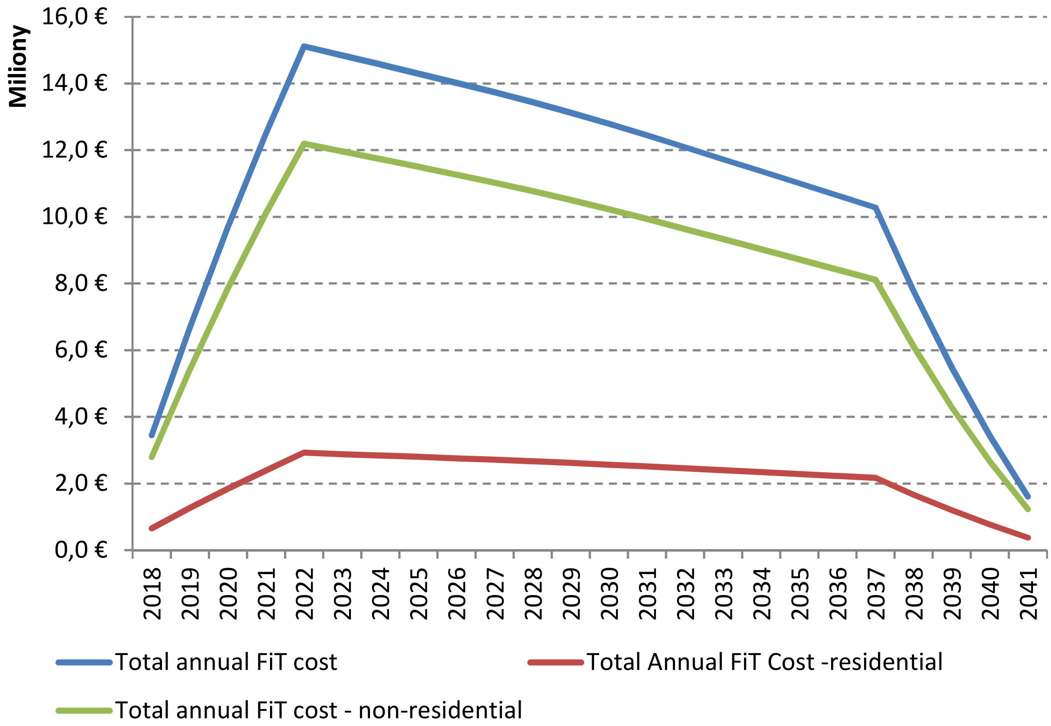


Figure 8: Annual FiT cost - residential, non-residential, total (High Scenario)

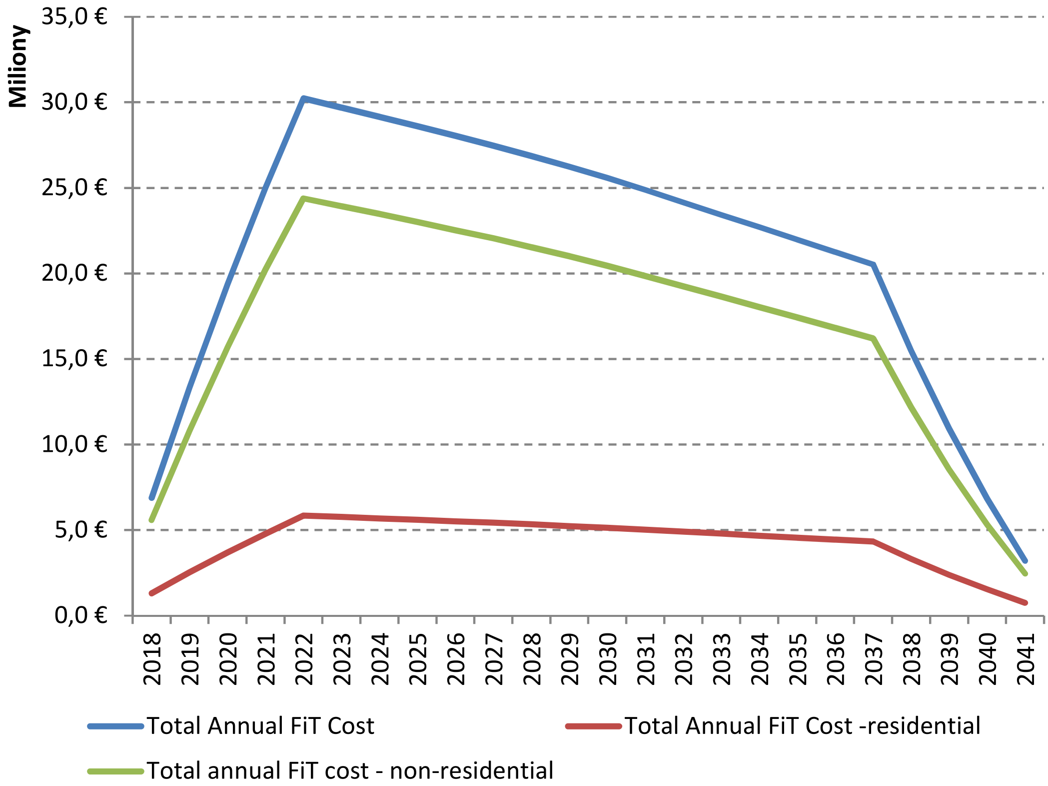
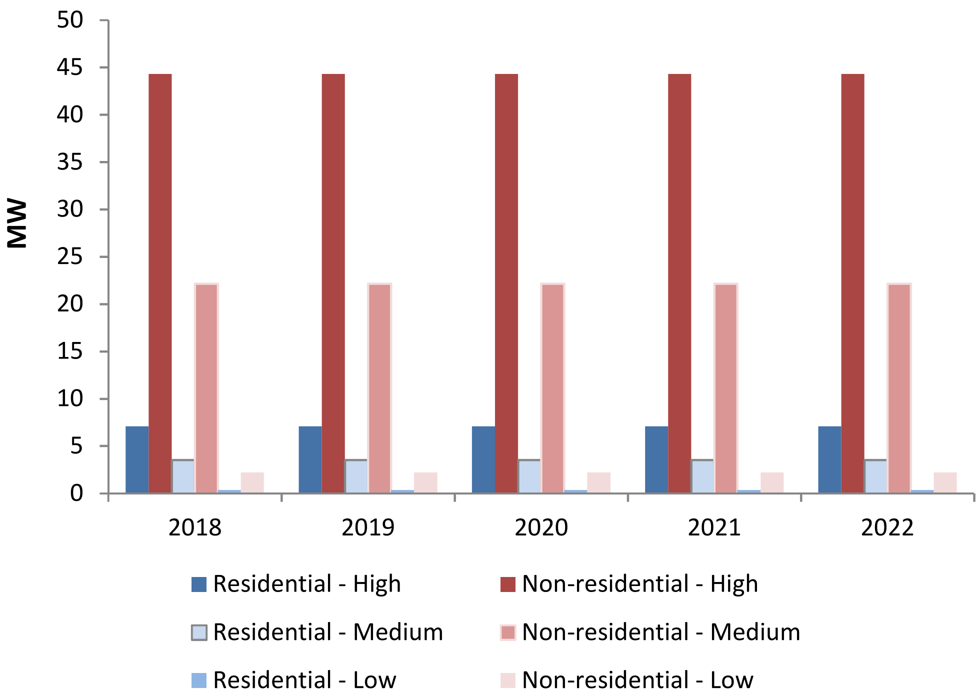


Figure 9: Installed building-PVs: residential, non-residential (High, Medium, Low Scenario)



4.2.2 Impact on retail electricity consumer

The average estimated potential economic impact on households' electricity consumers, as a result of the implementation of FiT scheme under the Medium and High Scenario, is presented in Table 10 . Average

annual cost of the FiT, per kWh consumed, accrues to €0.8 per MWh and €1.6 per MWh under the Medium and High Scenarios, respectively. On average, households' electricity bills would increase by €1.29 and by €2.58 per year, under the Medium and High Scenarios respectively. The evolution of annual cost per kWh consumed and the impact on households' bill is presented in Figure 10 &

Figure 11; not surprisingly they both show similar shape and pattern to annual FiT cost, as presented in Figure 7 and Figure 8, above.

Although a limited impact on final users' electricity bill appears to emerge, it is worthy to point out, that opening up incentive schemes to domestic end users might introduce negative redistributive effect among electricity consumers. Eventually, it may be assumed that only wealthy end users will be able to finance a building-PV system, whereas all electricity final consumers will be asked to pay for the incentive scheme. This adverse effect may be compensated by the introduction of social tariffs, by excluding PV incentive scheme component from the final electricity bill of lower income consumers, or by an exemption of PV cost component in final electricity tariffs for lowest consumption level of block tariff. Specific consumers' categories (such as the public sector, or specific groups of individuals, etc.) may also be excluded. Apparently the larger the degree of allowing exemptions the higher the impact for those paying to cover the incentive mechanism costs.

Figure 10: Annual cost per kWh consumed (€/year)

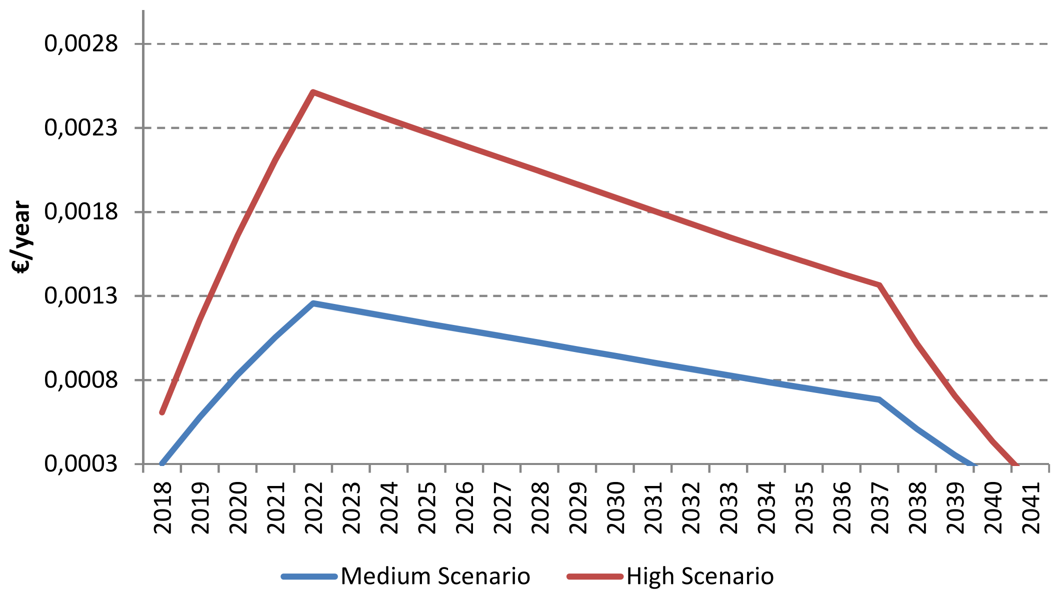
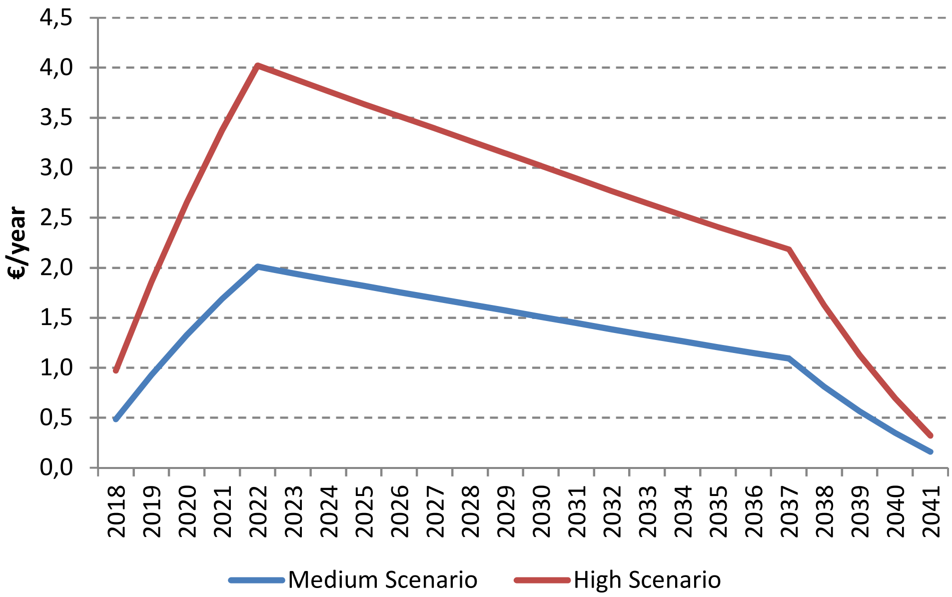


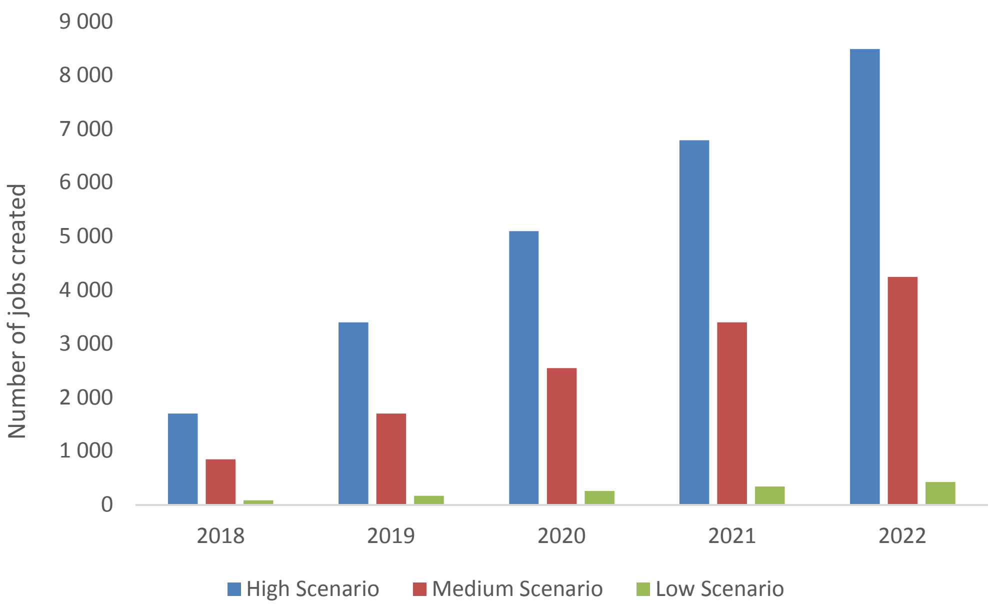
Figure 11: Annual impact on households' bill (€/year)



4.2.3 Environmental and social benefits

Results in terms of CO_2 emissions' reductions achieved and number of jobs created by the deployment of the building-PV capacity (MW), assumed under the three scenarios considered, are presented in Table 10. CO_2 emissions saved range from 173,575 t/CO_2 under Low Scenario to over 3.4 million t/CO_2 under High Scenario. This is equivalent to potential revenues, if traded at current EU ETS price of carbon, of over €1.1 million under Low Scenario to over €23 million under High Scenario. This estimate lies rather on the conservative side, as the calculation does not take into account the increase in the EU ETS price of carbon, expected to take place over the next years, given the ambitious goals of the EU energy and environmental policy. Total direct jobs created over the lifetime of the programme range from 424 jobs under Low Scenario to over 8,000 jobs created under High Scenario. Annual jobs created under different scenarios **are presented in Figure 12.**

Figure 12: Jobs creation, cumulative over 5 years (jobs/year)



4.3 Financing proposed policy support

Discussion in the "Review of Eastern Partner Countries experience with building-PVs" report of this study on financing opportunities for building-PV sector presents a country characterized by "***adverse economic circumstances, low income levels and profitability of the economic units, weak local currency, limited risk taking ability of the local commercial financiers and lack of local currency grants and affordable long term loans***"[15]. Moreover, access to finance for solar PV in buildings is currently limited in Georgia. In other words, it pictures a country with fairly limited internal financial resources and with final end-users and potential investors in building-PV sector characterized by limited access to capital, both for households and commercial actors. It is therefore envisaged, that in absence of a strong enough policy, the support for building-PV uptake will remain rather limited.

The introduction of both capital grant and FiT scheme, as presented and discussed in the previous sections, would help in providing the right incentives for end users to invest in building-PV installations, both in the residential and non-residential market segments.

However, the question is which options are available to finance such policy support programmes.

The possibility of financing the FiT scheme, by passing on the scheme's cost to the final consumers has been presented and discussed in Section 4.2.2 above. Results presented show a fairly limited impact of the scheme on the households' energy bills, when implementing the scenarios considered. However, it is important to stress that due care needs to be given in setting up the FiT programme, in order to avoid excessive burdens on final end-users. In that sense, excessive costs, passed on to electricity bills, would not only further hinder the households' and commercial actors' financial ability to further invest in the building-PV sector, but also potentially increase inequity into the energy system. More people might suffer energy poverty and the adverse redistribution impact of the policy, i.e. richer households with access to capital and higher propensity to invest in building-PV benefiting more than poorer households. Furthermore, such possible adverse consequences might discredit the building-PV policy support programme itself, and eventually also the market liberalisation, as it would be held responsible for rising energy costs. To avoid excessive burden on end-users and adverse social redistribution effects (see also discussion in Section 5.2.2) it is suggested that following actions are taken:

- Set clear annual installed capacity caps (tranches) and monitor the FiT driven building-PV deployment over the 5 years to make sure not to exceed the target annual capacity assumed under the programme design to avoid unjustified increase in overall policy cost.
- Include in the design of the programme measures in support of community energy initiatives, with particular reference to social housing: they are emerging approaches for implementation of RES, which maximise 'localization' of economic benefits accruing from the investment and are suited for projects in locations where the type, scale and nature of the investment are not suited to the traditional financing and private ownership models (e.g. social housing). Moreover, they ensure a more equal and fair redistribution of benefits/revenues accruing from deployment of low carbon technologies, helping in the reduction of preventing fuel poverty and reducing the redistribution impacts of national policies, such as the feed-in tariff scheme. Specific measures could be e.g. higher levels

[15]INOGATE report available at:
http://www.inogate.org/documents/22042016_INOGATE_Financial_Support_Facilities_Study_Draft_Final_KS.pdf

of FiT granted to community energy initiatives, preferential access to administrative procedures, preferential access to soft loan or capital grant schemes.
- Deployment programmes led by local authorities targeted to “socially sensitive” public buildings such as schools or social housing which could also have a high awareness impact to local society.
- Account for self-consumption or net-metering in the design of the FIT scheme in order to reduce overall costs (see discussion in Section 5.1.1).

In considering alternative financing options for policy support to building-PV in Georgia, one should keep in mind what was stated in the “Review of Eastern Partner Countries experience with building-PVs” report of this study : the current Georgian financial system is characterized by the availability of a variety of financial instruments and sources for grants to commercial investment financing, but International Financing Institutions are key contributors to the financial service provision in the country. Moreover, it has also been stated that the potential role of foreign direct investment is critical, in contributing both to technology and financing transfer to the country, through joint ventures and partnerships with commercial actors outside Georgia.

Therefore, it is possible to envisage that the aforementioned proposals for policy support would be partially supported through external capital, both through building-PV specific programmes, financed by International Financing Institutions, and through commercial partnerships with foreign private investors. In particular we would see the capital grant proposals presented in the Low and High Scenarios as particularly suited for financing by International Donors, due to both their relatively small total cost and the fact that their cost burden is limited in time, i.e. to the 5 years of the programme (see Table 12 and discussion in Section 5.2.1).

A well-designed FiT scheme, which will provide high enough returns on the investment (as discussed in Section 3) and a predictable and stable returns and policy framework over the lifetime of the projects, will also potentially help in both mobilizing ‘local’ capital and in triggering the opening of building-PV specific credit lines from ‘local’ credit institutions, as this has been experienced in other European countries.

5 Grid impact

PV technology comprises a promising distributed generation technology, which is suitable to be located in cities and urban areas in large, since it is clean, quiet and nearly maintenance free. As distributed generation, it has the potential of benefiting the system by reducing transmission and distribution losses. Its integration, however, at increased volumes in the distribution network may bring changes in the planning and operational status quo of the overall power system. Quantification of electricity market & grid issues has not been possible and has not been included in the above analysis, neither as costs nor as benefits, due to the inexistent data on behalf of the network operators. However, a qualitative discussion of possible impacts is presented, in accordance to section 2.4 of the “Review of EU Experience with Solar PV in buildings” report. Based on this review of EU experience, and for the purpose of assessing the impact of introducing PV in Georgian buildings, we have addressed the problem and present in what follows a qualitative evaluation of a the main grid issues and implications associated with building-PV deployment in Georgia.

5.1 Hosting capacity

The first issue that needs to be addressed is hosting capacity. Hosting capacity is determined, in order of severity, by: (a) voltage rise on the feeders on which PVs are connected, (b) cable loading and (c) transformer capacity. All those three criteria need to be addressed at a distribution level and in our case at each specific city's level. In Georgia, however, a consolidation of the role of the DSO in the manner provided by the Third Energy Package is not yet in place. The distribution companies carry out both the distribution and supply activities in a bundled manner. There is, therefore, neither an obligation nor an incentive placed on the distribution companies to plan their networks for maximum penetration of RES-based distributed generation. Pursuant to the above, we haven't been able to identify any study carried out by, or on behalf of, the distribution companies addressing this issue. On the legal and institutional side of RES integration DANIDA[16], through the "Support to Energy Efficiency and Sustainable Energy in Georgia" project, aims to support the development of Georgian legislation and regulation to enable electricity from renewable energy sources to be fed into the national power grid. It is, however, not expected that this technical assistance extends to a specific assessment of the hosting capacity of each distribution region in Georgia.

Since the issue is not found to be adequately addressed at distribution level, hosting capacity assessments at an aggregated level (transmission) where sought to be evaluated. GSE, the Georgian TSO, is underway on a tendering process for the development of a RES integration study the Terms of Reference of which could not be available to as during the preparation of this part of our study. However, the Georgian TYNDP[17] 2017-2027 does address RES integration, albeit briefly and collectively for wind and solar power. More specifically, the TYNDP places limits on the wind and solar power integration margins, by quoting that a "Total capacity of **100 MW** is acceptable for Georgian power system **till 2021**, in **2025-2030** (with the consideration of commissioning of all planned regulating HPPs and cross-border lines) this value equals to **400 MW** but not more than 45 MW for each geographic region (9 regions in total[18])".

5.2 Residual load curve

Detailed data reflecting a full year of load data series (i.e. 8760 measurements) have not been available to us and therefore an assessment of the system residual load curve, similar to that of the Moldovan power system included in the "Programme Development for building-PVs based on a Cost-Benefit Analysis: Armenia, Azerbaijan, Belarus, Moldova, Ukraine" report, was not possible. However, The Georgian TYNDP 2017-2027 uses (for planning purposes) four characteristic snapshots of supply/demand balance, which represent system extremes or "stress-hours" and they include winter min and max as well as summer min and max loading conditions as described below on Table 13:

[16] http://um.dk/en/danida-en/activities/countries-regions/eu-neighbours/copy%20of%20countr%201

[17] http://www.gse.com.ge/sw/static/file/TYNDP_GE-2017-2027_ENG.pdf

[18] We haven't been able to locate an explicit definition of the regions in the TYNDP in respect of RES development. It is assumed that Rustavi and Tbilisi belong to one geographic region due to their proximity whereas Kutaisi and Batumi belong to separate regions.

Table 13: Typical “stress-hours” of the Georgian power system (source: GSE)

Date	Hour	Type	Consumption MW
16/12/2016	19:00	Winter Max	2055
16/02/2016	06:00	Winter Min	919
18/07/2016	22:00	Summer Max	1612
06/08/2016	06:00	Summer Min	942

Without going into further analysis, it can easily be observed that there is no real possibility for the PV production to have an impact on the specific load values, since these specific “stress-hours” are not within the daylight hours. An approach, however, of the residual load curve on an hourly basis, would have revealed both the positive impact (i.e. coincidence of PV out with high loading hours of the system) and possibly any negative impact (i.e. coincidence of PV out with low loading hours of the system, where available generation cannot be absorbed). Our discussions with GSE revealed a positive anticipation of PV development in the country, as it would be beneficial in terms of reducing the generation deficit that exists in Western Georgia. In addition, PV development would have a good correlation with the rising electricity consumption due to the respective air conditioning demand during the summer months. Moreover, building-PVs are appreciated even more in this respect, since they are located within the major urban load centres, thereby reducing the need for electricity transfers through the transmission network.

5.3 Centralised vs. de-centralised PV

Based on all pieces of information collected within the project, the decentralised PV development is so far negligible in the country, compared to the current operational electricity generation capacity. Our review on the Georgian TYNDP 2017-2027 reveals that currently there is no formal policy guidance or rule, distinguishing PV capacity additions into utility scale and distributed generation. The TSO, operating in a reasonable but conservative manner, expects exclusively utility-scale new PV capacity additions, within the penetration margins discussed above in section 5.1. This estimate is based, to a great extent, on the very limited level of interest expressed so far by the potential investors in solar PV technology in the country.

5.4 Generation displacement

Given the wholesale market structure in Georgia, which comprises a partially regulated and a partially deregulated market, it is rather difficult to come up with a judgement on which part of the current generation mix would be displaced, if building-PVs are to be developed in the country. There are various reasons for this:

- In Georgia small-scale run of river hydro power plants are either fully or partially deregulated, in contrast to the EU practices, where plants of this kind and below a capacity threshold of 10-15 MW, are considered as renewable systems and thereby enjoy dispatch priority and mandatory offtake of their total output;

- Regulated hydro-electricity prices are defined on the cost-plus principle and therefore the resulting generation prices do not reflect the value or water[19] for each hour of the year;
- Though the organisation of the electricity sector in Georgia does not involve a high ownership concentration, and thereby significant market power of a single incumbent which would influence the wholesale market price, the current market organisation does not involve a spot market. Therefore, there is currently no credible and transparent reference electricity price in Georgia (note: in many EU countries this would be the Day Ahead market price) based on which one could compare the cost of building-PVs. Comparing the building-PV LCOE with the electricity market spot price would have given an indication on whether more market-friendly price support mechanisms like Feed-in Premiums or Contracts for Difference would have applicability in the country.

A year-round dispatch simulation would be required to provide answers on which generation and imports would be displaced, if significant capacity of building-PV would enter the Georgian system. For the time being, an analysis based on 4 specific hours can be considered as indicative, since it is neither representative for the whole year nor relevant, as it falls out of the daylight hours of particular days. However, a snapshot of the generation dispatch on that day provides us with an indication, on how building PVs may compare to the existing sources providing electricity to cover the needs of Georgia.

The winter max loading conditions is a good way to start looking at the Georgian merit order, as this is when the system is put on its ultimate test during the year: frozen rivers diminish the hydropower production, leaving mostly the hydro plants with an ability to regulate their amount of water left in their reservoirs, while all imported energy sources (i.e. both electricity and primary fuels) reach their average annual high prices. In 2016 the peak electricity demand was covered by utilizing the production of all generation sources located in Georgia, with the additional help of imports, namely primarily 248 MW from Azerbaijan, but also 26 MW from Russia. Regardless of the system's stress, at the same time there was also an export to Turkey of 307 MW in that hour. Ranking all resources based on their price, we arrive at a marginal price of GEL 189.6, set by Tkibuli Thermal Power Plant which appears to be the marginal plant.

[19] Some models estimate the water value as the opportunity cost of consuming an alternative fuel to cover the demand for that hour – in most cases this is natural gas

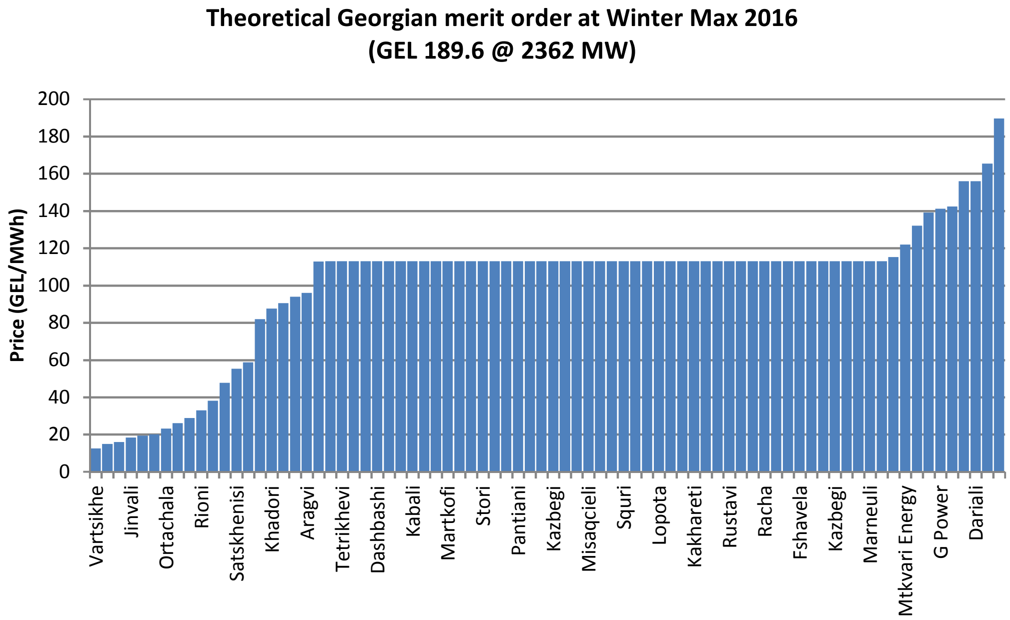


Figure 13: Simple merit order in Georgia at Winter Max hour conditions

With this approximation, based on publishable information[20] as well as expert estimates, the following values and generation prices may be representative for the Georgian system.

Table 14: Georgian electricity mix and average prices

	Annual Production & Imports (GWh)	Price (GEL/MWh)
Wind	11	165.36
Hydro	9194	12.5 to 156
Thermal	2159	90.56 to 189.6
Imports	479	139.2

Although, as previously mentioned, a reference electricity price may not be clearly identifiable in Georgia, the generation price ranges on Table 14 above offer a basis of comparison with proposed FiT under the Medium building-PV development scenario.

5.5 Congestion management

There are various and different bottlenecks in the Georgian system, which the TSO plans to alleviate through the investments considered in the TYNDP. All these challenges, which are described in detail in section 3.6 of the TYNDP, are considered independently of the development of building-PV. According to the TSO, PV output coincidence is not expected to affect congestions and contingencies that are currently present in the system. However, at an operational level,

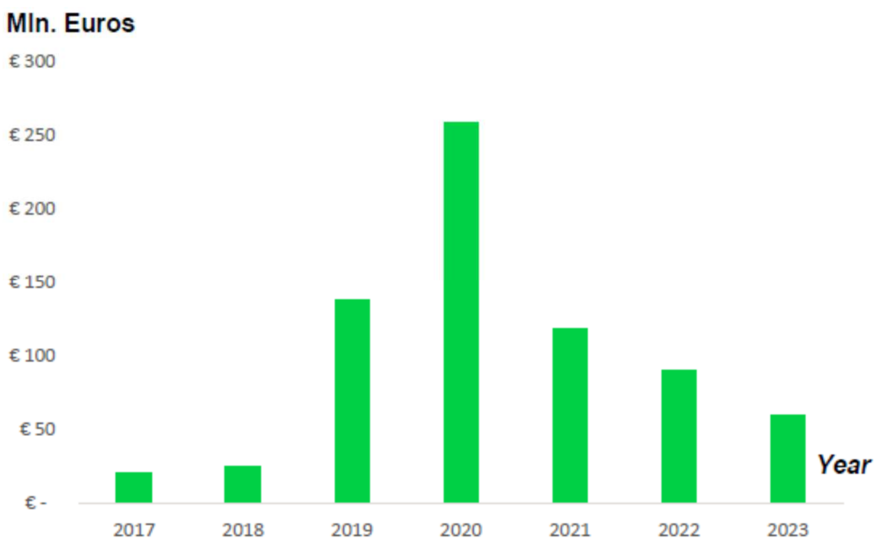
[20] GNERC Annual Report 2016 available at: http://gnerc.org/files/wliuri%20angariSi/GNRC_Report_2016_ENG_2017%2021.07.17.pdf

excessive hydropower generation, which normally exists in the Georgian system in spring time, may aggravate operational challenges, if PV generation correlates with low demand hours.

5.6 Infrastructure development

The Georgian TYNDP 2017-2027 provides for ca. € 750 million, for network development projects cumulatively in the period 2017 -2024.

Figure 14: Total investments for 2017-2023(source: Georgian TYNDP 2017-2027)



Nevertheless, these investments are a result of the planning exercise undertaken by the TSO, in order to fulfil the responsibilities placed on it by the local legislation (primarily the N-1 criterion). Though it can be mentioned, that in general each and every project that relates with the reliable offtake of small-hydropower plant output can be regarded as a RES integration-related investment, in reality there is still no dedicated planning devoted to PV generation, neither at utility scale level nor at distributed generation level.

The situation is similar with respect to the distribution network. It should be noted, however, that in this case there are no publicly available and well-documented distribution network development plans, for any of the three distribution regions. Network investments are annually approved by GNERC, as part of the tariff approval procedure, based on a predefined set of criteria including:

- Improving reliability of supply;
- Improving electricity quality indicators;
- Reducing losses;
- Compliance with requirements of safe operational conditions.

However, there is no separate criterion which may relate to the introduction of RES-based distributed generation, let alone PV in particular. According to GNERC's Annual Report of 2016, investments in the distribution sector have reached the overall amount of 82 million GEL for 2016.

5.7 Balancing cost

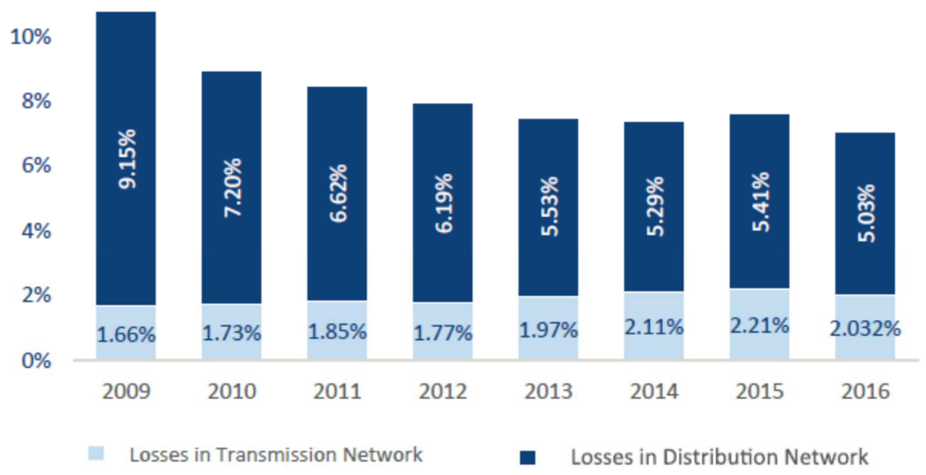
Currently in Georgia electricity traded through direct contracts comprises about 80%-90% of the total electricity trading (on the average, on an annual basis); the remaining 10%-20% of the total comprises "balancing electricity"[21], and is traded by ESCO through medium and long term contracts (under standard terms of direct contracts) on imports and exports. It is important to mention, that the current balancing practices in Georgia deviate from those that that can be monitored in most of the EU Member States and those rules implementing the balancing markets, as part of the EU Target Model, as it is in particular described in the Electricity Balancing Guideline (EBGL).

Therefore, it was impossible at this stage of the developments, to retrieve any electricity balancing cost indicators which may have been developed by the TSO, based on previous operational experience (e.g. €/MW of installed PV). In general, the current market balancing costs are implicitly covered through energy trading commercial agreements (either with generations or through import), which are recorded as deviations and are settled on an imbalance price, which in turn is determined on a monthly basis. Therefore, costs of balancing energy and reserves are neither identifiable in general, nor can they be attributed in any way to the presence of intermittent RES generation in the Georgian power system.

5.8 Losses

As it is illustratively depicted below in **Błąd! Nie można odnaleźć źródła odwołania.**, Georgia has achieved a remarkable development considering the increase of the performance of its electricity networks, with respect both to transmission and distribution.

Figure 15: Total actual losses in the Georgian electricity system (source: GNERC Annual Report 2016)



Like many other indicators discussed above, in the case of losses it is also impossible to isolate the effect of intermittent RES, evaluate their impact and possibly come up with some indicative benefits or costs that may appear as an impact of developing building-PVs in Georgia. Though there is experience in the EU, as it is discussed in section 2.4 of the "Review of EU Experience

[21] According to the Law, "balancing electricity - electricity (capacity) purchased and/or sold by qualified enterprises, which is used to meet actual needs of buyers and sellers, and to balance the contracted amount of the electricity stipulated in direct contracts".

with Solar PV in buildings” report, which relates the impact on losses with intermitted RES generation, it would be advisable that this is not taken for granted in the case of Georgia, given its network particular characteristics.

6 Conclusions

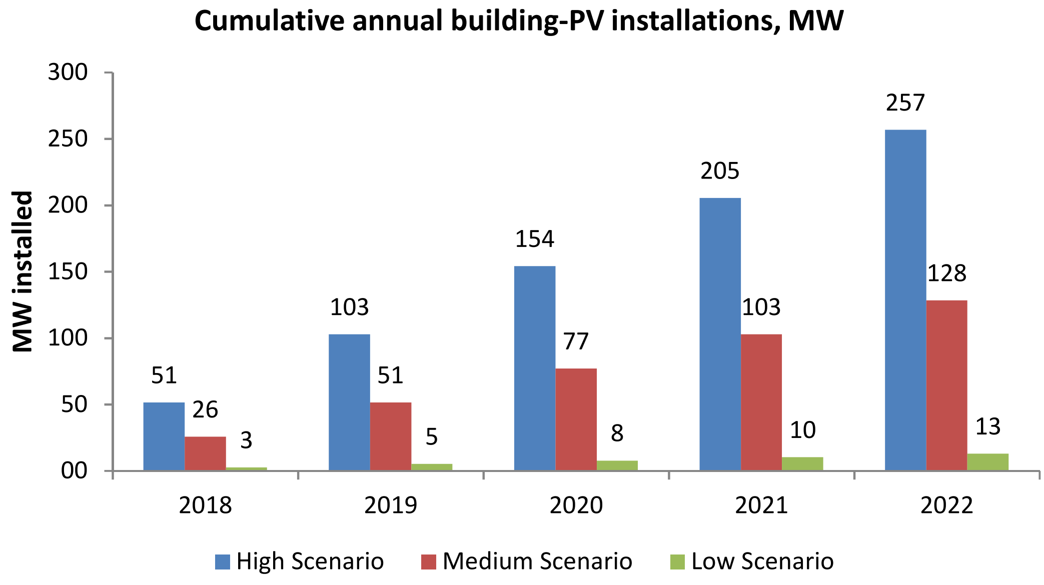
6.1 Main findings of the study

The main purpose of this component of the study has been to explore potential ways for building-PV deployment in Georgia, including development of scenarios of staged deployment in the future years and analysis and cost-benefit assessment of potential policy measures to be implemented in the country to support building-PV market uptake.

Analysis undertaken in the "Review of EU Experience with Solar PV in buildings" report of this study had suggested the implementation of specific policy support programmes tailored on building-PV deployment, to serve as a pilot to open up the market and allow PV system costs to decrease and the value chain to be created, thanks to a progressive deployment, market expansion and experience.

This report has taken a step further by developing three scenarios for increasing levels of building-PV penetration in Georgian cities over the period 2018-2022 associated to different levels of Georgian government commitment over building-PV deployment in the country following a simple yet evidence-based logic: the higher the commitment, the higher the policy support required for implementation (see Section 3.4 for more details).

Figure 16: Cumulative building-PV installations under three deployment scenarios, MW (2018-2022)



Deployment scenarios have been developed based on the potential PV capacity on buildings of four Georgian cities (Tbilisi, Batumi, Kutaisi, Rustavi) estimated in the "Quantification of the potential of building-PVs in Georgia and the rest of the Eastern Partner countries" report of this study. Figure 16 presents cumulative annual MW of building-PV installations assumed under the different scenarios: ranging from a very conservative Low Scenario where less than 3MW are year are installed to a more optimistic High Scenario under which about 50MW are installed every year.

Such scenarios are associated to the progressive increase of policy support through the implementation of (see section 3.4 for more details):

- Net metering scheme, as already in place in the country;
- Capital grants, defined as a percentage of the initial building-PV investment cost;
- Feed in Tariff scheme (FiT) offering a specified generation tariff for the total PV electricity generated, over a 20-year timeframe.

Main conclusions and takeaways from the end used and cost and benefit analysis of the above scenarios are as follow:

- Under current PV policy support framework, i.e. net metering scheme, financial attractiveness of building-PV investments is low due to the relatively low end-user electricity prices. Therefore at the current policy support level we do not foresee that a substantial building PV capacity to be deployed.
- Additional support is needed to make building-PV systems financially attractive.
- In our Low Scenario we estimate that an annual deployment of about 2.5MW could be achieved by implementing a 5 years capital grant programme (i.e. 2018-2022) which would cost about € 2 million per year, for a total of about € 9.5 million (spread over 5 years).
- We estimate that, assuming similar returns on building-PV investment, a FiT scheme would provide higher levels of deployment.
- Under Medium Scenario expected annual deployment would be 25MW a year, thanks to the implementation of a FiT scheme. The scheme would have an average annual cost of around €10 million and total cost over the lifetime of the programme (i.e. 24 years) of about €256 million. Such cost would be spread over the 24 years lifetime of the FIT programme, with annual cost increasing over the first 5 years, as new building-PV systems are installed each year and then progressively decreasing over time (see Figure 7).
- For an increased level of policy support under High Scenario (i.e. the implementation in parallel to the FiT scheme of a capital grant programme which would increase the profitability of the building-PV investments) higher levels of building-PV deployments are achieved: about 51 MW of annual installations over the 5 years period. The average annual cost of such policy measures is estimated at about €28 million, for a total of about €551 million, over the lifetime of both policy programmes. As in the case of the Medium Scenario above, such cost would be spread over the 25 years lifetime of the FIT programme, with the annual cost increasing over the first 5 years as new building-PV systems are installed each year, incentivised by the FiT scheme, and then progressively reducing over the lifetime of the programme (see Figure 8).
- If FiT scheme (both under Medium and High Scenarios) had to be financed by means of a RES levy, the overall potential economic impact on households' electricity consumers is estimated to be relatively low. However, potential adverse social redistribution effects must be taken in due care while designing the policy instrument (see Section 5.3).
- The calculated FiT policy cost (i.e. FIT scheme based on generation tariff) should be intended as the highest policy cost, whereas alternative designs of FiT combined with self-consumption scheme may result in a lower policy cost.
- The deployment of building-PV capacity in Georgia would bring environmental and social benefits which have been quantified in terms of CO_2 emissions achieved (ranging between 173,575 t/CO_2 under Low Scenario to over 3.4 million t/CO_2 under High Scenario) and jobs created (ranging from 424 jobs under Low Scenario to over 8,000 jobs created under High Scenario).

6.2 Next steps to be taken

One of the main conclusions derived from the Solar Study of the HiQSTEP project, is that PVs in urban areas can play a significant part in the development of the Georgian electricity market towards a more competitive, flexible and sustainable direction. Considering that the Georgian PV sector is still a niche market, being in its infancy, and having the experience from a series of EU markets it mind, it becomes clear that this cannot happen without a strategic plan which will implemented by means of specific policies and measures.

The rationale behind the policy measures examined in this part of the study and, eventually, proposed is to support the building-PV deployment under the different scenarios, in the form of implementing of a pilot PV policy support programme over a relatively short timeframe of 5 years, i.e. from 2018 to 2022. This would have the main aim of opening up the market and supporting the early stage development of the Georgian building-PV sector. As soon as this has been achieved, this pilot programme can then be followed by a new policy framework updated to account for the countries' PV market evolution in the first years.

Indeed, pilot PV policy support would allow scaling up of building PV deployment in Georgia and consequently to achieve the necessary cost reductions (both at technology and system levels) and development of the PV sector supply chain which would constitute the base for further PV market expansion in the country.

It can be envisaged that, after the 5 years programme, new and refined policy instruments to support building-PV could be implemented, taking stock of the achievements of the pilot programmes and inspired by PV policy evolution accrued in other European countries characterized by highly developed PV markets. The current European PV policy framework and numerous EU Member States are in fact progressively reducing FiT scheme support (in particular if designed in the form of generation based tariff, as assumed in this study) in favour of more 'market based' policy support more suited for already developed PV markets. In particular, EU PV policy support is increasingly designed in the form of premium tariffs and more emphasis is given to incentivizing local end users self-consumption. The premium FiT is in fact more in line with State Aid renewable energy guidelines 2014-2020[22], where it is asked to keep the incentive in the form of a *premium,* separated from the electricity component in order to integrate renewable energy into electricity markets[23]. It must be noted, however, that State Aid Guidelines currently allow FiT incentive mechanisms (not as a premium, but based on generation tariff, as in this study) when the PV system size is limited to <500kW[24]. In other world the FiT design proposed in this study as a pilot programme would compliant with State Aid regulation.

Although the issue seems to be very distant, in the long run, thanks to its good insolation potential, Georgia may face grid integration issues. A series of objective reasons have prevented us from developing definite and quantitative assessments on various costs and benefits of the potential impact of building-PV integration to the local distribution grids. However, a qualitative discussion

[22] Guidelines on State aid for environmental protection and energy 2014-2020 (2014/C 200/01) t

[23] Art 3.3.2.1 (124) In order to incentivise the market integration of electricity from renewable sources, it is important that beneficiaries sell their electricity directly in the market and are subject to market obligations. The following cumulative conditions apply from 1 January 2016 to all new aid schemes and measures: (a) aid is granted as a premium in addition to the market price (premium) whereby the generators sell its electricity directly in the market;

[24] Art 3.3.2.1 (125) The conditions established in paragraph (124) do not apply to installations with an installed electricity capacity of less than 500 kW or demonstration projects, except for electricity from wind energy where an installed electricity capacity of 3 MW or 3 generation units applies.

over possible impacts has been presented. Moreover, experience with distributed generation development has shown, that it is actually a multifaceted issue, involving a number of technical and regulatory decisions, which also in their turn imply decision-making interdependencies. Most importantly, the policy decision of developing distributed generation usually relates with the overall ambition for a decarbonisation of the electricity system, which is translated into a high level of RES penetration. Conversely, where certain conditions are not considered to be met (e.g. decarbonisation is not yet a strong energy policy driver and/or energy security is vulnerable and/or the level of grid preparedness is low), RES penetration often takes small and cautious steps - and should the investment climate allows to do so - they are usually realized at transmission network level. As it was also discussed in section 2.4 of the "Review of EU Experience with Solar PV in buildings" report, the level of understanding on the overall impacts of RES integration relates with the penetration rate and most importantly in the initial stages of development. This is often understood as an isolated issue relating only to the determination of hosting capacity, whereas operational and infrastructure impacts are usually neglected. Experience has however shown, that this should be treated with care.

Hence, the first decision which relates to the policy decision of developing distributed generation is whether the relevant grid impact shall be treated isolated (i.e. only for the distribution network) or not. In some countries that practice involved an isolated approach, which in effect had to do only with the assessment of hosting capacity. However, with the empowerment of electricity end-users and the development of competition in the retail segment of the electricity market such an approach may be revealed to be short-sighted. It is therefore generally proposed that Georgia benefits from the experience of certain EU member states and tackles the issue in its full extent and with due appreciation of the various conditions and parameters associated with an increased RES penetration on both the transmission and the distribution level.

Secondly, and if in particular the decision is to treat the subject collectively in respect of the impact to the transmission and distribution network, a TSO-DSO cooperation is imperative to be established. There is currently a growing debate in Europe on how TSO-DSO cooperation may establish common working rules for distributed flexibility, encompassing the TSO-DSO interface, data management, network fees and retail market integration of storage, empowerment and privacy rules for the customer, self-consumption and managing interactions between suppliers and independent aggregators. As soon as the fundamentals are established, TSOs and DSOs may extend their cooperation further in order investigate appropriate integrated solutions for balancing and congestion management, at both TSO and DSO levels.

Given that a study on intermittency analysis is currently at tendering stage in Georgia, an immediate enlargement of the scope of work may not be achievable. It can therefore be proposed, that the following aspects are taken into account in a possible follow-up study, ideally to be carried out with the participation of the country's TSO and DSO:

- **Hosting capacity:** The assessment needs to be initiated at distribution level, taking into consideration the effects of voltage rise on the feeders on which PVs are connected, cable loading and transformer capacity. Both stochastic and deterministic methodologies may be engaged for the assessment. Results at city's level need to be checked at transmission level, thereby checking the network element operational limits via load flow and short-circuit studies.
- **Market impact/generation displacement:** This assessment needs to be performed through an hourly dispatch simulation, taking into account must-runs, dynamic

characteristics of the other generators in the system as well as the load forecast. Resulting scenarios should then be checked for their validity by load flow simulations

- **Infrastructure development:** relates with both DSO and TSO assessment of either avoided network cost (i.e. if valid generation scenarios are able to postpone or even cancel required network expansion/reinforcement or rehabilitation) or, in the opposite case, dedicated network projects required for the timely connection of future RES projects
- **Balancing cost:** Though balancing cost may be unavoidable, it is always for the benefit of the optimisation of power system operations that the TSO is aware of the reserve needs which emerge with the increased penetration of RES. This assessment is useful, in order to establish that imbalances caused by a market party are taken care of by the same party in a fair and transparent manner. In addition, such an assessment can also help in the determination and improvement of weather forecasting services required for scheduling. Last but not least, such a study may help in decisions to be made in the wholesale market design, such as the operation and determination of Programme Time Units (PTU) in the intra-day market.
- **Losses:** They require a harmonically arranged TSO-DSO cooperation, particularly if the supply/demand conditions in the network are such that reverse power flows from distribution to transmission become evident. Though this usually happens in cases where large distributed generation penetration margins have emerged (for instance in Denmark or some regions of Portugal), it may as well be part of the assessment in Georgia, in times where the seasonal discharge of run-of-river hydros reach their maximum, while the demand remains at relatively low levels. Especially referring to the economic impact of losses forecasting, this can be of a particular value for the Georgian network operators where losses are procured at a centralised level since proper planning should prevent losses forecasting errors.

6.3 Recommendations

In that sense, the Georgian government should take the political decision to adopt building-PVs and express this decision in form of short- to medium-termed strategy. As it has been indicated by this study, an effective policy aiming at a substantial presence of PVs (the Medium or even the High Scenario) can be implemented, without an excessive strain being placed on the grid, without excessive costs for the national economy and, given due care is paid to the regulatory aspects, without leading to unacceptable cost transfers to the weakest consumers. Key issues for the effective promotion of the specific, small-scale technology are the following:

- Organisational innovation[25] is key for the design and implementation of an appropriate programme for the development of building-PVs. Given that the proposed programme is proposed to be led by a Georgian public institution, organisational innovation shall be regarded as the process of ensuring project aggregation and financing solutions minimising transaction costs and engaging the (international and/or private finance community. It would also include the removal of legal, administrative and other market barriers for bringing the specific investment pipeline to a financial close (possibly following the proposed staged development if they are in agreement the plans of the partner financing institutions). This calls for regulatory and administrative actions, which can only

[25] http://ec.europa.eu/eurostat/statistics-explained/index.php/Glossary:Organisational_innovation

be undertaken by Georgian administration. The Ministry of Energy is the key stakeholder, although it obviously also will have to act as a focal point for other authorities as well.

- Access to improved financing is key for the development of the programme. In our view engaging with the IFIs is crucial with the view to increase financing for instance by exploring the possibility of or the extent to which aggregation and standardisation of financeable solutions is feasible. In this respect the present report can act as the introductory study on which the IFIs may base their own assessments and eventually come up with their own specific solutions.
- When it comes to the specific polity tools required, a Feed-in-Tariff appears to be the more appropriate instrument, since it would reduce investment risks and provide the necessary basis for the engagement of financing institutions.
- FiT scheme could be financed by means of a RES levy, thereby the cost would be charged and passed on to the final electricity consumers. However, care should be taken in designing and implementing the scheme to avoid excessive burden on end-users and adverse social redistribution effects (possible measures are proposed, see also discussion in Section 5.2.2 and 5.3).
- The implementation of capital grant scheme (or alternatively soft loan scheme) in conjunction with FiT scheme might help final end users to overcome access to capital barrier, thus facilitating investments and guaranteeing higher levels of building-PV deployment.
- Capital grant and soft loan schemes could be financed through specific International/Multilateral Financing Institutions' programmes, due to both their relatively small total cost and the fact that their cost burden is limited to a few years, compared to FiT which requires longer term commitment.
- It would also be appropriate to promote building-PV also via other policy mechanism such as obligation to install building-PV in new building development in percentage of expected building final electricity consumption. This will scale up building PV market on the basis of an obligation and not an incentive thus reducing long term policy cost.

Overall, the successful development and implementation of financing and regulatory tools calls for the very effective co-operation between the government, the IFIs and the national financing institutes. The initiative lies, again, with the Georgian administration. Still, the EU experience obtained over the years in similar situations, can be a useful asset.

Of the deployment scenarios developed we believe that the medium scenario would lead to reasonable addition of building capacities, if it is adopted by the Government of Georgia as an element of the ongoing discussion on the Georgian National Renewable Energy Action Plan.

We would therefore propose to develop a national programme for building-PVs, which will comprise the following characteristics:

1) Its overall capacity target is in line with the policy objectives. It needs to be both ambitious and relevant. This HiQSTEP Buildings Solar Power study provides for 25 MW over a 5 year horizon (i.e. 5 MW target per year)
2) A national focal point is designated for the promotion and administration of the programme. Based on an agreement between the Ministry of Energy and Ministry of Economy this may also be the mandate of an Agency responsible for Renewable Energy & Energy Efficiency in Georgia. Existing structures can be utilized (such as for instance the Georgian Energy Development Fund or the Georgian Municipal Development Fund), whilst capacity building can be supported by the EU, through TA and TWINNING projects.

The Agency's mandate shall include, among others, the preparation of the programme (i.e. possible budget constraints, methodology for funding the programme, main target group –households, businesses, public sector etc.-, minimum specifications for the PV systems in cooperation with the DSOs, negotiation and agreement with International and national financing institutions for the financing of the additional cost of FiT, streamline procedures with the competent authorities, disseminate the programme, etc.) as well as monitoring its development regarding the achievement of targets and , most importantly, the respect of budgetary constraints

3) Once the programme characteristics become solid and for the purposes of launching the programme, the legal framework has to be established, by means of respective legislative acts (Ministerial Decree, Decision or equivalent)

Concluding, we would like to highlight the following points, which should be kept in mind when making the decision on the above-proposed programme:

1) It is vital to ensure the support at the Government of Georgia level (including the Ministry of Finance and the Regional Development and Infrastructure, etc.) as appropriate on the structure and extent of the programme (or possible variations based on local specificities e.g. national vs regional/municipal programme(s) and/or inclusion of off-grid communities)
2) A discussion with the European Commission is crucial, as it can probably provide further assistance on this programme, in the frame of Eastern Partnership or other suitable cooperation mechanism.

A preliminary scoping discussion should be carried out, with national and international institutions, to fathom their interest to participate in the programme and to determine their possible role (e.g. providing competitive loan terms, streamlining loan procedures for the programme)