Electrical Network Efficiency Improvement

RD&D Project No. 73: Support Scheme for PV Solar

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NovoGrid Ltd

Contents

Executive Summary

The objective of this project is to inform the policy consultation process concerning the design of a renewable energy support scheme for photovoltaic (PV) solar generators.

As PV solar is a rapidly evolving technology incorporating the impact of future technology innovations is critical to the success of any support scheme.

NovoGrid have developed a novel control system, called AVA, for PV solar generators that enables them to reduce energy lost as it's delivered via the electrical network. This would directly impact the PV solar generators net profit via an increase to its annual output.

A detailed power flow analysis of AVA's impact was conducted on a typical PV solar generators of 5 MW. An improvement of 0.6% increase in the generator's annual output was observed from the studies via a reduction in electrical network losses.

A recent KPMG report projected that 800 MW of utility-scale PV solar generation could be built in Ireland by 2020. Scaling the results from the power flow analysis up to this level showed a potential 5,003 MWh per annum reduction in losses.

Further economic analysis suggests that this increase has a potential value of €286,000 in terms of production cost savings. AVA has the potential to reduce CO_2 emissions on the island of Ireland by 1.6 kTons.

The financial impact of three different support scheme types were analysed:

- Feed-In-Tariffs / Feed-In-Premiums (FIT/FIP)
    - All generators receive a fixed price per MWh, which is set by the government
- Auction Mechanisms
    - Generators bid to build with the lowest priced bids receiving long-term government backed contracts
- Investment Tax Credits (ITC)
    - Generators receive a tax credit against capital expenditure

All three support schemes were assessed by their impact on the financial viability of a typical PV solar generator and by their net cost to the taxpayer. A comparison to a scenario in which AVA was installed on the PV solar generator and it received a 0.6% improvement to its annual output was conducted.

It was found that an Investment Tax Credit provided the best value for money to the taxpayer.

5 MW PV Generator AVA Installed	FIT/FIP @ €126/MWh	ITC @ €94/MWh	Auction @ €125/MWh
Investment Tax Credit	€0	€1,568,000	€0
Subsidy Revenue	€3,974,315	€2,045,574	€3,914,042
Tax Paid	-€179,642	-€135,663	-€173,580
Net Cost to Taxpayer	€3,794,673	€3,477,911	€3,740,461

Scaling up to 800 MW by 2020 the NPV cost to the taxpayer of the ITC support scheme is €361,484,352. A reduction of €169 million compared to the FIT/FIP reference scenario.

Introduction

The objective of this project is to inform the policy consultation process concerning the design of a renewable energy support scheme for photovoltaic (PV) solar generators.

The International Energy Agency (IEA) recommends schemes be designed to incorporate future technology innovations.

This project provides an evidence-based analysis of the added value PV solar generators with an innovative new technology can deliver to Irish energy customers.

NovoGrid have developed an intelligent control system, called AVA, which enables PV solar generators deliver more energy by minimising thermal impacts on the electrical distribution network.

The impact was assessed under three headings:

1) Technical
    a. Using power flow analysis of a PV generator to quantify the impact of AVA in MWh on output
2) Financial
    a. Model the impact of the additional MWh output on PV project financial viability
    b. Perform scenario analysis on potential support schemes
3) Economic
    a. Quantify the CO2 emissions and system production costs offset by the displacement of fossil fuel generation

The outcome of this report is to identify which of the potential support schemes best incorporates the value of AVA, fulfilling the IEA recommendation and providing the best value to Irish energy customers.

Overview of Project Methodology

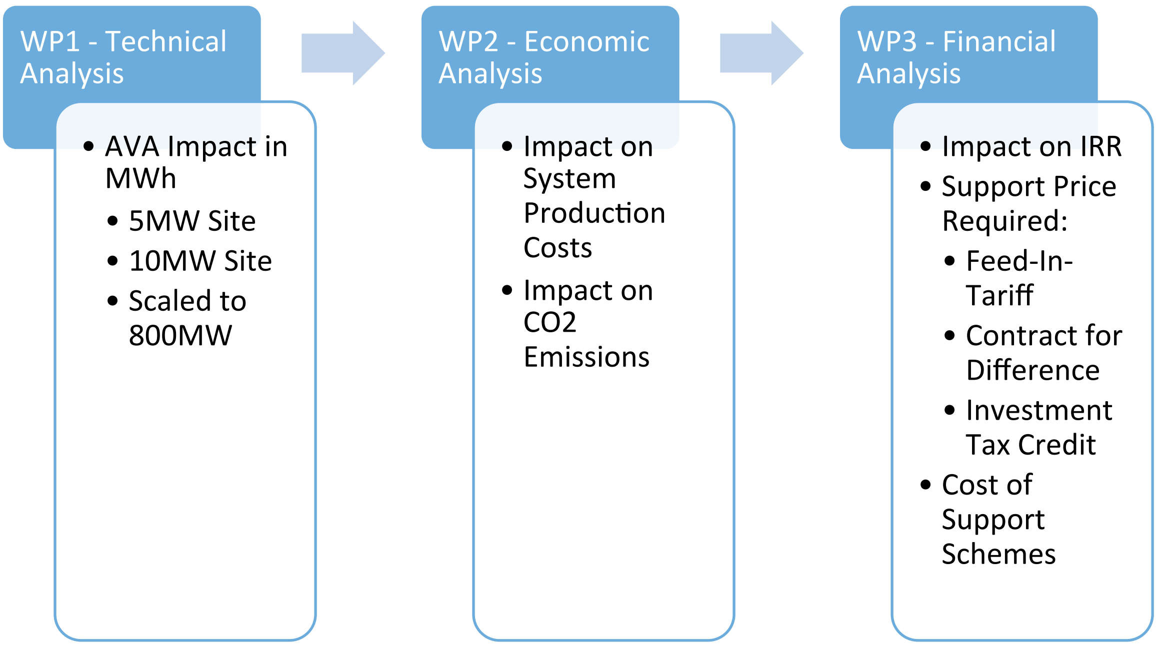
Work Package 1 (WP1) consisted of technical power flow analysis of the impact of AVA on the power output (Megawatt Hours, MWh) of two sizes of distribution network connected PV solar generators in Ireland. A 10 MW Type C and the more common[1] 5 MW Type D.

A recent KPMG report[2], for the Irish Solar Energy Association, indicated a target of 800 MW of ground-mounted, utility-scale PV solar generation in Ireland by 2020. Using this target figure the results from WP1 were scaled up to provide a national impact on energy demand for Work Package 2 (WP2).

WP2 analysed the impact of the change in energy demand on the Irish system production costs and CO2 emissions using the Epiphron production cost model.

Work Package 3 (WP3) used the outcome from WP1 to model the impact on the financial viability of a 5 MW under a range of potential support schemes. A minimum support price per MWh required to meet an investment hurdle rate Internal Rate of Return (IRR)[3] was identified for each support scheme type.

Similarly to WP1 and WP2 these results were then scaled up to 800 MW by 2020 to calculate a total cost to the taxpayer of the various support scheme types.



[1] 95% of PV solar planning applications are for 5MW generators
[2] KPMG – A Brighter Future, The Potential Benefits of Solar PV in Ireland
[3] Unleveraged IRR hurdle rate of 7%

Work Package 1 – Technical Analysis

Power Flow Studies

Active Power Loss Reducing Technology

NovoGrid Ltd. patent pending technology uses local measurements at the point of connection of a generator to infer remote system conditions and calculate an optimal mode of operation to maximise energy export and reduce energy losses on a remote section of network. This technique ensures the local voltage constraint at the point of connection of the generator is adhered to while simultaneously minimising congestion of the connected network without any form of communication. With less congested lines on the network, less current will flow which ultimately reduces the energy losses on these lines while actually maximising the active power generated. Utilising the set points calculated by the loss reducing technology increases the efficiency of the existing assets in transmitting active power.

Method

This work determines the energy losses attributable to the future connection of photovoltaic generation in Ireland. In a time series power flow the capability of the novel technology to minimise network losses is utilised. The technology determines the desired set points for a generator to maximise energy export and minimise energy loss on remote lines on the connected network. These results are compared against a base-case scenario representing the normal mode of operation of distributed generation of this kind in Ireland. Energy savings in MWh that are made on the connected networks are determined.

The Irish Distribution Code [1] stipulates the reactive power capability of distributed generators above 5 MW of capacity. The reactive power operation is restricted to fixed power factor mode in the case of generation below 5MW.

Connection Types

In the distribution code[4] the connection of distributed generation is categorised into one of five groups, these are Connection Types A – E, illustrated in Fig. 1. Though created for the connection of wind generation, this study maintains the definitions for the connection of PV generation.

Distributed generation above 5 MW are categorised into one of five groups, these are Connection Types A-E, representing the extent to which demand customers are in the electrical vicinity of the connection. Type A connections are on the high voltage network connecting with other conventional generators on the 110 kV transmission system. Type B connections have dedicated feeders to connect to dedicated (≤38 kV) distribution system operated transformers that do not serve demand. Type C are similar to Type B, however the 38 kV busbar also services demand connections. Type D and E are electrically equivalent connecting to 38 kV, 20 kV or 10 kV feeders that serve demand and host generation. The distinction between Type D and E is in the physical connection to the feeder: a busbar for Type D and a tie-point for Type E.

[4] ESBN, "Irish Distribution Code," 2015. [Online]. Available: https://www.esb.ie/esbnetworks/en/downloads/Distribution-Code.pdf. [Accessed: 01-Jul-2015].

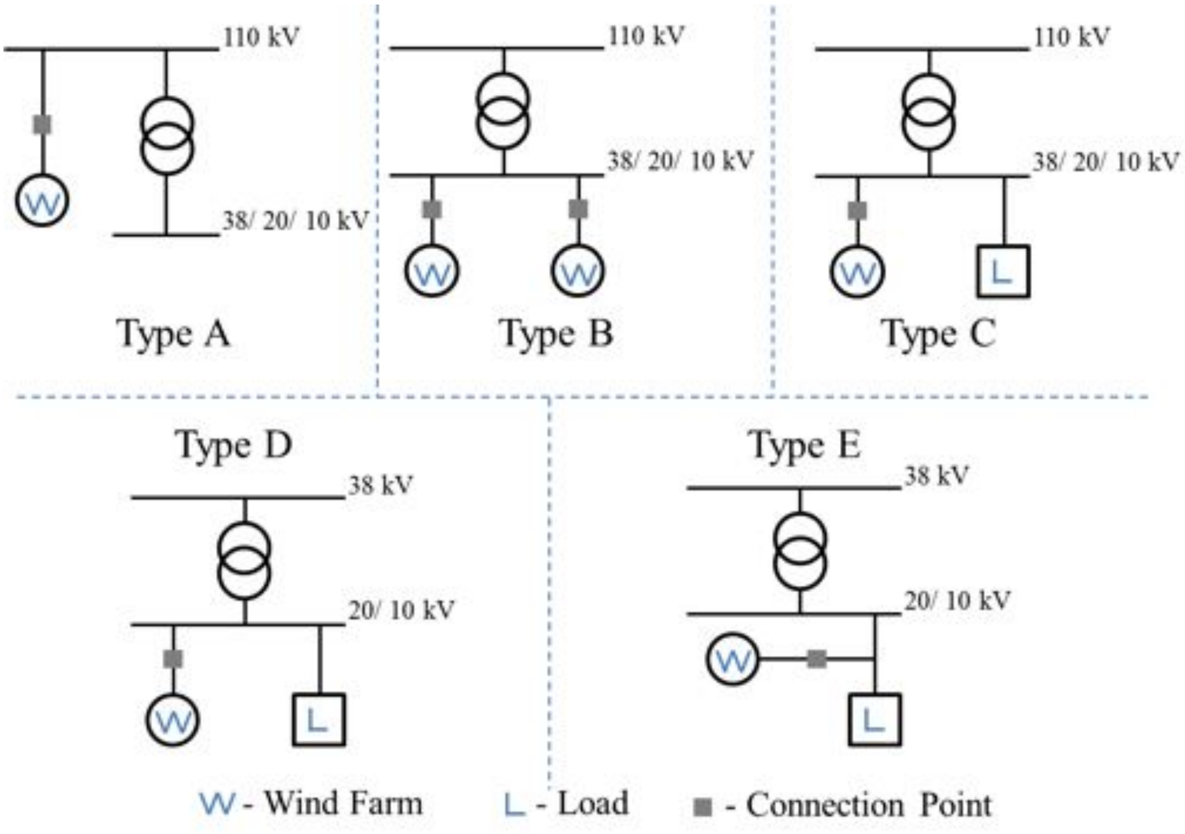


FIGURE 1: WIND FARM CONNECTION TYPES A – E

In order to determine the impact on losses of the system wide adaptation of the active power loss reducing technology, it is important to capture the distinct features of these connection types. Varying series reactance to series resistance (X/R) ratios change the behaviour of power flow through the branches of a power system and contributes to the voltage rise effect. The presence of load connected customers on the network changes the direction of power flow and affects the voltage dropped along a feeder. The presence of an on load tap changer (OLTC) transformer regulating the sending end voltage will influence the downstream voltage along the feeder.

With that in mind the reduction in energy losses achievable will vary depending on the connection type. The percentage breakdown of connection types assumed for the Irish power system is shown in Table I. These proportions will be used to exemplify the time series power flow studies to a system wide roll out of the active power loss reducing technology.

TABLE 1: PERCENTAGE OF GROUND MOUNTED PV BY CONNECTION TYPE

Connection Type	A	B	C	D/E
Percentage [%]	0	0	5	95

Representative Networks

For Connection Types C, D and E separate networks are modelled, fit for purpose to represent the various intricacies of each connection type. In this work Connection Types D and E have been amalgamated as, from a modelling perspective, their make-up is identical. The physical difference between the two is that for Connection Type E a tie-point is fit to connect the wind farm to an existing network, for Connection Type D this connection happens at an existing busbar. However, though physically different, the mathematical representations are identical; for a Connection Type D and Connection Type E with the same capacity wind farm and the same line lengths the structure and values of the mathematical models are identical, as in both cases a node is defined at the point of connecting the wind farm to the wider network.

Table II details the lengths, reactance and resistance used for the lines of each representative connection type. Also displayed are the installed solar capacities and rated operating voltages. The choice of installed solar capacities for each representative network anticipate the expected size of installations that are feasible without upgrading existing supply transformer MVA ratings.

TABLE 2: LENGTH, RESISTANCE AND REACTANCE OF REPRESENTATIVE NETWORK MODELS

	Branch	Length [km]	Resistance [Ω]	Reactance [Ω]
Type C 10 MW 110/38 kV	L0102c	4.2	1.550	1.642
	L0103c	12	6.312	4.824
	Trafo 38/110 kV	-	0.450	19.350
Type D 5 MW 110/38/10 kV	L0102d	7	2.583	2.737
	L0203d	11	4.059	4.301
	L0204d	8.5	3.313	3.324
	L0506d	5	1.136	1.859
	Trafo 10/38 kV	-	0.06	1
	Trafo 38/110 kV	-	0.450	19.350

Connection Type C

Fig. 2 displays the Type C connection; a 10 MW PV connected to a 20/38 kV transformer modelled 12 km away from the transmission system substation. A 38/110 kV transformer connects this network to the wider transmission system. The transformer regulates the sending end voltage to 1.05 pu in discrete taps with a +/- 10% deadband. Demand is present on this network on a feeder separate to the wind farm connection but connected back to the same 38 kV substation.

Connection Type D

In the models representing the Type D and Type E connections a 5 MW PV installation is embedded in the network, feeding into a 10/38 kV transformer. An 11 km OH line connects this bus to a node where demand is present elsewhere in the network. A 38/110 kV transformer connects this network to the wider system. The transformer regulates the sending end voltage to 1.05 pu in discrete taps with a +/- 10% deadband. Demand is present both on the feeder connecting back to the same 38 kV substation. This network is also illustrated in Fig. 2.

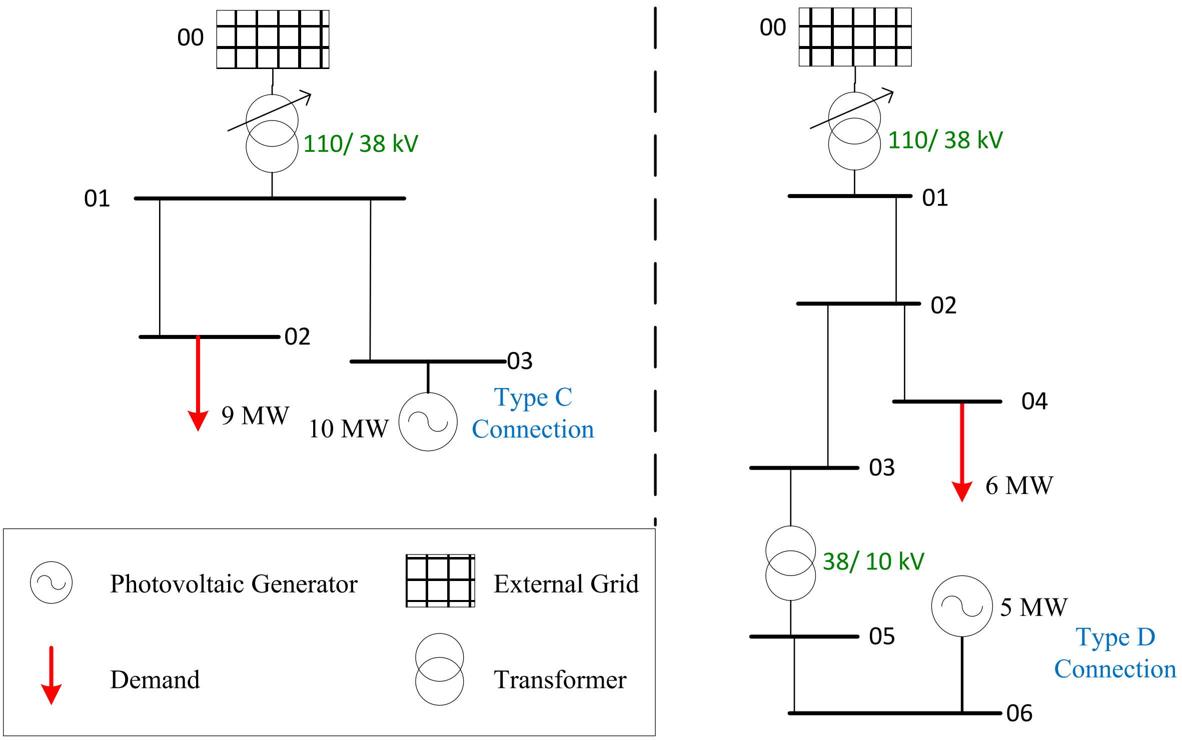


FIGURE 2: REPRESENTATIVE CONNECTION TYPES C AND D

Modelling

The custom-built representative network models are assessed in turn using a yearlong time series power flow simulation with hourly resolution. The network models capture the typical conditions the various connection types are prone to experience. The parameters of the conductors and lengths involved the nature of the transformer tap control, the demand level and rated voltages have been chosen as representative cases for each connection type. The assumptions made here attempt to embody each connection type into one representative network.

Energy Production from PV and Demand Profiles

NREL, the national laboratory of the U.S. Energy Department, have developed an online calculator to estimate the amount of electricity produced by a grid-connected photovoltaic system[5] . This online platform, PVWatts®, can take solar resource data from weather stations throughout the world as an input. Using solar irradiance data from Valentia weather station in Co. Kerry hourly active power output estimates for a year were synthesised. The estimate ground mounted PV output for one year is shown in Fig. 3 as a percentage output of active power. Peak output above 85 % of capacity occurs between April and August.

[5] PVWatts, “PVWatts Calculator” 2016 [Online]. Available: http://pvwatts.nrel.gov/pvwatts.php

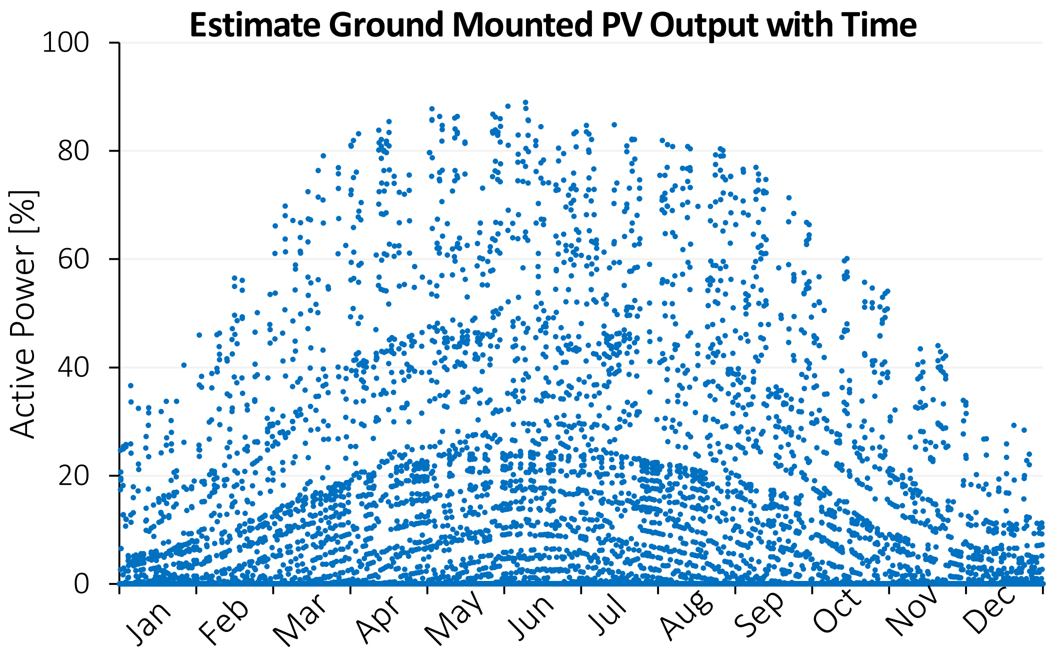


FIGURE 3: ESTIMATED ACTIVE POWER OUTPUT FROM PV IN IRELAND

In Fig. 4 the estimate active power output is shown by the hour for each day of the year, as seen the output ranges from 5 – 90% at mid-day. The capacity factor of these generation profiles is calculated to be 11.25, this is in line with the average capacity factor recorded for the UK[6]

This generation profile is used for each network model under investigation. Where applicable, on networks with load, a scaled version of system demand for a year is used to govern the level of demand in each hour.

Looking to 2020 it is anticipated that up to 2000 MW of installed PV would be connected to the Irish distribution system. The majority of this, some 800 MW, is modelled in these studies as ground mounted technology with either a Type C or D connection to the distribution system. The remainder is assumed to be residential solar installations.

[6] UK Dept. of Energy & Climate Change: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/547977/Chapter_6_web.pdf

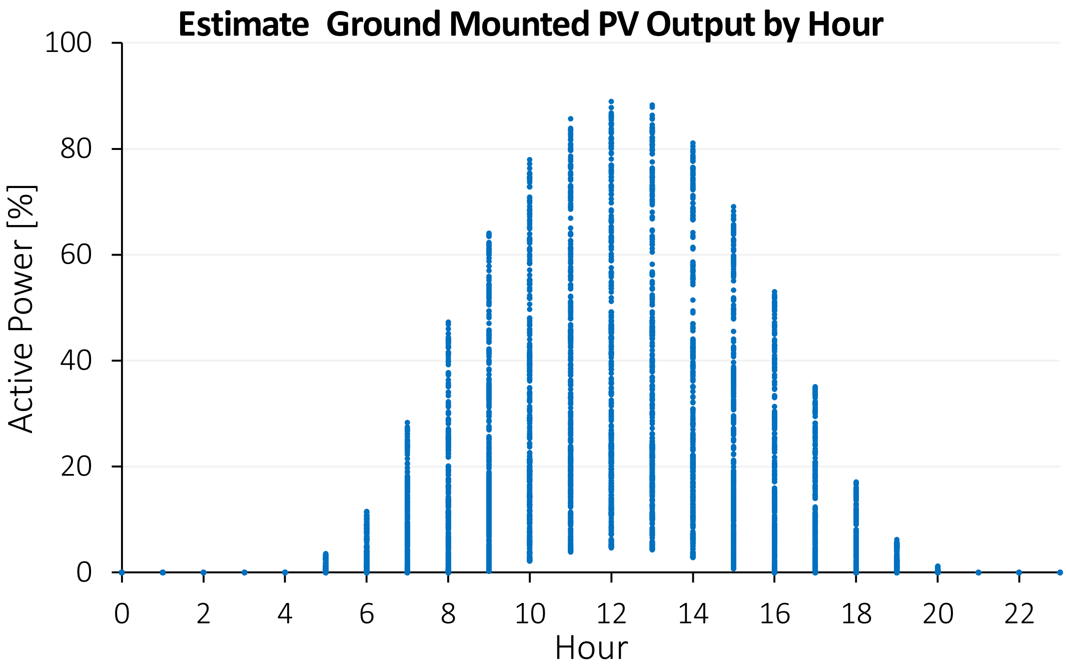


FIGURE 4: ESTIMATED ACTIVE POWER PRODUCTION FROM PV IN IRELAND BY HOUR

Results

The representative network models are used in a time series power flow, comparing the a 0.95 inductive power factor at the generator point of connection against the set points determined by the loss reducing technology for each time step. The calculated set point accounts for changing demand and any tap setting to autonomously maintain an optimal mode of operation. Local measurements are monitored in each time step, whereby an estimate of current flow is brought to its lowest possible value in the confines of the voltage constraints. Synthesised PV generation data and scaled demand profiles from 2015 are used in the simulation with hourly resolution.

Line Current Reduction

To demonstrate the ability of the controller to reduce current flow, two lines have been selected from Connection Types C and Type D. Figures 4 and 5 displays the current flow calculated on these two lines for a week long period. In this week, PV generation fluctuates daily from close to peak output for 4 of the days to less than 30 % capacity in the last two days of the week.

Figure 4 shows the current flow along Line 0103c from the Type C network, a connecting line for the 10 MW PV installation. The dashed red line represents the resultant current with the loss reducing technology present and the solid line shows the current resulting in normal inductive mode of operation.

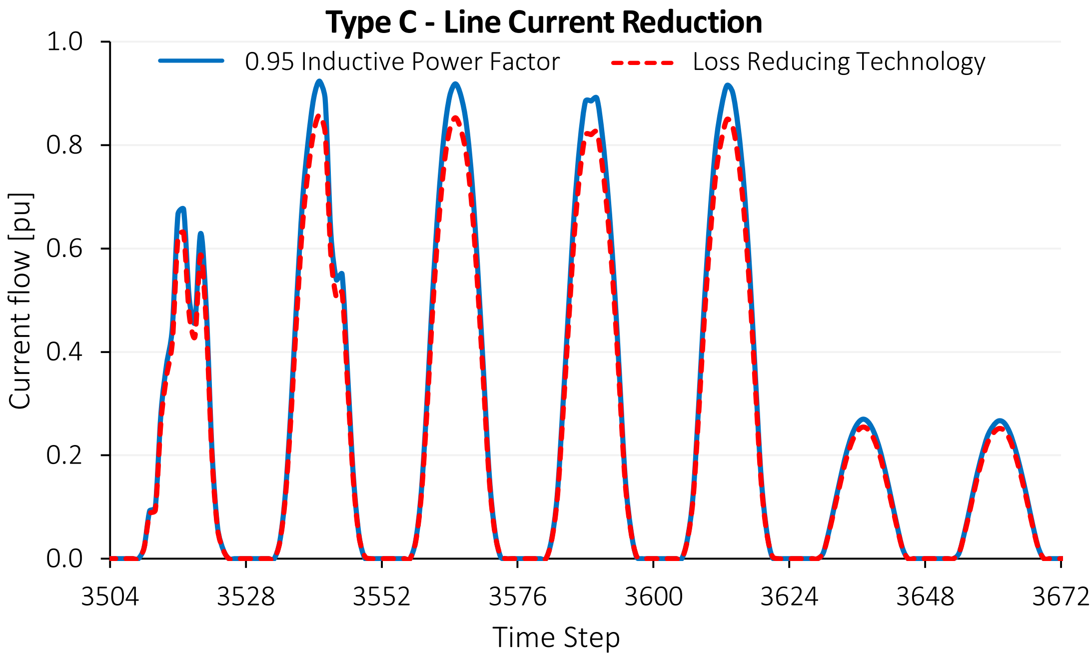


FIGURE 5: COMPARISON OF CURRENT FLOW FROM THE BASE CASE ON LINE 0103C

At all times when the PV generator had active power output lower currents were found to flow when compared to the base case inductive power factor mode. The largest reduction in current is apparent at times of high solar irradiance at mid-day for each day. These results are achieved without breaching the voltage bounds imposed on the network.

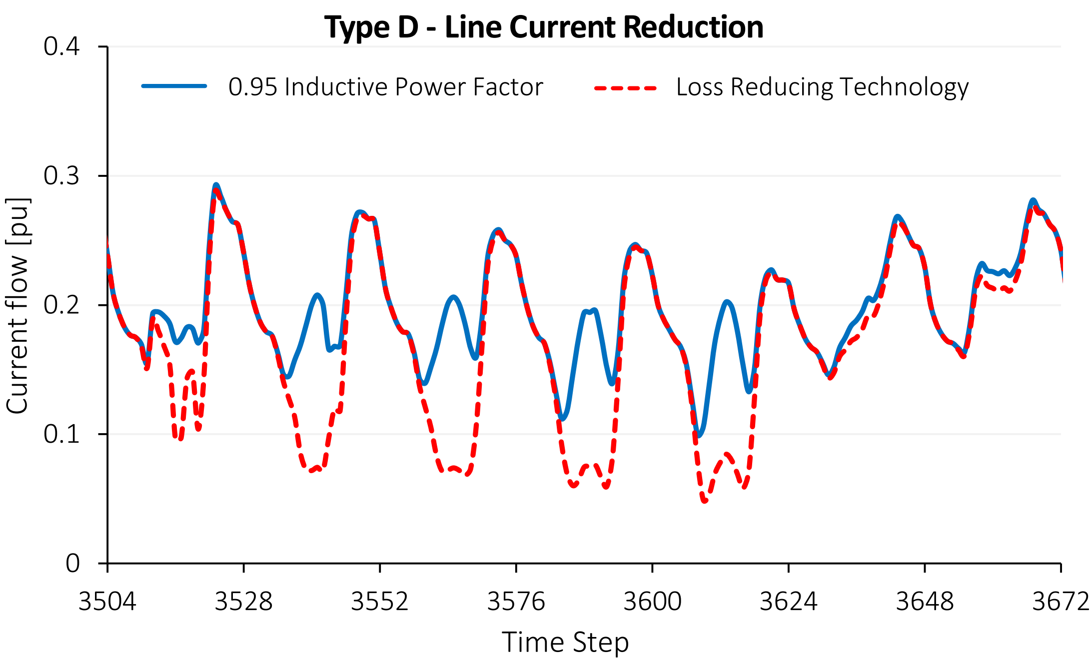


FIGURE 6: COMPARISON OF CURRENT FLOW FROM THE BASE CASE ON LINE 0102D

Figure 6 displays the current flow along Line 0102e from the Type E network, this line connects a transformer to a node where demand customers are supplied and also a connecting line for a wind farm is present. Once again the dashed red line representing the resultant current with the loss reducing technology present is at all times lower than the current found to flow in the base case inductive power factor mode when generation occurs. Notably, from this plot the technology can be seen to positively influence the current flow in a network where demand is fluctuating daily.

The actions of the loss reduction technology resulted in the reduction of current flow in the lines and transformers modelled in every hour of the time series power flow simulation. By reducing the current flowing in connecting lines of the PV installations and the lines of the wider network, the active power losses will reduce. This enables greater energy export from the PV connection lines and improved efficiency of the existing network infrastructure.

Active Power Loss Reduction

Table III shows the reduction in losses in each component for each network model, shown in absolute terms and as a percentage reduction from the base case with an inductive power factor.

TABLE 3: BREAKDOWN OF THE REDUCTION IN LOSSES BY CONNECTION TYPE FOR THE YEAR

		Reduction in Losses		Total Losses
		Loss Reducing Technology		Power Factor Mode
Type C 10 MW	Line	MWh	%	MWh
	L0102c	0.00	0.00	295.84
	L0103c	45.00	11.19	402.02
	Trafo 38/110 kV	1.95	3.64	53.59
	Total	46.95	6.25	751.45
Type D 5 MW	Line	MWh	%	MWh
	L0102e	8.83	5.88	150.20
	L0203e	4.41	14.69	30.02
	L0204e	0.00	0.00	223.46
	L0506	17.80	14.68	121.27
	Trafo 38/ 10 kV	0.24	5.96	4.03
	Trafo 110/ 38 kV	0.46	3.77	12.19
	Total	31.74	5.87	541.17

Across both connection types there is a reduction in losses seen in the connecting lines of the PV installations, this serves to promote the new DLAF 2.0 Mechanism. In addition to these lines, the network active power losses reduce on the surrounding lines and transformers of the wider system, benefitting all electrical network users. The percentage reduction in losses achieved by this technology is significant. In the representative network models the total percentage savings range from 0 – 15% depending on the connection type.

The breakdown of the losses in each component gives further insight into the potential for energy loss savings. In the most notable instance a 14.69% reduction was achieved for an overhead line simulated in the Type D model. Overall the active power losses reduced by 5.87% for this Connection Type.

Examining the active power loss savings by the hour reveals further the extent of loss reduction possible. Fig. 6 and Fig. 7 show the percentage reduction in losses for the Type C and D connections in each hour of the year for the Lines 0102a and 0102d respectively. Also displayed in both figures is the average percentage active power loss reduction of these lines for each hour of the year.

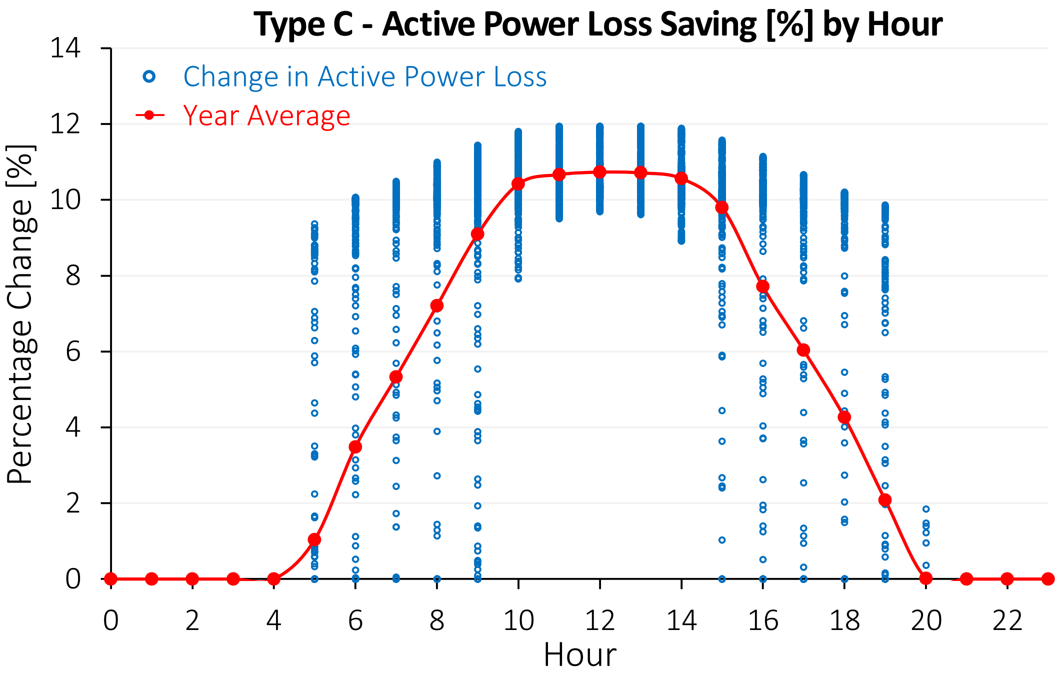


FIGURE 7: TYPE C 10 MW PV INSTALLATION - ACTIVE POWER LOSS REDUCTION ON LINE 0102C BY HOUR

At times of peak active power output the loss saving technology resulted in a range of 9 – 12% reduction in losses for the type C connection and a range of 2 – 88% reduction in the case of the type D connection. The vast range of percentage loss reduction observed for the Type D connection is attributable to the interaction of oscillating generation and varying demand conditions on the feeders of this connection type.

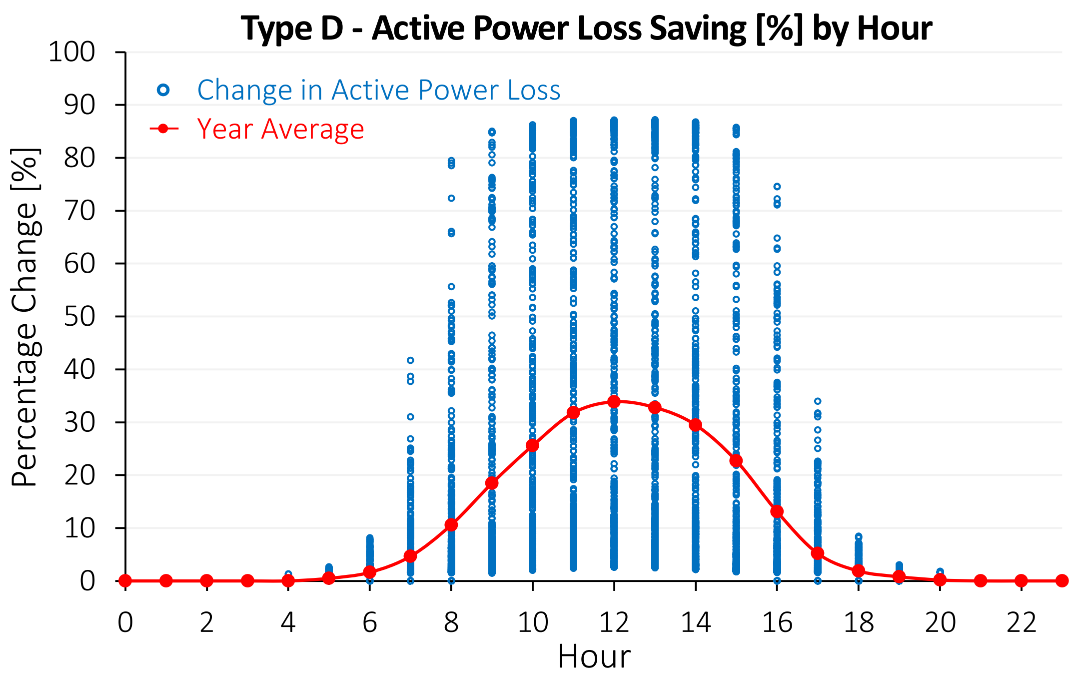


FIGURE 8: TYPE D 5 MW PV INSTALLATION - ACTIVE POWER LOSS REDUCTION ON LINE LINE 0102D BY HOUR

Average annual reductions for this peak hour came to 11% for the 10 MW Type C connection and 35% for the 5 MW Type D connection. No loss savings occur at night.

The results from Table III are used to determine the total reduction in active power losses possible for a system wide use of the loss reducing technology. The installed capacities of each connection type have been estimated in Table I and are used here to scale the reductions in the representative models to a system wide case. Fig. 7 shows the MW reduction by hour scaled to the system wide adaptation of 1800 MW of ground mounted solar installations using the loss reducing technology. Also displayed is the average MW reduction in each hour over the course of the year. As seen, while peaks of over 10 MW occur, the average peak value in a given day comes to 2.4 MW.

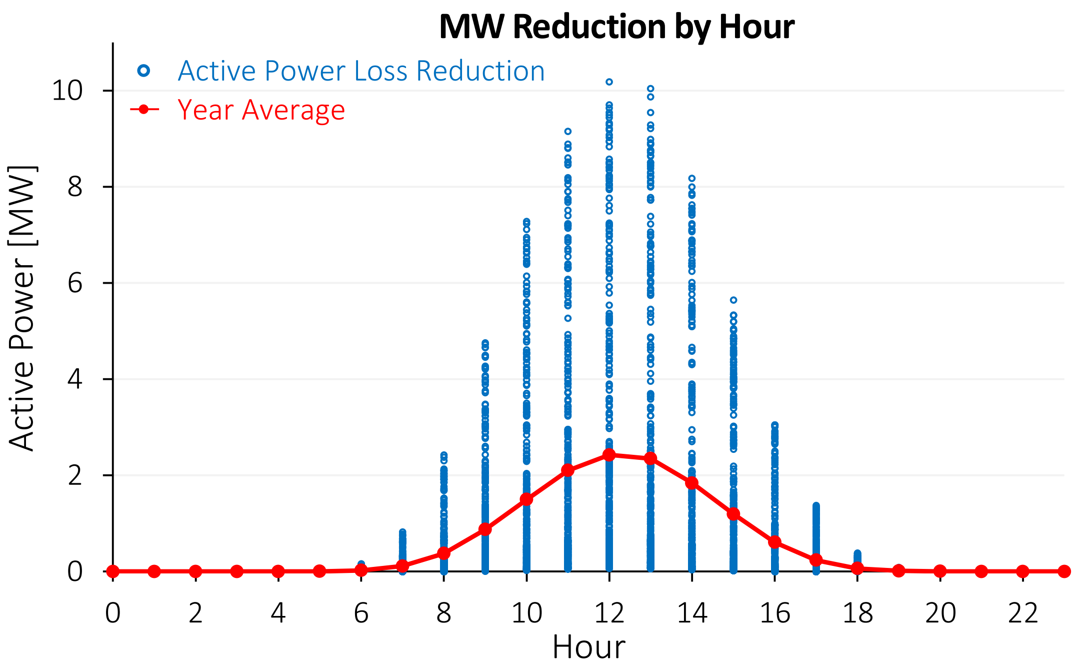


FIGURE 9: SYSTEM TOTAL ACTIVE POWER LOSS REDUCTIONS BY HOUR

Table IV shows the reduction in active power losses per MW of installed Connection Type for a time series power flow simulation modelled with the synthesised PV data for the Irish Case. Also shown in the table is the scaled version of the MWh reduction for a system wide case.

TABLE 4: REDUCTION IN LOSSES [MWH]

	C	D
Per Type	46.95	31.74
per MW	4.70	6.35
Total	211.28	4,792.34

System Total	5,003.62 MWh

This number represents a small portion of the overall losses on the entire power system. In Ireland as of 2013 the overall losses on the transmission and distribution system came to 2.023 TWh. Calculating in percentage terms the expected decrease in losses with the system wide adaptation of the novel technology for PV, a value of 0.25% can be achieved.

One point to consider here is that the observed reduction in energy losses is limited to the simulated networks. The benefits of a reduction in current flow in a radial connection are carried throughout the series connections, further energy losses are likely to have occurred in the connecting network each representative networks are supplied from. Without simulating the entire power system these further benefits of the technology cannot be accurately estimated. The final numbers reported here are therefore conservative estimates.

Conclusion

Modelling the changing environment of a power system the representative networks are host to solar generation, varying demand and changing transformer tap settings for a given year. Monitoring the local measurements at the PV point of connection, the active loss reducing technology calculates an optimal set point in each hour to reduce the congestion of external lines and in turn, reducing energy loss.

At any given time in every representative network the losses found in the base case were greater than those found with use of the set points found by the loss reducing technology. This saving though dependant on connection type is improved in all representative networks. Scaling these models to the wider system the impact on the entire power system is an annual reduction of 5 GWh.

Work Package 2 – Economic Analysis

Introduction

In 2015 a study was carried out to investigate the economic benefits of wide scale deployment of NovoGrid's Smart Grid Automation System (AVA) across the wind power fleet. AVA is a low-cost intelligent control solution that harnesses the untapped capability of generators connected to the grid via power electronic inverters and to reduce losses on the electrical network. It achieves this by optimising the output of the generator's inverters in real-time to best suit the prevailing conditions on the electrical network.

Recently, Solar PV technology has attracted considerable interest in Ireland. A second phase of this study has been sponsored by SEAI to evaluate the potential benefits of AVA when applied to Solar PV generation. Thus, the objective of the present study is to quantify the benefits of the loss reduction in a system setting in terms of reductions to emissions, system marginal price and production costs. As in Phase 1, the Epiphron production cost modelling tool has been used to model the economic impact of wide-scale adoption of AVA for new PV capacity on the Irish grid. This involves simulating the operation of the Irish power system on an hourly basis for a full year. Conventional and renewable generator operating regimes are simulated so that customer electricity demand is met at lowest cost while simultaneously ensuring that system operational constraints such as reserve and stability constraints are satisfied. This allows the costs of operating the system to be estimated and the impact of AVA on these costs to be quantified.

Methodology

A production cost model was used to estimate the potential benefit of AVA in an integrated system setting taking into account customer demand, generating resources, technical and operational constraints and fuel prices. The hourly scheduling of generators is simulated such that demand is met at lowest cost subject to satisfying system operating constraints as defined by EirGrid. This analysis yields the total operating costs of electricity production along with emissions volumes and the marginal cost of electricity production. PV and Wind energy curtailment is also quantified.

The Epiphron Modelling Tool

The Epiphron modelling tool is a stochastic production cost modelling tool co-developed at the Electricity Research Centre with Energy Reform Ltd. This tool is a development and enhancement of the Wilmar modelling tool which has seen widespread use across many universities and in industry during the past number of years and was the basis of Workstream 2b of the All Island Grid study. The Epiphron tool features an enhanced stochastic model and features N-1 security constrained unit commitment and dispatch. It also features a SEM uplift model for forecasting calculating SEM prices.

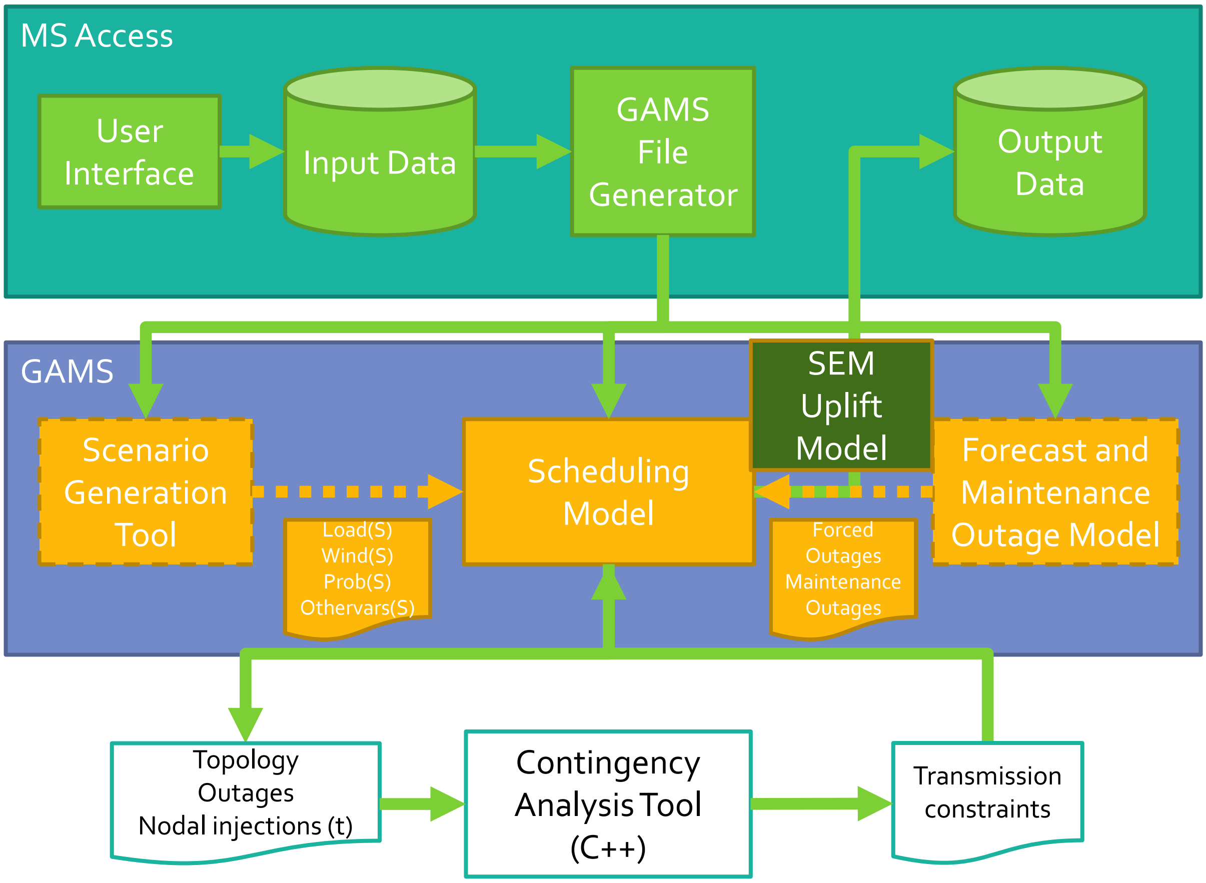


FIGURE 10 – THE EPIPHRON PRODUCTION COST MODELLING TOOL

The main components of the tool are illustrated in the figure above. The tool is comprised of an Access user interface through which all data manipulations are performed. The core optimisation models are implemented in GAMS while the DC load flow and N-1 contingency analysis functionality is implemented in C++.

The tool has been extensively validated against other tools and studies, including replication of EirGrid's constraint report results.

Capturing the Impact of AVA

For this project the Epiphron tool was used in deterministic mode and was run at hourly resolution. To capture the benefit of AVA when applied to Solar PV plants, the technical work package calculated the benefit of a typical utility scale PV installation. This was scaled up to a capacity of 800MW. An hourly time series of PV MW production was used to estimate the system level benefit of AVA in terms of avoided MW losses for each hour of a typical year. The resulting normalised benefit as a function of normalised instantaneous PV power production is shown in the figure below.

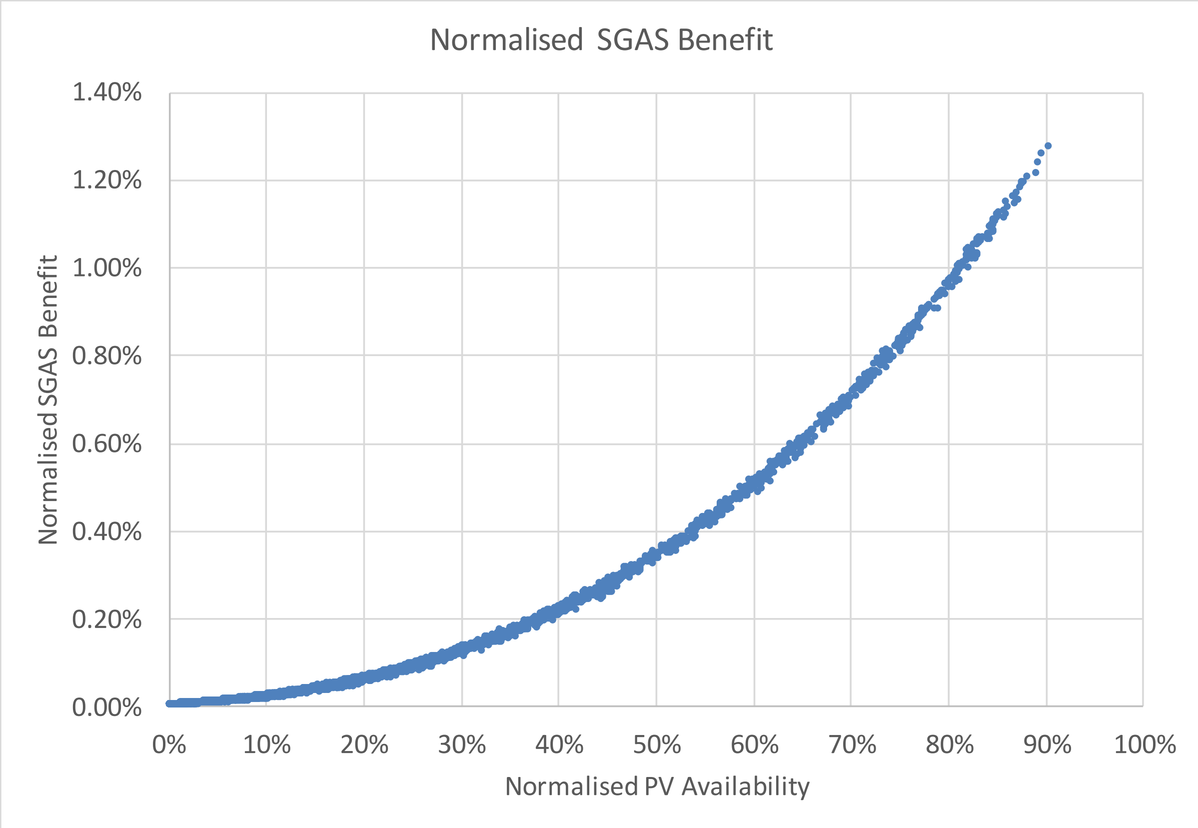


FIGURE 11 –BENEFIT OF AVA AS A FUNCTION OF NORMALISED AVAILABLE PV PRODUCTION.

It can be seen that the impact is non-linear and the relative benefit is high at higher levels of available PV power production.

The objective of this work package was to quantify the production costs benefits of the losses avoided by AVA. To do this, the production cost model was run with a time series representing available PV production in the study year (2020). The model was run again with a second time series which represented the available PV production if AVA was installed on all PV installations across the system, assuming state of the ar.

Summary of Production Cost Modelling Assumptions

As in Phase 1, the production cost modelling exercise was carried out using an operationally focussed production cost model to determine the actual realised PV and wind power production and system costs with and without the simulated impact of AVA. The assumptions have been updated with the latest available published date from EirGrid for the year 2020. A detailed list of assumptions can be found below in Section 5. A summary of the assumptions and data used in the model is shown in the table below:

TABLE 5 PRODUCTION COST MODELLING DATA SOURCES

Data	Source(s)
Forecasted load peak and total energy consumption	Latest EirGrid Generation Capacity Statement (2016-2025)
Conventional generation portfolio	Latest EirGrid Generation Capacity Statement (2016-2025)
Generation commercial and technical data	• All Island Project Plexos model for existing plant • New generation characteristics based on similar existing technology and vintage and published data
Fuel prices	UK Department of Energy Forecasts (November 2015)
Operational constraints	EirGrid Operational Constraints publication
System Non-Synchronous Penetration (SNSP) limit	75%

The production time series data characterises the available energy from each PV plant in the production cost model. The production cost model simulates unit commitment and the hourly dispatch of the power system for a year, optimising generation resources against forecasted electricity demand and satisfying a number of operational constraints such as:

- Reserve (spinning, replacement etc.)
- Minimum conventional units online constraint
- System Non-Synchronous Penetration Level (SNSP)
- Unit technical constraints (minimum up/down times, ramp rates, minimum stable generation etc.)

It does not include any assumptions regarding transmission constraints. The output of this model is the actual production of wind, PV and conventional generation resources. Since variable renewable resources including wind and PV are modelled with zero incremental cost (that is, wind or PV have no fuel costs associated with them), the model seeks to maximise production from these resources subject to the constraints outlined above. The total realized production of PV and wind power may be less than the available production due to curtailment, arising chiefly due to the SNSP constraint. The model also outputs total system operating costs and emissions.

Results

To estimate the benefit of AVA, the production cost model was run for the year 2020. The model was run twice, once with the simulated impact of the technology and once without. The resulting differences are reported below.

Production Cost Modelling Results

The results in system level production cost metrics arising from the simulation of AVA are reported below. The direct impact of AVA installation on 800MW of PV capacity is an increase of between 0.63% in realised PV production. This translates into a production cost saving of €286,000 or around 0.02%. CO_2 Emissions benefits are of the same order of magnitude with a benefit of between 0.01%.

TABLE 6 PRODUCTION COST BENEFITS FOR CASE A

Quantity	Units	Base Case	With AVA	Absolute Benefit	Pct Benefit
CO2 Emissions	kTons	16178	16176	1.6	0.01%
NOX Emissions	kTons	536	536	0.2	0.04%
S02 Emissions	kTons	61	61	0.0	-0.01%
Total Generation Costs	€ millions	1466	1465	0.3	0.02%
Available PV	GWh	788.7	793.7	5.0	0.63%
Realised PV	GWh	778.2	783.1	4.9	0.63%
PV Curtailment	GWh	10.5	10.6	0.1	0.92%
PV Curtailment %	%	1.3%	1.3%		
Available Wind	GWh	11410	11410		
Realised Wind	GWh	10875	10874		
Wind Curtailment	GWh	535	536		
Wind Curtailment %	%	4.7%	4.7%		

Conclusions

Some conclusions and recommendations arising from this study are presented below.

- In the year studied, results suggest that AVA has the potential to increase PV production by 0.63%. The study suggests that this increase has a potential value of €286,000 in terms of production cost savings.
- AVA has the potential to reduce CO_2 emissions on the island of Ireland by 1.6 kTons.

Work Package 3 – Financial Analysis

Introduction

Method

An Excel financial model of a PV solar generator was built. The inputs to the financial model were aligned to the assumptions made in WP1 e.g. capacity factor used was 11.2%.

As no utility-scale PV solar generator has yet been constructed in Ireland the majority of cost assumptions were based on UK sources. The cost assumptions were sense-checked with a range of Irish PV solar developers.

The MWh impact of AVA was inserted into the financial model via an increase to the Distribution Loss Adjustment Factor (DLAF). While the existing Irish DLAF mechanism would not yet reflect the impact of AVA, for the purposes of this report it is assumed that it would in a similar fashion to the UK Line Loss Factor methodology.

PV solar generator projects are financially evaluated using the Internal Rate of Return (IRR) method. A target IRR or hurdle rate is selected by the investor in advance and a project only receives investment if it is expected to clear the predetermined hurdle rate. PV Solar projects typically have a hurdle rate of 7%[7].

Reference Scenario

A reference scenario was run using the financial model without the impact of the additional MWh added by AVA. The objective was to identify the price per MWh the project would need to receive in order to return an IRR of 7%.

TABLE 7: SUMMARY OF REFERENCE SCENARIO ASSUMPTIONS

Installed Capacity (MW)	5
Capacity Factor	11.2%
Distribution Loss Adjustment Factor	1.000
Total CapEX	€4,900,000
Support Structure	Increase with Inflation
IRR Hurdle Rate	**7.00%**

[7] Note on Leveraging: While debt was built into the financial model, it was decided to run the scenario comparisons on an unleveraged basis. Different project developers will have access to a wide range of debt and equity instruments that would overly complicate the analysis. Thus the 7% IRR hurdle rate is an unleveraged IRR. Leveraged IRRs and their associated Debt Service Coverage Ratios (DSCR) where they are included are for noting and potential future analysis and discussion beyond the scope of this report.

The previous Irish support scheme for renewable generators, REFIT, had a support duration of 15 years. The IRR of the reference scenario was analysed for support schemes lasting from 10 to 25 years.

TABLE 8: ANALYSIS OF SUPPORT PRICE REQUIRED VS DURATION OF SUPPORT TO ACHIEVE IRR HURDLE RATE (REFERENCE SCENARIO)

Support Price per MWh	Support Duration (Years)															
	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
€106	2.2%	2.7%	3.1%	3.5%	3.9%	4.3%	4.7%	5.0%	5.3%	5.6%	5.9%	6.1%	6.4%	6.6%	6.7%	6.9%
€108	2.5%	2.9%	3.3%	3.8%	4.2%	4.6%	4.9%	5.3%	5.6%	5.9%	6.2%	6.4%	6.6%	6.8%	7.0%	7.2%
€110	2.7%	3.1%	3.6%	4.0%	4.5%	4.9%	5.2%	5.6%	5.9%	6.2%	6.5%	6.7%	6.9%	7.1%	7.3%	7.5%
€112	2.9%	3.4%	3.9%	4.3%	4.7%	5.1%	5.5%	5.9%	6.2%	6.5%	6.7%	7.0%	7.2%	7.4%	7.6%	7.7%
€114	3.1%	3.6%	4.1%	4.6%	5.0%	5.4%	5.8%	6.1%	6.5%	6.8%	7.0%	7.3%	7.5%	7.7%	7.8%	8.0%
€116	3.3%	3.9%	4.4%	4.8%	5.3%	5.7%	6.1%	6.4%	6.7%	7.0%	7.3%	7.5%	7.7%	7.9%	8.1%	8.3%
€118	3.6%	4.1%	4.6%	5.1%	5.6%	6.0%	6.3%	6.7%	7.0%	7.3%	7.6%	7.8%	8.0%	8.2%	8.4%	8.5%
€120	3.8%	4.3%	4.9%	5.4%	5.8%	6.2%	6.6%	7.0%	7.3%	7.6%	7.8%	8.1%	8.3%	8.5%	8.6%	8.8%
€122	4.0%	4.6%	5.1%	5.6%	6.1%	6.5%	6.9%	7.3%	7.6%	7.9%	8.1%	8.3%	8.5%	8.7%	8.9%	9.0%
€124	4.3%	4.8%	5.4%	5.9%	6.4%	6.8%	7.2%	7.5%	7.8%	8.1%	8.4%	8.6%	8.8%	9.0%	9.1%	9.3%
€125	4.4%	4.9%	5.5%	6.0%	6.5%	6.9%	7.3%	7.7%	8.0%	8.3%	8.5%	8.7%	8.9%	9.1%	9.3%	9.4%
€126	4.5%	5.1%	5.6%	6.2%	6.6%	7.1%	7.4%	7.8%	8.1%	8.4%	8.6%	8.9%	9.1%	9.2%	9.4%	9.5%
€130	5.0%	5.6%	6.1%	6.7%	7.2%	7.6%	8.0%	8.3%	8.6%	8.9%	9.2%	9.4%	9.6%	9.7%	9.9%	10.0%
€132	5.2%	5.8%	6.4%	6.9%	7.4%	7.9%	8.2%	8.6%	8.9%	9.2%	9.4%	9.6%	9.8%	10.0%	10.1%	10.3%
€134	5.4%	6.1%	6.7%	7.2%	7.7%	8.1%	8.5%	8.9%	9.2%	9.4%	9.7%	9.9%	10.1%	10.2%	10.4%	10.5%
€136	5.7%	6.3%	6.9%	7.5%	8.0%	8.4%	8.8%	9.1%	9.4%	9.7%	9.9%	10.1%	10.3%	10.5%	10.6%	10.8%
€138	5.9%	6.6%	7.2%	7.7%	8.2%	8.6%	9.0%	9.4%	9.7%	9.9%	10.2%	10.4%	10.6%	10.7%	10.9%	11.0%
€140	6.1%	6.8%	7.4%	8.0%	8.5%	8.9%	9.3%	9.6%	9.9%	10.2%	10.4%	10.6%	10.8%	11.0%	11.1%	11.2%
€142	6.4%	7.0%	7.7%	8.2%	8.7%	9.2%	9.5%	9.9%	10.2%	10.5%	10.7%	10.9%	11.1%	11.2%	11.3%	11.5%
€144	6.6%	7.3%	7.9%	8.5%	9.0%	9.4%	9.8%	10.1%	10.4%	10.7%	10.9%	11.1%	11.3%	11.5%	11.6%	11.7%
€146	6.9%	7.5%	8.2%	8.8%	9.3%	9.7%	10.1%	10.4%	10.7%	11.0%	11.2%	11.4%	11.5%	11.7%	11.8%	11.9%
€148	7.1%	7.8%	8.4%	9.0%	9.5%	9.9%	10.3%	10.7%	10.9%	11.2%	11.4%	11.6%	11.8%	11.9%	12.1%	12.2%

The key result is that a support price of €126/MWh or 12.6c/kWh would be required for the reference scenario project to clear the IRR hurdle rate of 7% under a 15-year support scheme

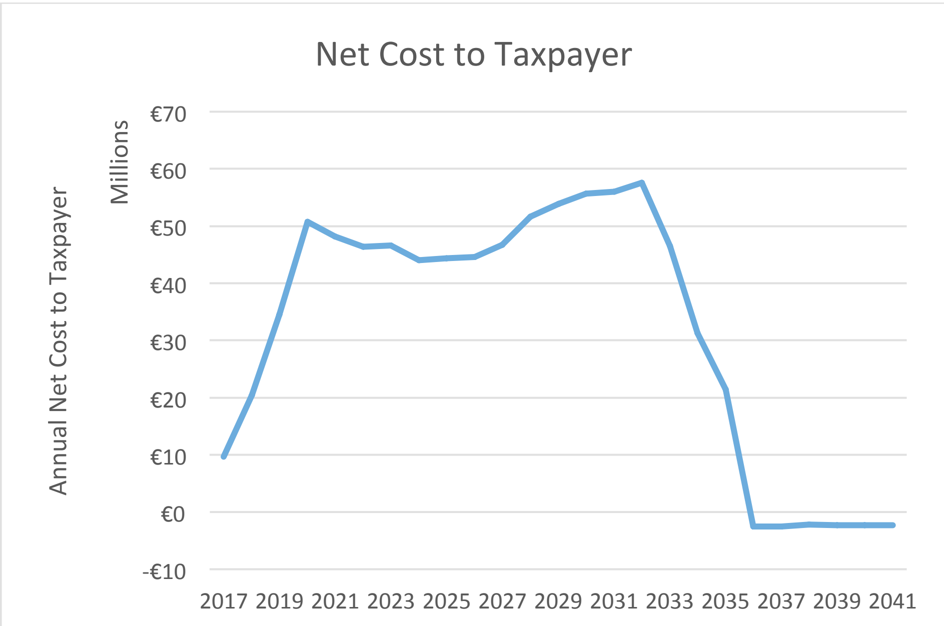
The cost to the taxpayer was calculated as the difference between the support revenue and the market revenue less the corporation tax paid by the project.

Over an expected 25 year life of the reference scenario the net present value[8] cost to the taxpayer would be €3.9 million.

Support Received	€3,974,315
Tax Paid	-€173,954
NPV of Cost to Taxpayer	**€3,800,360**

The financial model was scaled to an expected PV solar installed capacity of 800 MW by 2020 and then run out to 2041 i.e. 2017 start year + 25 operating years. The CapEx cost per MW was reduced year-on-year by 4% and the support price per MWh adjusted to reflect this.

Year	2017	2018	2019	2020	…	2041
Subsidised MW	150	300	500	800	…	800
Support Cost	€9,665,994	€20,440,858	€34,491,470	€50,757,939	…	€0
Tax Paid	€0	€0	€0	€0	…	€2,297,268
Net Cost to Taxpayer	**€9,665,994**	**€20,440,858**	**€34,491,470**	**€50,757,939**	…	**(€2,297,268)**



The NPV cost to the taxpayer of the reference scenario is €530,556,198.

[8] The National Development Finance Agency Discount Rate of 4.02% for projects exceeding 10 years was used in the NPV calculations

Support Schemes

The three most common support schemes for renewable generation are:

1) Feed-In-Tariff (FIT) / Feed-In-Premium (FIP)
2) Auction Mechanism
3) Investment Tax Credits (ITC)

Feed-In-Tariff / Feed-In-Premium

Ireland has decades of successful experience with FITs, although technically the REFIT scheme was a FIP, whereby the generator is paid a top-up premium to the market price for a fixed number of years.

This has the effect of providing all generators of a particular technology with a fixed price per MWh.

FIT/FIPs provide certainty to generators and investors but place a heavy burden upon the administrators of the scheme to identify and select the correct price.

Select a FIT/FIP to low, investors will not invest and the country will not achieve its renewable energy targets. Select a FIT/FIP to high and the cost to the taxpayer would be excessive.

Auction Mechanism

In auctions the price received by the generators is decided in a public bidding process prior to the construction of the generator.

Typically the auction administrators decide upon a fixed quantity of generation capacity for the auction e.g. 500 MW. The auction may or may not be technology specific. Generators submit closed bids to the auction administrators before a closing date. The bids are opened by the auction administrators, ranked in order of price from low to high. The lowest bids are selected until the capacity is fulfilled.

Winning bidders receive their bid price for a fixed number of years.

The advantage of the auction mechanism is that the market conducts the price discovery and not the administrators, therefore it should provide the most cost-effective outcome for the taxpayer. The administration of the auction can be complicated. This was recently demonstrated by the UKs suspension of their Contract-for-Difference auctions in 2015 following issues surrounding the bidding process on behalf of some generators.

Investment Tax Credits

ITCs allow a company that develops or finances a renewable generator to deduct a percentage of the capital cost of the generator against their tax bill.

In the US, the Section 48 ITC has been enormously successful in promoting the deployment of solar generation. The US ITC allows companies to deduct 30% of the cost of deploying the generator. This is due to reduce to 26% in 2020, 22% in 2021 and 10% permanently thereafter.

The advantage of ITCs is that they are stable and transparent. Developers and financiers can plan in confidence of the support available, which reduces the cost of funding the project.

The disadvantages, particularly in the US context, emanate from how the tax credit is claimed. If a company has an insufficient tax liability to claim the full amount of the credit it may have to let the value lapse or alternatively enter into a tax equity arrangement with a partner. A tax equity arrangement involves a costly and complex transaction whereby the tax equity partner who has a sufficiently large tax liability receives most of the value of the ITC. This results in the concentration of the taxpayer funded support scheme in a few large companies.

Prevalence of Different Support Schemes

FIT/FIPs remain the most popular support scheme globally[9]. They are popular in countries with immature renewable energy markets due to the certainty they provide investors. As a country's renewable energy market matures, auctions become more prevalent as the administrators focus moves from encouraging initial growth to value for money for the taxpayer.

As more countries become comfortable with the detail of auction mechanisms they are rapidly becoming the preferred support scheme. The UK for example has phased out FIT/FIPs entirely for utility-scale renewable generators in favour of an auction mechanism.

ITCs are also popular as precedence often exists within a country's tax laws for other industries e.g. film production, manufacturing etc.

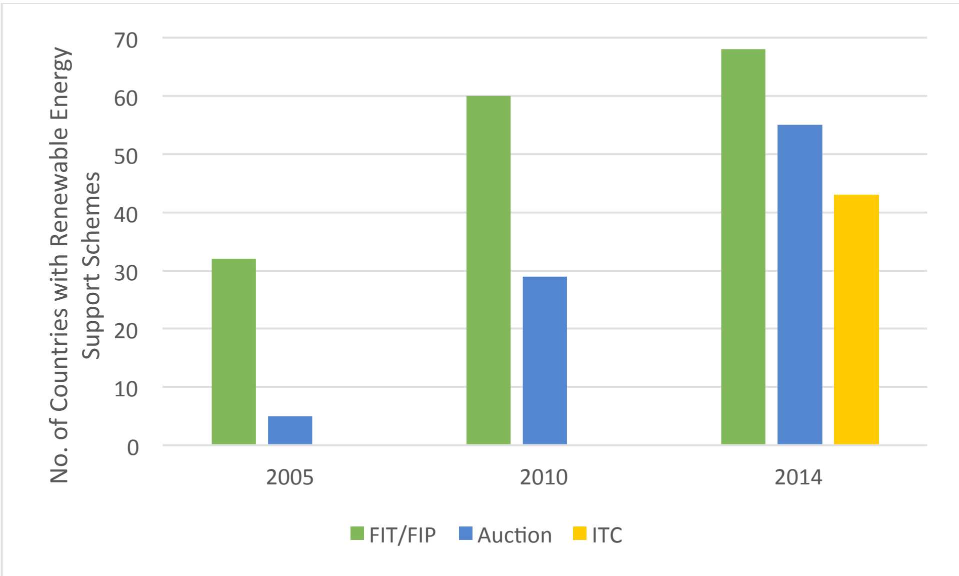


FIGURE 12: GLOBAL PREVALENCE OF RENEWABLE ENERGY SUPPORT SCHEMES

FIGURE 13: COUNTRIES THAT HAVE IMPLEMENTED RENEWABLE ENERGY AUCTIONS BY 2015

AVA Scenario

Taking the results from WP1, the Type D 5 MW PV Solar generator experienced an increase in power output of 31.74 MWh/year.

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9 KPMG – Taxes & Incentives for Renewable Energy Report 2015

For the 11.2% reference scenario site this equates to a 0.6% increase in power output.

This was reflected in the financial model as an increase to the Distribution Loss Adjustment Factor (DLAF) from 1.000 to 1.006.

While the existing Irish DLAF mechanism would not yet reflect the impact of AVA, for the purposes of this report it is assumed that it would in a similar fashion to the UK Line Loss Factor methodology.

Installed Capacity (MW)	5
Capacity Factor	11.2%
Distribution Loss Adjustment Factor	1.006
Total CapEX	€4,900,000
Support Structure	Increase with Inflation
IRR Hurdle Rate	7.00%

The impact on the PV solar generator’s income statement is an EBIT increase of over €81,000.

P&L	AVA Scenario	Reference Scenario	Difference
Revenue	€13,880,039	€13,797,256	€82,784
OpEX	€4,852,594	€4,851,352	€1,242
EBIT	€9,027,445	€8,945,904	€81,542

Maintaining the FIT/FIP support structure at €126/MWh over 15 years, would yield an increased IRR of 7.2% to the generator owner (Highlighted in dark green in Table 7).

The impact on the cost of the support scheme would be negligible.

	Reference Scenario	AVA Scenario	Difference
Support Received	€3,974,315	€3,974,315	€0
Tax Paid	-€173,954	-€179,642	€5,688
NPV of Cost to Taxpayer	€3,800,360	€3,794,673	€5,688

This demonstrates the inflexibility of FIT/FIPs to incorporate future technology innovations as a continuous reappraisal of the FIT/FIP by the administrators to reduce the FIT/FIP price per MWh would negate its key advantage i.e. stability and investor certainty.

TABLE 9: ANALYSIS OF SUPPORT PRICE REQUIRED VS DURATION OF SUPPORT TO ACHIEVE IRR HURDLE RATE (AVA SCENARIO)

	Support Duration (Years)															
Support Price per MWh	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
€104	2.1%	2.5%	3.0%	3.4%	3.8%	4.1%	4.5%	4.8%	5.1%	5.4%	5.7%	6.0%	6.2%	6.4%	6.6%	6.7%
€106	2.4%	2.8%	3.2%	3.6%	4.0%	4.4%	4.8%	5.1%	5.4%	5.7%	6.0%	6.2%	6.5%	6.7%	6.8%	7.0%
€108	2.6%	3.0%	3.5%	3.9%	4.3%	4.7%	5.1%	5.4%	5.7%	6.0%	6.3%	6.5%	6.7%	6.9%	7.1%	7.3%
€110	2.8%	3.3%	3.7%	4.2%	4.6%	5.0%	5.3%	5.7%	6.0%	6.3%	6.6%	6.8%	7.0%	7.2%	7.4%	7.5%
€112	3.0%	3.5%	4.0%	4.4%	4.9%	5.3%	5.6%	6.0%	6.3%	6.6%	6.8%	7.1%	7.3%	7.5%	7.7%	7.8%
€114	3.2%	3.7%	4.2%	4.7%	5.1%	5.5%	5.9%	6.3%	6.6%	6.9%	7.1%	7.4%	7.6%	7.8%	7.9%	8.1%
€116	3.5%	4.0%	4.5%	5.0%	5.4%	5.8%	6.2%	6.5%	6.8%	7.1%	7.4%	7.6%	7.8%	8.0%	8.2%	8.3%
€118	3.7%	4.2%	4.7%	5.2%	5.7%	6.1%	6.5%	6.8%	7.1%	7.4%	7.7%	7.9%	8.1%	8.3%	8.5%	8.6%
€120	3.9%	4.5%	5.0%	5.5%	5.9%	6.4%	6.7%	7.1%	7.4%	7.7%	7.9%	8.2%	8.4%	8.6%	8.7%	8.9%
€122	4.2%	4.7%	5.2%	5.8%	6.2%	6.6%	7.0%	7.4%	7.7%	8.0%	8.2%	8.4%	8.6%	8.8%	9.0%	9.1%
€124	4.4%	5.0%	5.5%	6.0%	6.5%	6.9%	7.3%	7.6%	7.9%	8.2%	8.5%	8.7%	8.9%	9.1%	9.2%	9.4%
€125	4.5%	5.1%	5.6%	6.1%	6.6%	7.0%	7.4%	7.8%	8.1%	8.4%	8.6%	8.8%	9.0%	9.2%	9.4%	9.5%
€126	4.6%	5.2%	5.8%	6.3%	6.7%	7.2%	7.6%	7.9%	8.2%	8.5%	8.7%	9.0%	9.2%	9.3%	9.5%	9.6%
€130	5.1%	5.7%	6.3%	6.8%	7.3%	7.7%	8.1%	8.4%	8.7%	9.0%	9.3%	9.5%	9.7%	9.8%	10.0%	10.1%
€132	5.3%	5.9%	6.5%	7.1%	7.5%	8.0%	8.4%	8.7%	9.0%	9.3%	9.5%	9.7%	9.9%	10.1%	10.2%	10.4%
€134	5.6%	6.2%	6.8%	7.3%	7.8%	8.2%	8.6%	9.0%	9.3%	9.5%	9.8%	10.0%	10.2%	10.3%	10.5%	10.6%
€136	5.8%	6.4%	7.0%	7.6%	8.1%	8.5%	8.9%	9.2%	9.5%	9.8%	10.0%	10.2%	10.4%	10.6%	10.7%	10.9%
€138	6.0%	6.7%	7.3%	7.8%	8.3%	8.8%	9.1%	9.5%	9.8%	10.1%	10.3%	10.5%	10.7%	10.8%	11.0%	11.1%
€140	6.3%	6.9%	7.6%	8.1%	8.6%	9.0%	9.4%	9.8%	10.0%	10.3%	10.5%	10.7%	10.9%	11.1%	11.2%	11.3%
€142	6.5%	7.2%	7.8%	8.4%	8.9%	9.3%	9.7%	10.0%	10.3%	10.6%	10.8%	11.0%	11.2%	11.3%	11.5%	11.6%
€144	6.7%	7.4%	8.1%	8.6%	9.1%	9.5%	9.9%	10.3%	10.5%	10.8%	11.0%	11.2%	11.4%	11.6%	11.7%	11.8%
€146	7.0%	7.7%	8.3%	8.9%	9.4%	9.8%	10.2%	10.5%	10.8%	11.1%	11.3%	11.5%	11.7%	11.8%	11.9%	12.0%

Comparison of Net Cost to Taxpayer under FIT/FIP and Auction Support Schemes

Table 7 also reveals that when applying the benefits of AVA there was a material decrease in the support price per MWh required to achieve the IRR hurdle rate of 7%.

For the 15-year support example, the support price required was reduced to €125/MWh.

A difference of €1/MWh over 15 years compared to the reference scenario.

Under a FIT/FIP support mechanism this extra cash would be received by the generator. However, under an auction mechanism the generator owner would be incentivised to bid at the lowest possible price that achieves the IRR hurdle rate i.e. €125/MWh.

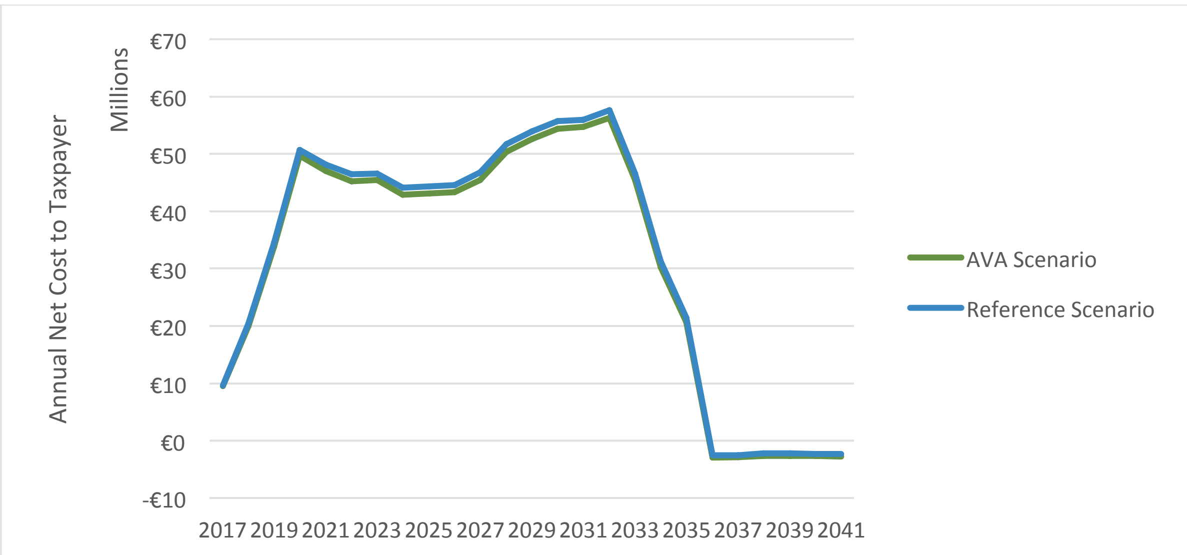
This would result in the taxpayer paying a lower support price to the generator and therefore reducing the cost of the support.

Support Price Paid	€126 /MWh	€125 / MWh	Difference
Support Received	€3,974,315	€3,914,042	€60,273
Tax Paid	-€179,642	-€173,580	-€6,062
NPV of Cost to Taxpayer	€3,794,673	€3,740,461	€54,211

Scaling up to 800 MW by 2020 the NPV cost to the taxpayer of the AVA Scenario is €516,214,131 versus €530,556,198 in the Reference Scenario.

The reduction in the cost of the support scheme using an auction mechanism would be €14.3 million.

Year	2017	2018	2019	2020	...	2041
Subsidised MW	150	300	500	800	...	800
Support Cost	€9,518,826	€20,144,167	€33,993,406	€49,956,755	...	€0
Tax Paid	€0	€0	€0	€0	...	€2,338,059
Net Cost to Taxpayer	€9,465,563	€20,045,836	€33,836,349	€49,689,075	...	-€2,713,336



Investment Tax Credits

The existing and highly successful US ITC has already been described. In Ireland there currently exists a similarly successful ITC scheme for Film and Television.

The rules surrounding Section 481 of the Taxes Consolidation Act[10] were updated in the 2015 budget and could provide the legislative basis for a future Irish PV Solar ITC.

Summary of Existing Irish Film & TV ITC

From January 1st 2015, Ireland's tax incentive "Section 481" for film and television is enhanced, creating a new payable tax credit programme.

- Increased rate of relief
    - The rate of tax relief has been significantly increased and is now worth up to 32% of eligible Irish expenditure.
- Expansion of eligible expenditure criteria
    - The payable tax credit is now based on the cost of ALL cast & crew working in Ireland, regardless of nationality.
- Greater flexibility in the application process
    - An application for a certificate entitling the applicant to the tax credit can be submitted at any time prior to the completion of the project.

What types of projects qualify?

The incentive applies to feature film, TV drama (singles or series), animation (excluding computer games), & creative documentary. Projects must either pass the Cultural Test or qualify as an official co-production under one of Irelands Bilateral Co-Production Treaties or the European Convention on Cinematographic Co-Production.

Who is eligible to apply?

The application to Revenue is made by the "Producer Company".

A "Producer Company" must:

- Be Irish resident or trading through a branch or agency
- Make film and TV for cinema exhibition or broadcast or online
- Be trading for at least 12 months and have filed with Revenue a corporation tax return
- Not be connected to a broadcaster
- Hold 100% shareholding in a "Qualifying Company"

A "Qualifying Company" must:

- Be Irish resident or trading through a Branch or Agency
- Exists as an SPV to make one film

What is the "Section 481" benefit worth?

The applicant producer company can claim a payable tax credit of up to 32% of "eligible expenditure".

What is eligible expenditure?

The payable tax credit is based on the cost of ALL cast & crew working in Ireland, regardless of nationality, as well as goods, services & facilities purchased in Ireland.

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[10] Section 481 of the TCA http://www.irishstatutebook.ie/eli/1997/act/39/section/481/enacted/en/html

Is there a cap on the incentive?

There is no annual cap or limit on the funding of the programme, meaning there is no limit to the value of the cumulative payable tax credits made by Revenue.

The tax credit has a "per project" cap of up to 32% of the lower of:

1. "Eligible expenditure"
2. 80% of the total cost of production
3. €50 million

How is payment made by Revenue?

Payment of the relief may be claimed against the producer company's corporation tax (CT) liabilities. In the event the relief due is greater than any tax due by the producer company, then a payment of the excess will be made by Revenue.

Is there a minimum spend level?

Projects are excluded from the incentive if their "eligible expenditure" is less than €125,000, or the total cost of production is less than €250,000.

Is there a "sunset" date?

Ireland's film and TV tax credit of up to 32% runs until December 31st 2020.

Providing a Basis for an Irish PV Solar ITC

There would have to be some adaptations most notably what qualifies as “eligible expenditure”. It would be critical to a PV Solar ITC that the capital costs of the panels, inverters etc. would be included.

The primary advantage over the US ITC would be the higher rate of 32% compared to 30%.

The other main advantage is that Revenue repay the tax credit as a cash payment to the production company even if it doesn’t have a sufficient tax liability to absorb the full amount. This avoids the costly and complex tax equity arrangements that exist in the US.

Ireland’s low corporation tax rate of 12.5% would make tax equity arrangements unattractive to the vast majority of companies.

Modelling Assumptions of Irish PV Solar ITC

It was assumed that all capital expenditure on the PV Solar project described in the Reference Scenario was considered "eligible expenditure" and an ITC rate of 32% was applied.

	per MW	Total
Engineering Procurement & Construction	€900,000	€4,500,000
Grid Connection Costs	€80,000	€400,000
Total CapEX		**€4,900,000**
Investment Tax Credit @ 32%		€1,568,000
Net CapEX		**€3,332,000**

Even with this ITC the PV Solar project would require additional support to achieve the IRR hurdle rate of 7%. Table 8 identifies a support price per MWh of €94 or 9.4c/kWh.

It should be noted that the approximate current market price is €60/MWh and the current REFIT for large-scale wind price is €80/MWh (incl. balancing payments).

The net cost reduction for the taxpayer of this ITC and support price at €336,000 per project is significant.

	FIT/FIP @ €126/MWh	ITC @ €94/MWh	Difference
Investment Tax Credit	€0	€1,568,000	-€1,568,000
Subsidy Revenue	€3,974,315	€2,045,574	€1,928,741
Tax Paid	-€179,642	-€135,663	-€43,979
Net Cost to Taxpayer	**€3,794,673**	**€3,477,911**	**€316,762**

Scaling up to 800 MW by 2020 the NPV cost to the taxpayer of the ITC support scheme is €361,484,352. A reduction of €169 million compared to the FIT/FIP reference scenario.

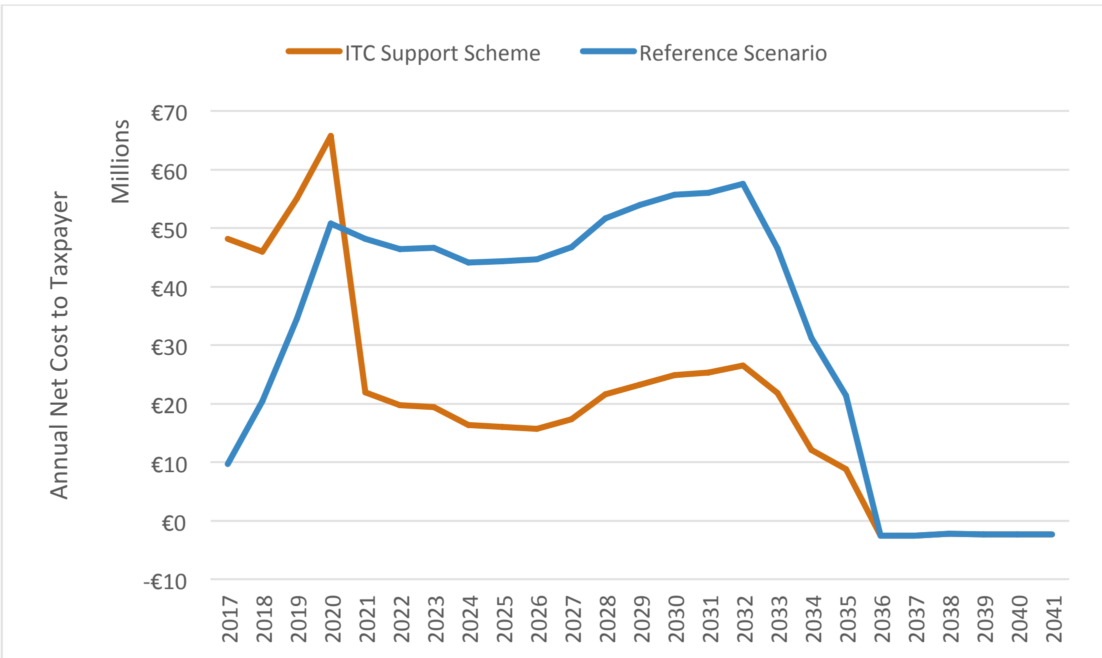

TABLE 10: ANALYSIS OF SUPPORT PRICE REQUIRED VS DURATION OF SUPPORT TO ACHIEVE IRR HURDLE RATE (ITC REFERENCE SCENARIO)

Support Price per MWh	Support Duration (Years)															
	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
€60	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.7%	0.8%	0.8%	1.0%	1.1%	1.2%	1.4%	1.5%	1.6%	1.7%
€70	2.0%	2.0%	2.1%	2.3%	2.4%	2.6%	2.7%	2.9%	3.1%	3.3%	3.5%	3.7%	3.8%	4.0%	4.1%	4.3%
€80	3.4%	3.6%	3.8%	4.0%	4.3%	4.5%	4.7%	5.0%	5.2%	5.4%	5.6%	5.8%	6.0%	6.2%	6.3%	6.5%
€82	3.7%	3.9%	4.1%	4.4%	4.6%	4.9%	5.1%	5.4%	5.6%	5.8%	6.1%	6.3%	6.4%	6.6%	6.8%	6.9%
€84	4.0%	4.2%	4.5%	4.7%	5.0%	5.3%	5.5%	5.8%	6.0%	6.2%	6.5%	6.7%	6.9%	7.0%	7.2%	7.3%
€86	4.2%	4.5%	4.8%	5.1%	5.4%	5.6%	5.9%	6.2%	6.4%	6.7%	6.9%	7.1%	7.3%	7.4%	7.6%	7.7%
€88	4.5%	4.8%	5.1%	5.4%	5.7%	6.0%	6.3%	6.6%	6.8%	7.1%	7.3%	7.5%	7.7%	7.8%	8.0%	8.1%
€90	4.8%	5.1%	5.5%	5.8%	6.1%	6.4%	6.7%	7.0%	7.2%	7.4%	7.7%	7.9%	8.0%	8.2%	8.3%	8.5%
€92	5.1%	5.5%	5.8%	6.2%	6.5%	6.8%	7.1%	7.4%	7.6%	7.8%	8.1%	8.3%	8.4%	8.6%	8.7%	8.9%
€94	5.5%	5.8%	6.2%	6.5%	6.9%	7.2%	7.5%	7.7%	8.0%	8.2%	8.4%	8.6%	8.8%	9.0%	9.1%	9.2%
€96	5.8%	6.1%	6.5%	6.9%	7.2%	7.5%	7.8%	8.1%	8.4%	8.6%	8.8%	9.0%	9.2%	9.3%	9.5%	9.6%
€98	6.1%	6.5%	6.9%	7.2%	7.6%	7.9%	8.2%	8.5%	8.7%	9.0%	9.2%	9.4%	9.6%	9.7%	9.8%	10.0%
€100	6.4%	6.8%	7.2%	7.6%	8.0%	8.3%	8.6%	8.9%	9.1%	9.4%	9.6%	9.8%	9.9%	10.1%	10.2%	10.3%
€102	6.7%	7.1%	7.6%	8.0%	8.3%	8.7%	9.0%	9.3%	9.5%	9.7%	9.9%	10.1%	10.3%	10.4%	10.6%	10.7%
€104	7.0%	7.5%	7.9%	8.3%	8.7%	9.0%	9.3%	9.6%	9.9%	10.1%	10.3%	10.5%	10.7%	10.8%	10.9%	11.0%

Duration of Support Scheme & The Impact of Debt

Tables 6, 7 & 8 all agree that the longer the duration of the support scheme the lower the required support price per MWh.

Scenario	AVA		
Support Type	FIT	CfD	ITC + CfD
DLAF	1.006	1.006	1.006
ITC	0%	0%	32%
Support Duration (Years)	25	25	25
Unleveraged IRR	7.05%	7.00%	7.00%
Support Price	€107	€106	€82
Cost to Taxpayer – 25 Years	€4,213,692	€4,132,720	€3,624,112

However, a straight analysis shows that the overall cost to the taxpayer would be higher with a longer support duration.

Unless the impact of a longer duration on the cost of debt is considered in the analysis.

	15 Year Support	25 Year Support
Loan Term (Years)	15	21
Interest Rate	4.5%	3.5%
Debt : Equity Ratio	70%	81%
Support Duration (Years)	15	25
Support Price per MWh	€126	€101
Debt Service Coverage Ratio	1.45	1.27
Unleveraged IRR	7.06%	6.21%
Leveraged IRR	9.36%	10.38%
Net Cost to Taxpayer	**€3,800,360**	**€3,754,364**

A longer support duration would reduce the level of merchant risk. Projects would attract lower interest rates and support higher debt to equity ratios.

Under an auction mechanism this would enable developers to bid in lower prices per MWh, ultimately benefiting the taxpayer via a reduced support burden.

An additional impact of higher debt to equity ratios means that developers would have more equity capital to deploy and could potentially build more PV solar projects.

Conclusion & Recommendations

The analysis supports the use of an auction mechanism in the deployment of a support scheme for Irish PV Solar generation.

The advantages of an auction mechanism are:

- Shifts responsibility for price discovery from the state to project developers
- Enables support prices to adapt to novel, innovative technology
- Enables support prices to adapt to reduction in capital costs

Combining an auction mechanism with an investment tax credit, similar to the existing film production tax credit, would ultimately provide the best value for money to the taxpayer.

Appendices

Economic Analysis Assumptions

Data Sources

The following table lists some of the data sources used in this modelling exercise:

Data	Source(s)
Conventional generator portfolio	EirGrid Generation Capacity Statement 2016-2025
Conventional generator characteristics	• All Island Project website, published market model (Existing generation) • Previously published information (e.g. reserve capabilities) • New generation characteristics will be based on existing generation of similar type and vintage
Fuel prices	• UK Department of Energy and Climate Change fuel price forecasts • All Island Project fuel price calculator (adds transport costs etc. to commodity prices to yield delivered prices)
Transmission system	It is not intended to model the transmission system for this study – it is assumed the plant has firm transmission capacity rights.
Operation rules	• Operational Constraints update dated 05/02/2016 • EirGrid Area X Constraint report • EirGrid "DS3 Operational Capability Outlook" report May 2015 (SNSP)
Generator scheduled outages	Maintenance schedule generated which minimises expected load unserved based on historical outage durations
Forced outages	Semi-markov process implemented to simulate forced outages based on forced outage rate and mean time to repair (published). Model iterates to ensure simulated forced outage rate equals nominal rate
Demand	• System level demand peak and energy is based on EirGrid Generation Capacity Statement 2016-2026 • Demand time series are based on data received from EirGrid
Wind time series	• SEM-O Market Model Regional all island wind time series.
PV Time series	• Provided by NovoGrid

Demand Forecast

The median demand peak and energy figures from the EirGrid Generation Capacity Statement 2016-2025 will be used as follows:

TABLE 11. PEAK DEMAND ASSUMPTIONS

Year	Ireland (MW)	Northern Ireland (MW)	All Island (MW)
2020	5,196	1,767	6,919

TABLE 12. CONSUMPTION ASSUMPTIONS

Year	Ireland (GWh)	Northern Ireland (GWh)	All Island (GWh)
2020	30,681	9,255	39,935

PV Capacity

A PV capacity of 800MW has been assumed and is represented by a single 800MW plant and an hourly available production time series.

Wind Build Out

According to the 2016-2025 Generation Capacity Statement, the following are the installed wind levels for Ireland and Northern Ireland for 2020.

System Non-Synchronous Penetration Limit

In the published DS3 Operational Capability Outlook[11], published by EirGrid in May 2015, the SNSP is forecasted to reach 75% by 2020.

TABLE 13. ASSUMED SNSP LIMIT

Year	SNSP Limit
2020	75%

Interconnection

To simulate economic flows on the interconnectors with Great Britain, a methodology similar to the Regulator's Plexos model is used where a net generator is modelled on the UK side with a price duration curve. This will result in interconnector flows which are economically driven. Maximum interconnector flows for each interconnector are shown below. The EirGrid practice is to factor in a 20% de-rating of the interconnector to account for modelling and market imperfections. This de-rating has been included in the maximum flow limits below. One pole of the Moyle interconnector has been on a prolonged outage and is currently operating at half its capacity. However, according to the 2016-2025 Generation Capacity Statement, the interconnector is expected to be fully repaired by the end of 2016. The following limits take account of this.

TABLE 14. INTERCONNECTOR FLOWS

Direction	Flow Limit
Ireland – Wales	424 MW
Wales – Ireland	424 MW
Northern Ireland - Scotland	80 MW
Scotland - Northern Ireland	424 MW

[11] http://www.eirgrid.com/media/DS3_Programme_Operational_Capability_Outlook_2015.pdf

North-South Transfer Capacity and Second N-S Link

According to the latest Associated Transmission Reinforcements update published by EirGrid in February 2016[12], the second N-S link is expected to be in service by 2019. The present 2020 study will thus assume the second N-S interconnector is in service and that 2 units are required online in NI at all time. The following increased N-S flow limits will also apply

TABLE 15. N-S TRANSFER CAPACITY BEFORE SECOND N-S LINK IS COMPLETE IN 2018

Direction	Flow Limit Pre 2019	Flow Limit after 2019
Ireland - Northern Ireland	200MW	1000MW
Northern Ireland - Ireland	300MW	1000MW

Operational Constraints

As per EirGrid Operational Constraints update published in February 2016, the following operational constraints will be modelled:

TABLE 16. OPERATIONAL CONSTRAINTS INCLUDED IN THIS STUDY

Constraint	Description
Ireland Stability Constraint	At least 5 large units must be online in Ireland at any time
Northern Ireland Stability Constraint	At least 3 large units must be online in Northern Ireland until 2019 and 2 units after 2019
Dublin Generation	At least one of DB1, PBC, HNC, HN2 must be online at any time
Dublin North Generation	At least one of PBC, HNC, HN2 must be online at any time
Dublin South Generation	At least one of PBC, DB1 must be online at any time
Ireland Replacement Reserve	Combined output of OCGTs in Ireland is limited to 493MW
Northern Ireland Replacement Reserve	Combined output of OCGTs in Northern Ireland is limited to 211MW
Moneypoint	At least one of MP1, MP2, MP3 must be online at any time to support the 400kV network.

Operating Reserve

Operating reserve requirements have been used based on details contained in the EirGrid Area X Constraint report and the latest published operational constraints update. Before the second N-S interconnector, there is a minimum amount of spinning reserve which must be held in each jurisdiction. In the present study, since the second N-S interconnector is assumed to be in place, reserve is optimised on an all-island basis with no minimum requirements in Ireland or Northern Ireland.

TABLE 17. PRIMARY OPERATING RESERVE REQUIREMENTS BEFORE SECOND N-S LINK

	Base Requirement	Star	EWIC/MOYLE	Total
Day	333.75	-43	-150	140.75

[12] http://www.eirgridgroup.com/site-files/library/EirGrid/Q4-2015-ATR-Status-Update-as-at-31-Dec-15-published-01-Feb-16.pdf

Night	333.75	0	-150	183.75

TABLE 18. POR RESERVE REQUIREMENTS AFTER SECOND N-S LINK

	Base Requirement	Star	EWIC/MOYLE	Total
Day	333.75	-43	-150	140.75
Night	333.75	0	-150	183.75

Generation Outages

Generation maintenance outages will be scheduled using an outage scheduling tool which minimises expected load un-served over a year taking account of the risk of generator outages as defined by their forced outage rate and mean time to repair. The forced outage rate and mean time to repair values used are as published by the regulatory authorities and, for existing plant, are based on actual historical forced unavailability.

Transmission

As the plant is assumed to have firm transmission capacity, the transmission system is not modelled in detail in this study.

Market Mechanism

The market mechanism modelled in this study is a general mandatory pool where all players bid short run marginal costs into the market. An unconstrained run which omits reserve and stability constraints will yield market positions and the system marginal price while a constrained run will include all operational constraints and simulate actual real time dispatch. Differences between the two runs will yield individual unit constrained running.

Financial Analysis Reference Scenario

Assumptions

Revenue

Installed Capacity (MW)	5
Capacity Factor	11.2%
Capacity Factor Annual Degradation	0.4%
Energy Inflation	2.0%
General Inflation	2.0%
Distribution Loss Adjustment Factor	1.000

CapEX

	per MW	Total
Engineering Procurement & Construction	€900,000	€4,500,000
Grid Connection Costs	€80,000	€400,000
Total CapEX		**€4,900,000**
Investment Tax Credit		€0
Net CapEX		**€4,900,000**

Project Lifetime (Years)	25
Loan Term (Years)	15
Interest Rate	4.5%
Debt:Equity Ratio	70%
National Development Finance Agency Discount Rate	4.0%
Weighted Average Cost of Capital	5.4%
Capital Allowances (Years)	1
Tax Rate	12.5%
Depreciation (Years)	25
Debt Maintenance Reserve	50%

Investment Tax Credit (ITC)

ITC Cap	€70,000,000
ITC Cost Limit	100%
ITC Rate	0.0%

OpEX

O&M Costs (per MW)	€15,000
Rent per MW	€5,500
Insurance per MW	€2,000
Business Rates per MW	€5,000
Grid Fees (% of Gross Revenue)	1.5%
Miscellaneous Costs per MW	€1,500

Reference Scenario Income Statement

Total Revenue	€13,797,256
Total OpEX	€4,851,352

EBIT	**€8,945,904**
Interest	€1,360,705
Depreciation	€4,900,000
Tax	€335,650
N Profit	**€2,349,548**

Reference Scenario Balance Sheet

Balance Sheet	**End Year 1**	**End Year 25**
Fixed Assets		
Opening	€4,900,000	€196,000
Depreciation	€196,000	€196,000
Closing	**€4,704,000**	**€0**
Cash Balance	€144,454	€3,819,548
Net Assets	**€4,848,454**	**€3,819,548**
Loan	€3,264,970	€0
Investment Tax Credit	€0	€0
Total Net Assets	**€1,583,484**	**€3,819,548**
Financed By		
Shareholders	€1,470,000	€1,470,000
Retained Profit	€113,484	€2,349,548
	€1,583,484	**€3,819,548**

Reference Scenario Support Costs

		2017	2018	2019	2020	2041
Projected MW Deployment						
	2017	150	150	150	150	150
	2018		150	150	150	150
	2019			200	200	200
	2020				300	300
Total Subsidised MW		**150**	**300**	**500**	**800**	**800**
Capex per MW		€900,000	€864,000	€829,440	€796,262	
ITC Cost Limit		100%	100%	100%	100%	
ITC Rate		0%	0.00%	0.00%	0.00%	
ITC Cost		**€0**	**€0**	**€0**	**€0**	
Support Price per MWh						
	2017	€126	€129	€131	€134	€0
	2018		€122	€124	€127	€0
	2019			€118	€120	€0
	2020				€114	€0
Market Price per MWh		€60.32	€55.68	€53.36	€56.84	€79.69
Support Cost						
	2017	€9,665,994	€10,719,717	€11,439,428	€11,313,129	€0
	2018		€9,721,141	€10,418,859	€10,273,569	€0
	2019		€0	€12,633,184	€12,414,292	€0

	2020		€0	€0	€16,756,949	€0
Total Support Cost		**€9,665,994**	**€20,440,858**	**€34,491,470**	**€50,757,939**	**€0**
Total Support Cost (incl. ITC)		**€9,665,994**	**€20,440,858**	**€34,491,470**	**€50,757,939**	**€0**
Losses Avoided		€0	€0	€0	€0	€0
Tax Liability per MW						
	2017	€0	€0	€0	€0	€2,913
	2018		€0	€0	€0	€2,890
	2019			€0	€0	€2,867
	2020				€0	€2,844
Total Tax Paid		**€0**	**€0**	**€0**	**€0**	**€2,297,268**
Net Cost to Taxpayer		**€9,665,994**	**€20,440,858**	**€34,491,470**	**€50,757,939**	**-€2,297,268**
NPV of Subsidy		**€530,556,198**				

For clarity the years 2021 through 2040 were omitted from the table. They are included in the NPV calculation of the subsidy and may be found in the attached Excel financial model.

AVA Scenario

Assumptions

Revenue	
Installed Capacity (MW)	5
Capacity Factor	11.2%
Capacity Factor Annual Degradation	0.4%
Energy Inflation	2.0%
General Inflation	2.0%
Distribution Loss Adjustment Factor	1.006

CapEX

	per MW	Total
Engineering Procurement & Construction	€900,000	€4,500,000
Grid Connection Costs	€80,000	€400,000
Total CapEX		**€4,900,000**
Investment Tax Credit		€0
Net CapEX		**€4,900,000**

Project Lifetime (Years)	25
Loan Term (Years)	15
Interest Rate	4.5%
Debt:Equity Ratio	70%
National Development Finance Agency Discount Rate	4.0%
Weighted Average Cost of Capital	5.4%
Capital Allowances (Years)	1
Tax Rate	12.5%
Depreciation (Years)	25
Debt Maintenance Reserve	50%

Investment Tax Credit (ITC)	
ITC Cap	€70,000,000
ITC Cost Limit	100%
ITC Rate	0.0%

OpEX	
O&M Costs (per MW)	€15,000
Rent per MW	€5,500
Insurance per MW	€2,000
Business Rates per MW	€5,000
Grid Fees (% of Gross Revenue)	1.5%
Miscellaneous Costs per MW	€1,500

AVA Scenario Income Statement

Total Revenue	€13,797,167
Total OpEX	€4,851,351
EBIT	**€8,945,816**
Interest	€1,360,705
Depreciation	€4,900,000
Tax	€335,639
Retained Profit	**€2,349,472**

AVA Scenario Balance Sheet

Balance Sheet	**End Year 1**	**End Year 25**
Fixed Assets		
Opening	€4,900,000	€196,000
Depreciation	€196,000	€196,000
Closing	**€4,704,000**	**€0**
Cash Balance	€143,246	€3,819,472
Net Assets	**€4,847,246**	**€3,819,472**
Loan	€3,264,970	€0
Investment Tax Credit	€0	€0
Total Net Assets	**€1,582,276**	**€3,819,472**
Financed By		
Shareholders	€1,470,000	€1,470,000
Retained Profit	€112,276	€2,349,472
	€1,582,276	**€3,819,472**

AVA Scenario Support Costs

		2017	2018	2019	2020	2041
Projected MW Deployment						
	2017	150	150	150	150	150
	2018		150	150	150	150
	2019			200	200	200
	2020				300	300
Total Subsidised MW		**150**	**300**	**500**	**800**	**800**
Capex per MW		€900,000	€864,000	€829,440	€796,262	
ITC Cost Limit		100%	100%	100%	100%	
ITC Rate		0%	0.00%	0.00%	0.00%	
ITC Cost		**€0**	**€0**	**€0**	**€0**	
Support Price per MWh						
	2017	€125	€128	€130	€133	€0
	2018		€121	€123	€126	€0
	2019			€117	€119	€0
	2020				€113	€0
Market Price per MWh		€60.32	€55.68	€53.36	€56.84	€79.69
Support Cost						
	2017	€9,518,826	€10,569,606	€11,286,314	€11,156,953	€0
	2018		€9,574,562	€10,269,348	€10,121,068	€0
	2019		€0	€12,437,745	€12,214,944	€0
	2020		€0	€0	€16,463,790	€0

Total Support Cost	€9,518,826	€20,144,167	€33,993,406	€49,956,755	€0
Total Support Cost (incl. ITC)	€9,518,826	€20,144,167	€33,993,406	€49,956,755	€0
Losses Avoided	€53,263	€98,332	€157,058	€267,681	€375,277
Tax Liability per MW					
2017	€0	€0	€0	€0	€2,965
2018		€0	€0	€0	€2,942
2019			€0	€0	€2,918
2020				€0	€2,895
Total Tax Paid	€0	€0	€0	€0	€2,338,059
Net Cost to Taxpayer	€9,465,563	€20,045,836	€33,836,349	€49,689,075	-€2,713,336
NPV of Subsidy	€516,214,131				

ITC Scenario

Assumptions

Revenue

Installed Capacity (MW)	5
Capacity Factor	11.2%
Capacity Factor Annual Degradation	0.4%
Energy Inflation	2.0%
General Inflation	2.0%
Distribution Loss Adjustment Factor	1.006

CapEX

	per MW	Total
Engineering Procurement & Construction	€900,000	€4,500,000
Grid Connection Costs	€80,000	€400,000
Total CapEX		**€4,900,000**
Investment Tax Credit		€1,568,000
Net CapEX		**€3,332,000**

Project Lifetime (Years)	25
Loan Term (Years)	15
Interest Rate	4.5%
Debt:Equity Ratio	70%
National Development Finance Agency Discount Rate	4.0%
Weighted Average Cost of Capital	3.8%
Capital Allowances (Years)	1
Tax Rate	12.5%
Depreciation (Years)	25
Debt Maintenance Reserve	50%

Investment Tax Credit (ITC)

ITC Cap	€70,000,000
ITC Cost Limit	100%
ITC Rate	32.0%

OpEX

O&M Costs (per MW)	€15,000
Rent per MW	€5,500
Insurance per MW	€2,000
Business Rates per MW	€5,000
Grid Fees (% of Gross Revenue)	1.5%
Miscellaneous Costs per MW	€1,500

ITC Scenario Income Statement

Total Revenue	€11,228,130
Total OpEX	€4,812,815
EBIT	**€6,415,315**
Interest	€925,280
Depreciation	€3,332,000
Tax	€269,754
Retained Profit	**€1,888,281**

ITC Scenario Balance Sheet

Balance Sheet	**End Year 1**	**End Year 25**
Fixed Assets		
Opening	€4,900,000	€1,701,280
Depreciation	€133,280	€133,280
Closing	**€4,766,720**	**€1,568,000**
Cash Balance	€94,756	€2,887,881
Net Assets	**€4,861,476**	**€4,455,881**
Loan	€2,220,179	€0
Investment Tax Credit	€1,568,000	€1,568,000
Total Net Assets	**€1,073,297**	**€2,887,881**
Financed By		
Shareholders	€999,600	€999,600
Retained Profit	€73,697	€1,888,281
	€1,073,297	**€2,887,881**

ITC Scenario Support Costs

		2017	2018	2019	2020	2041
Projected MW Deployment						
	2017	150	150	150	150	150
	2018		150	150	150	150
	2019			200	200	200
	2020				300	300
Total Subsidised MW		**150**	**300**	**500**	**800**	**800**
Capex per MW		€900,000	€864,000	€829,440	€796,262	
ITC Cost Limit		100%	100%	100%	100%	
ITC Rate		32%	27.00%	22.00%	17.00%	
ITC Cost		**€43,200,000**	**€34,992,000**	**€36,495,360**	**€40,609,382**	
Support Price per MWh						
	2017	€94	€96	€98	€100	€0
	2018		€90	€92	€94	€0
	2019			€86	€88	€0
	2020				€82	€0
Market Price per MWh		€60.32	€55.68	€53.36	€56.84	€79.69
Support Cost						
	2017	€4,956,618	€5,916,154	€6,539,793	€6,315,502	€0
	2018		€5,030,603	€5,634,509	€5,393,533	€0
	2019		€0	€6,379,132	€6,035,160	€0
	2020		€0	€0	€7,375,872	€0

Total Support Cost		**€4,956,618**	**€10,946,756**	**€18,553,434**	**€25,120,066**	**€0**
Total Support Cost (incl. ITC)		**€48,156,618**	**€45,938,756**	**€55,048,794**	**€65,729,448**	**€0**
Losses Avoided		€53,263	€98,332	€157,058	€267,681	€375,277
Tax Liability per MW						
	2017	€0	€0	€0	€0	€2,965
	2018		€0	€0	€0	€2,942
	2019			€0	€0	€2,918
	2020				€0	€2,895
Total Tax Paid		**€0**	**€0**	**€0**	**€0**	**€2,338,059**
Net Cost to Taxpayer		**€48,103,355**	**€45,840,424**	**€54,891,737**	**€65,461,767**	**-€2,713,336**
NPV of Subsidy		**€361,484,352**				