Single Electricity Market

All-Island Generator Transmission Use of System (TUOS) charging

Decision Paper

28 August 2012

SEM-12-074a

Contents

Background

The development of harmonised Generator Transmission Use of System (GTUoS) tariffs has been an objective of the Regulatory Authorities since the outset of the Single Electricity Market (SEM). This was identified in SEM High Level Design Paper (AIP/SEM/42/05 – June 2005) which stated that the costs borne by the Generator should reflect those being imposed on the transmission system.

"Generators should pay a locational charge as part of their TUoS – i.e. they should pay more to contribute to the cost of the deep reinforcement which their shallow connection has caused"

Historically, different transmission charging methodologies have been applied in Northern Ireland and Republic of Ireland. Northern Ireland used a non-locational £/MW capacity charge and levied it on all generators, whereas the Republic of Ireland adopted a system whereby GTUoS charges varied by location. Following the publication of the High Level Design a project was put in place to harmonise Generator TUoS across the SEM. After a period of consultation, draft all-island GTUoS tariffs were developed for the 2008/2009 tariff period. Concerns were raised by participants around the volatility between years and the robustness of the methodology, resulting in the SEM Committee ruling against their implementation.

In January 2009 the SEM Committee decided to combine GTUoS with the ongoing TLAF work stream. A locational signals project was initiated, the aim of which was to address previous concerns raised by participants. In the summer of 2010 the work streams separated with the publication of a decision on all-island TLAFs (SEM-10-066) in September of that year.

In December 2010, following a period of discussion between the Regulatory Authorities, consultants (Poyry) and the System Operators, the SEM Committee published its decision on GTUoS (SEM-10-081). It was decided to implement a Dynamic plus postage stamp methodology. The postage stamp element was designed to ensure stability with the locational element acting as a signal to show generators where to construct.

In the following months a range of consultations took place on the methodology, tariffs and other areas in need of clarification. Following a series of consultations with participants (SEM-11-018, SEM-11-036 and SEM-11-037) the GTUoS project committee published indicative tariffs and a Generator TUoS Methodology Statement for consultation in May 2011. A decision paper was approved by a special SEM Committee on 12 September 2011 (SEM/11/078). In its approval, the SEMC requested the Regulatory Authorities and TSOs investigate further refinements to the methodology for the following tariff year (2012/2013).

Throughout the winter of 2011 the Regulatory Authorities and TSOs studied the recommended refinements and agreed on a number of amendments to the GTUoS methodology that would be used in collating the 2012/2013 tariffs. These modifications were subsequently incorporated into the methodology and appropriate adjustments to the systems computing the tariffs were made.

At the May 2012 SEM Committee the TSOs gave a presentation of the refinements made to the 2012/2013 GTUoS tariff methodology, as requested by the SEM Committee at their meeting on the 12 September 2011. Following the presentation and subsequent discussion the SEM Committee made a minded to decision to accept tariff set 2b, the new methodology tariff including old rule set. The SEM Committee also asked that the Regulatory Authorities investigate the possibility of further developing the range of scenarios used in the methodology.

A four week consultation was put to Industry on the 14th June. This included a breakdown of the three tariff sets submitted by the Transmission System Operators (TSOs), a methodology paper outlining the amendments made to the methodology in each of the three tariffs and a GTUoS cover note from the Regulatory Authorities (RAs) detailing the minded to decision. Responses have been published along with the decision paper.

Summary of tariff Sets

Three sets of tariffs were provided by the TSOs based on two methodologies as requested by the Regulatory Authorities and the SEM Committee.

Tariff set 1 was based on the default 2011/2012 methodology. Four different dispatch scenarios are included in the model. The cost base includes assets planned to be constructed within the next 5 years and a Y+5 dispatch scenario is applied to a future network in order to determine the impact generators today have on future network build.

Tariff set 2a is based on the new methodology tariff including new rule set following a review of SEM Committee requested items. The 1 MW function is used and four dispatch scenarios are included in the model. However, a refinement has been made to the four dispatch scenarios for out of merit plant. To derive a tariff for these Generators that are out-of-merit and not dispatched two of the scenarios (Summer Min 80% wind and summer Peak 80% wind) are discounted. The impact of this is that 2 out of the 4 scenarios are discounted, resulting in a reduced number of scenarios applying for certain generators. This was deemed to be a reasonable assumption as the likelihood of these generators ever being dispatched in these two scenarios is slim.

Tariff set 2a also includes a wider cost base as both assets planned in the next 5 years and historical assets are included. Historical assets are only removed seven years post commissioning or twelve years after introduction, whichever occurs first. Intermediate years have also been included in the dispatch scenarios.

Tariff set 2b is based on the new methodology tariff including old rule set. Four dispatch scenarios are included in the model with the 1MW function used in all scenarios, even when a plant is out-of-merit and not dispatched. A wider cost base is also used, as in tariff set 2a, along with the inclusion of intermediate years in the dispatch scenario.

GTUoS Consultation and Regulatory Authorities response

Ten responses were received on the GTUoS methodology and minded to decision consultation. All of these were non-confidential and have been published on the AIP website along with this paper.

- Endesa Ireland
- AES NI
- Power NI Energy - Power Procurement
- ABO Wind Ireland Ltd
- ESB Power Generation
- Bord Gáis Energy
- Irish Wind Energy Association
- SSE Renewables
- Northern Ireland Renewables Industry Group
- Energia

An outline to the responses to the consultation and other general comments has been broken into two sections;

- Respondents views on the changes in methodology and preferred tariff set; and
- Other Issues raised by Respondents.

Respondent's views on the changes in methodology and preferred tariff set

Calculation Methodology for All Island GTUoS Tariffs and preferred tariff set

Opinions from respondents as to a preferred tariff set were varied with no consensus being reached. Some respondents favoured maintaining the status quo (tariff set 1), with one respondent stating that amendments to the GTUoS methodology "*creates an increasing impediment that potentially serves to frustrate the policy of facilitating more renewable generation on the system.*"

Other respondent's favoured tariff set 2a with one stating that 2a "*provide a fairer result because they apply the 0% wind scenarios to thermal generators not in merit and the 80% wind scenarios to wind generators".* Support for the minded to decision was also expressed. Other respondents raised concerns with the changes in methodology in tariff sets 2a and 2b and the impacts that the changes have brought about for renewable generators in particular.

Regulatory Authorities Response

The Regulatory Authorities acknowledge that there has been support amongst respondents for both methodologies, with different respondents stating their support for all three tariff sets. The changes in the tariff methodology have impacted upon generators in different ways as the locational signal, which accounts for 30% of a generators tariff, will differ for each generator. The broad range of responses received on the preferred tariff set has reflected the varying impacts that the change in methodology has brought about, as would be expected.

It is the Regulatory Authorities view that changes to the methodology have resulted in a more robust approach to the setting of GTUoS tariffs and should result in more stable tariff sets going forward. The changes to the methodology, along with respondent's views and their impact, are discussed in greater detail in this paper.

Use of Intermediate Years in the amended methodology

A number of respondents were supportive of the use of intermediate years in the new methodology. One of the respondents commented that this was a welcome amendment to the methodology with another stating *"the proposed changes are likely to lead to more stable tariffs".*

Regulatory Authorities Response

The Regulatory Authorities welcome the fact that some respondents have recognised the contribution the inclusion of intermediate years brings to the updated methodology. The Regulatory Authorities consider that the inclusion of intermediate years increases the stability and predictability of tariffs, without impacting the signal that would be sent when compared with the default methodology.

Without the inclusion of intermediate years dispatch will specifically assess the forecast in the year Y+5. This fails to capture the network evolution that will occur in the years leading up to that point. It is considered that the capture of intermediate years will lead to a more stable tariff set, and one which more accurately reflects the network flows.

Inclusion of Historical Assets

There were polarised views on the inclusion of historical assets in the new methodology with some respondents supporting its inclusion and others arguing that it should be removed.

Of those that supported the inclusion of historical assets one respondent stated that they welcomed *"the inclusion of the historical assets within the modelling cost base as it provides an element of stabilisation to the tariff setting methodology".* This was in contrast to other participants that felt historical assets are inconsistent with the objectives of the GTUoS charge and should be excluded. With generators needing to secure project financing, planning and construction before connection it was felt by one respondent that that the *"chances of a confluence of events conspiring to allow a generator to benefit from lower GTUoS charges appear remote".*

Regulatory Authorities Response

The Regulatory Authorities consider that the inclusion of historical assets in the new methodology is justified. It is only fair that a generator pays for the assets which it has driven the construction of. It is unreasonable to expect a generator to pay for the entire cost of the network reinforcement in an area only for others to experience the benefits a short time later. It may not be the case that other generators have done this deliberately, but the inclusion of historical assets in the cost base prevents a potential free-rider scenario from occurring.

The Regulatory Authorities judge that not enough evidence has been provided to suggest that this type of scenario would not exist and that the inclusion of historic assets helps to create a fairer tariff model, whereby generators pay their share of the network costs.

Other Issues raised by Respondents

Equal Treatment of Firm and Non-firm Generators in the market.

A number of respondents disagree with the equal treatment of firm and non-firm generators. Equal treatment of firm and non-firm was considered by some to be inappropriate with one respondent stating

"Consideration needs to be given to the fact that non-firm generators are not compensated when constrained, therefore charging non-firm and firm generators on a like for like basis for TUoS is not appropriate…..TUoS charge for all generators should be levied on a per MWh exported basis as it aligns generator income with these payments".

Another participant felt that treatment of firm and non-firm generators cannot be described as a fair allocation of costs and that a generator should not have to pay for capacity in which it has no guaranteed access.

Regulatory Authorities Response

The Regulatory Authorities strongly support the equal treatment of firm and non-firm generation. Looking back on the formulation and establishment of the GTUoS methodology one of the overriding principles has been one of fairness. That is all generators should be charged on the basis of their anticipated usage of the transmission network.

Essentially all generators are charged on their estimated responsibility in the expansion of the transmission network. There is no distinction between generators that are firm and those that are non-firm. It is considered to be only fair that non-firm generators should pay for the existing assets on the system and the future assets in which they are driving.

All generators effectively get access to the market schedule by virtue of their competitive position in the merit order.

Fixing of the TUOS tariff rates for a period of time

Some respondents stated their support for a fixing of the GTUoS rate for a period of 5 years. One respondent felt that fixing of the GTUoS charge for a period of 5 years would mitigate risk as a generator cannot respond to an annually adjusting signal once built. Another felt that the consultation had not addressed the outstanding query from SEM-11-078 whereby fixing of the GTUoS rate would be considered. A timescale of fixing for a period of 5 years was mentioned.

Regulatory Authorities Response

The Regulatory Authorities recognise that fixing GTUoS tariffs for a period of time would bring a degree of stability for generators. This stability would give existing generators and future investors a level of certainty so they can choose a site with the best possible information. This was an issue that was raised in the previous tariff year and it was agreed that this would be looked into.

The Regulatory Authorities came to the conclusion that the drawbacks accompanying the fixing of tariffs still outweigh the benefits. With large scale investments in the transmission network expected over both the short and long term, it is considered that a fixing of the tariff for a period of five years will not be cost reflective. Fixing the tariffs for a period will also increase the likelihood of a large step change in tariffs for generators at the end of the period, just exposing them to increased risk over the longer term. It can be argued that several large shifts in a generator tariff do not provide a greater degree of stability than smaller annual changes.

By its very nature fixing a tariff for a period will take a snapshot of how the system is running and carry this through for a number of years. The network and its flows will evolve over this timeframe and the Regulatory Authorities consider that tariffs should reflect this evolvement. In saying that the Regulatory Authorities believe option of freezing tariffs for a period should not be discounted and kept open. Stability and predictability are also key elements of GTUoS tariffs along with cost reflectivity. The positive responses on this issue have been noted and it is the intention of the Authorities to continue to look into the possibility of fixing the tariffs, or the methodology, for a period to provide a stable and reliable signal to both generators and investors.

Inclusion of the second North-South tie line in the Modelling

Respondents have questioned the use of the second North-South Tie line in the modelling. It was felt that the construction of the tie-line, in the current envisaged timelines, was unlikely and that it should be excluded from the cost base.

Regulatory Authorities Response

To date there has been no announcements concerning any delays in the construction of the North-South Tie line. While this remains the case the Regulatory Authorities currently accept the TSOs position that construction will be complete by 2017.

Concern regarding the change in tariff rates between 2012/13 and 2011/12

A number of respondents raised concerns regarding the volatility between 2012/2013 and 2011/2012 tariffs. It was generally felt that the magnitude of change is failing to provide generators with a reliable signal to construct. One respondent noted that the proposed Methodology does not meet the objectives of *'stability', 'predictability' and 'cost-reflectiveness'*

Other participants were particularly concerned with the effect tariff changes are having on renewable generators, with another respondent commenting on the *"significant impact the new methodology has on the tariffs for wind farms, with most wind farms seeing a significant increase in tariffs".*

Regulatory Authorities Response

As part of its decision on GTUoS rates for 2011/2012, the SEM Committee outlined further refinements to the GTUoS methodology. In carrying out the refinements to the methodology tariff rates have changed, with the changes affecting some generators more than others. While the Regulatory Authorities acknowledge that this has led to significant changes in some of the rates this is compensated by the fact that a more robust methodology has been developed and put in place.

With the new methodology in place and the amendments included, levels of volatility should decrease in the coming years, resulting in a more stable, predictable and cost reflective tariff.

Impacts of Grid 25 and 30% locational element on the tariffs

Two respondents had concerns over how *Grid25* will impact upon the tariffs and that the consultation has not addressed this issue. One of the respondents felt that this issue was key, as these large scale projects *"are likely to further increase the average TUoS for windfarms and so would provide a lot of concern to the sector"*.

Respondents also raised the question of reducing the 30% locational aspect of the GTUoS tariff. It was suggested that the locational element be reduced from its current level of 30% to 10% - 15%. One respondent felt that the locational element serves *"only to create a split between wind generators and conventional generators."*

Regulatory Authorities Response

The long-term impact of *Grid25* on tariffs is outside the scope of the consultation, as the generator tariffs published are based on an annual (1 October 2012 to 30 September 2013) all-island requirement, determined by the Regulatory Authorities. As a result, it is not possible to identify all the specific elements related to *Grid25*. The model includes assets which are both in *Grid25* and outside of *Grid25*.

Weighting of the locational element of GTUoS was not an element that was identified for further examination in SEM-11-078. Currently the postage stamp element makes up 70% of the charge with the locational forward looking element making up the remaining 30%. The Regulatory Authorities consider that the locational element of the tariff is important as it acts as a signal to generators at the time they are making investment decisions. The promotion of appropriate locational decisions is key to managing generator access to the transmission network and to minimizing inefficient congestion. A weak locational signal would result in new entrants not being exposed to the costs that they impose as a result of their locational decisions.

Concern whether all areas identified for further examination have been looked into

Respondents have raised concerns whether all aspects identified for further examination in SEM-11-078 have been identified.

Regulatory Authorities Response

Over the course of the past year all areas identified for further examination have been examined by both the RA's and the TSO's. Many of these areas and the decisions taken have already been examined in detail in this paper.

One of the areas noted and not yet commented upon was a 'complete report of advantages of average participation versus marginal participation'. A number of studies and discussion have been carried out on this issue by the TSOs over the past number of years and no conclusive evidence has been provided to-date that a move away from marginal participation is warranted. However, the Regulatory Authorities do note that the TSOs have committed to continue researching methodologies for calculating participation factors in order to determine whether marginal participation is still a better approach than average participation.

Another point made was that the consultation did not comment on the "expansion or refinement of the four scenarios in discussion with transmission planning, including consideration of the use of plant not dispatched setting tariffs". Discussions did take place between the Regulatory Authorities and the TSO's on this issue, with the outcome being that tariff sets would stay the same, but a modified rule set (tariff set 2a) would be developed for plant not in merit. This issue was highlighted at the SEM Committee and it was agreed that the Regulatory Authorities would look into the possibility of either refining the 4 scenarios currently in use or adding extra scenarios to the methodology.

SEM Committee Decision

Following a review of consultation responses the SEM Committee has decided to uphold its minded to decision to recommend tariff set 2b, the new methodology tariff including old rule, be used for 2012/2013 GTUoS tariffs.

The SEM Committee believes the methodology in tariff set 2b gives a more stable set of results and will result in a fairer allocation of costs. This is evident in the range of tariffs being seen in the two sets.

As part of its decision the SEM Committee has asked the Regulatory Authorities and TSOs to look into the four scenarios used in computing the tariffs and assess whether these should be refined or more scenarios added, so that planning is better represented.

The following is the allowed revenues to be recovered in line with the tariffs for the tariff year 2012/2013:

ROI Revenue	€ 50,262,438
NI Revenue	€ 12,541,262
All Island Revenue	€ 62,803,700

Appendix A: Final All Island GTUoS Tariffs 2012/13

The below GTUoS tariffs are applicable for the tariff period 1 October 2012 to 30 September 2013 only. They are reflective of the decisions outlined in this paper.

Station	Units	Contracted Maximum Export Capacity (MW)	Network Capacity Charge Rate €/MW/month	Equivalent €/kW/year
ROI Transmission Connected Non-Wind				
Aghada 220kV (including Longpoint)	AD1, AT1, AT2, AT4, AD2	959	**579.2441**	**6.9509**
Ardnacrusha	AA1, AA2, AA3, AA4	86	**421.15**	**5.0538**
Aughinish (Seal Rock)	SK3, SK4	130	**483.4667**	**5.8016**
Dublin Bay Power (Irishtown)	DB1	415	**410.9167**	**4.931**
Edenderry Power (Cushaling)	ED1	121.5	**417.1167**	**5.0054**
Edenderry Peaker (Cushaling)	ED3, ED5	116	**417.1**	**5.0052**
Erne (Cathleen's Fall)	ER3, ER4	45	**734.3417**	**8.8121**
Erne (Cliff)	ER1, ER2	20	**734.3417**	**8.8121**
Whitegate CCGT (Glanagow)	WG1	445	**568.1**	**6.8172**
Great Island 110kV	GI1, GI2	108	**373.8583**	**4.4863**
Great Island 220kV	GI3	108	**412.9167**	**4.955**
Huntstown 1	HNC	352	**415.8083**	**4.9897**
Huntstown 2	HN2	412	**417.9833**	**5.0158**
Lough Ree Power (Lanesboro)	LR4	94	**425.925**	**5.1111**
Lee (Carrigadrohid)	LE3	8	**562.2917**	**6.7475**
Lee (Inniscarra)	LE1, LE2	19	**544.275**	**6.5313**
Liffey (Pollaphuca)	LI1, LI2, LI4	34.18	**375.425**	**4.5051**
Marina	MR1, MRT	112	**481.5**	**5.778**
Moneypoint	MP1, MP2, MP3	862.5	**505.8917**	**6.0707**
Northwall 220kV	NW4, NW5	227	**413.925**	**4.9671**
Poolbeg (Shellybanks)	PB4,PB5, PB6	460	**411.5083**	**4.9381**
Rhode (Derryiron)	RH1, RH2	103.6	**377.9917**	**4.5359**
Tarbert 110kV	TB1, TB2	108	**484.4583**	**5.8135**
Tarbert 220kV	TB3, TB4	481.4	**484.4583**	**5.8135**
Turlough Hill	TH1, TH2, TH3, TH4	292	**423.3167**	**5.0798**
Tynagh	TYC	404	**457.05**	**5.4846**

Station	Units	Contracted Maximum Export Capacity (MW)	Network Capacity Charge Rate €/MW/month	Equivalent €/kW/year
West Offaly Power (Shannonbridge)	WO4	141	**431.7417**	**5.1809**
ROI Transmission Connected Wind				
Boggeragh	Boggeragh (1)	57	**587.3833**	**7.0486**
Booltiagh	Booltiagh (1), Booltiagh (2),Booltiagh (3)	31.45	**451.575**	**5.4189**
Castledockrell	Castledockrell (1), Castledockrell (2), Castledockrell (3), Castledockrell (4)	41.4	**497.7583**	**5.9731**
Coomagearlahy	Coomagearlahy (1), Coomagearlahy (2), Coomagearlahy (3)	81	**657.9833**	**7.8958**
Crane	Ballywater (1), Ballywater (2)	42	**410.2**	**4.9224**
Cunghill	Kingsmountain (1), Kingsmountain (2)	34.8	**546.1333**	**6.5536**
Derrybrien	Derrybrien (1)	59.5	**426.9417**	**5.1233**
Dromada	Dromada (1)	46	**544.1667**	**6.53**
Garrow	Coomacheo (1), Coomacheo (2)	59.225	**660.9**	**7.9308**
Garvagh	Garvagh (1a)	58.23	**677.4**	**8.1288**
Glanlee	Glanlee (1)	29.8	**657.9833**	**7.8958**
Golagh	Golagh (1)	15	**819.7583**	**9.8371**
Kill Hill	Kill Hill (1)	58.5	**537.6**	**6.4512**
Lisheen	Lisheen (1)	55	**487.45**	**5.8494**
Meentycat	Meentycat (1), Meentycat (2)	84.96	**855.5333**	**10.2664**
Mulreavy	Mulreavy (1)	82	**734.4**	**8.8128**
Pallas	Clahane (1)	37.8	**552.25**	**6.627**
Ratrussan	Mountain Lodge (1)	30.62	**364.6917**	**4.3763**
Ratrussan	Ratrussan (1a)	70	**364.6917**	**4.3763**
ROI Distribution Connected				
Ardnacrusha	Knockastanna (1)	7.5	**421.1583**	**5.0539**

Station	Units	Contracted Maximum Export Capacity (MW)	Network Capacity Charge Rate €/MW/month	Equivalent €/kW/year
Arklow	Arklow Bank (1)	25.2	**403.3667**	**4.8404**
Ballylickey	Kealkil (Curraglass) (1)	8.5	**475.25**	**5.703**
Ballylickey	Glanta Commons (1), Glanta Commons (2), Glanta Commons (2a)	39.45	**475.25**	**5.703**
Bandon	Kilvinane (2)	5.82	**489.1583**	**5.8699**
Bellacorick	Bellacorick (1)	6.45	**554.6583**	**6.6559**
Binbane	Meenachullalan (1)	11.9	**604.1417**	**7.2497**
Binbane	Corkermore (1)	15	**604.1417**	**7.2497**
Binbane	Loughderryduff (1)	7.65	**604.1417**	**7.2497**
Boggeragh	Carrigcannon (1)	20	**587.3833**	**7.0486**
Carlow	Gortahile (1)	21	**377.0583**	**4.5247**
Castlebar	Raheen Barr (1)	18.7	**426.4167**	**5.117**
Castlebar	Raheen Barr (2)	8.5	**426.4167**	**5.117**
Cauteen	Glenough (1)	33	**466.7333**	**5.6008**
Cauteen	Holyford (1)	9	**466.7333**	**5.6008**
Cauteen	Garracummer (1)	36.9	**466.7333**	**5.6008**
Cauteen	Cappagh White (1)	16.1	**466.7333**	**5.6008**
Corderry	Tullynamoyle (1)	9	**677.4**	**8.1288**
Corderry	Black Banks (2)	6.8	**677.4**	**8.1288**
Corderry	Altagowlan (1)	7.65	**677.4**	**8.1288**
Crory	Gibbet Hill (1)	14.8	**497.7583**	**5.9731**
Crory	Ballycadden (1), Ballycadden (2)	25.95	**497.7583**	**5.9731**
Dunmanway	Coomatallin (1)	5.95	**475.25**	**5.703**
Dunmanway	Milane Hill (1)	5.94	**475.25**	**5.703**
Garrow	Caherdowney (1)	10	**660.9**	**7.9308**
Glenlara	Taurbeg (1)	26	**537.7333**	**6.4528**
Glenlara	Dromdeeveen (1), Dromdeeveen (2)	27	**537.7333**	**6.4528**
Glenree	Carrowleagh (1)	34.15	**549.575**	**6.5949**

Station	Units	Contracted Maximum Export Capacity (MW)	Network Capacity Charge Rate €/MW/month	Equivalent €/kW/year
Knockacummer	Knockacummer (1)	87	**537.7333**	**6.4528**
Knockearagh	Gneeves (1)	9.35	**611.8**	**7.3416**
Letterkenny	Cark (1)	15	**874.5667**	**10.4948**
Letterkenny	Culliagh (1)	11.88	**874.5667**	**10.4948**
Macroom	Bawnmore (1)	24	**563.375**	**6.7605**
Macroom	Garranereagh (1)	8.75	**563.375**	**6.7605**
Meath Hill	Mullananalt (1)	7.5	**427.7583**	**5.1331**
Meath Hill	Gartnaneane (1)	10	**427.7583**	**5.1331**
Moy	Lackan (1)	6	**551.3333**	**6.616**
Northwall 38kV	NW1, NW2, NW3	45	**415.8**	**4.9896**
Oughtragh	Knockaneden (1)	9	**560.3917**	**6.7247**
Rathkeale	Rathcahill (1)	12.5	**477.65**	**5.7318**
Rathkeale	Grouse Lodge (1)	15	**477.65**	**5.7318**
Somerset	Sonnagh Old (1)	7.65	**417.7167**	**5.0126**
Sorne Hill	Sorne Hill (1), Sorne Hill (2)	38.9	**874.5667**	**10.4948**
Sorne Hill	Flughland (1)	9.2	**874.5667**	**10.4948**
Tawnaghmore	Tawnaghmore Peaker	104	**551.3**	**6.6156**
Tonroe	Largan Hill (1)	5.94	**421.3333**	**5.056**
Tralee	Muingnaminnane (1)	15.3	**534.6917**	**6.4163**
Tralee	Mount Eagle (1)	5.1	**534.6917**	**6.4163**
Tralee	Tursillagh (1)	15	**534.6917**	**6.4163**
Tralee	Tursillagh (2)	6.8	**534.6917**	**6.4163**
Tralee	Ballincollig Hill (1)	15	**534.6917**	**6.4163**
Trien	Tournafulla (2)	17.2	**564.4833**	**6.7738**
Trien	Knockawarriga (1)	22.5	**564.4833**	**6.7738**
Trien	Tournafulla (1)	7.5	**564.4833**	**6.7738**
Trillick	Drumlough Hill (2)	9.99	**874.5667**	**10.4948**
Trillick	Beam Hill (1)	14	**874.5667**	**10.4948**
Tullabrack	Moanmore (1)	12.6	**435.4083**	**5.2249**
Waterford	Ballymartin (1), Ballymartin (2)	14.28	**367.1917**	**4.4063**

Station	Units	Contracted Maximum Export Capacity (MW)	Network Capacity Charge Rate €/MW/month	Equivalent €/kW/year
Wexford	Richfield (1), Richfield (2)	27	**383.1167**	**4.5974**
Wexford	Carnsore (1)	11.9	**383.1167**	**4.5974**
Dunmanway	Carbery Milk Products CHP (1)	6	**475.25**	**5.703**
Barrymore	Dairygold Mitchelstown	8.55	**468.7083**	**5.6245**
Inchicore	Guinness CHP (1)	7	**405.75**	**4.869**
Drybridge	Meath Waste-Energy (1)	17	**412.15**	**4.9458**
NI Transmission Connected				
Ballylumford	Ballylumford	170	**435.6167**	**5.2274**
Ballylumford	Ballylumford	170	**435.6167**	**5.2274**
Ballylumford	Ballylumford	170	**435.6167**	**5.2274**
Ballylumford	Ballylumford	53	**434.4833**	**5.2138**
Ballylumford	Ballylumford	53	**434.4833**	**5.2138**
Ballylumford	Ballylumford	157	**435.625**	**5.2275**
Ballylumford	Ballylumford	157	**435.625**	**5.2275**
Ballylumford	Ballylumford	180	**435.625**	**5.2275**
Ballylumford	Ballylumford	98.4	**434.4833**	**5.2138**
Coolkeeragh	Coolkeeragh	53	**447.75**	**5.373**
Coolkeeragh	Coolkeeragh	170	**447.7667**	**5.3732**
Coolkeeragh	Coolkeeragh	243	**452.3583**	**5.4283**
Kilroot	Kilroot	240	**432.175**	**5.1861**
Kilroot	Kilroot	240	**432.175**	**5.1861**
Kilroot	Kilroot	42	**432.175**	**5.1861**
Kilroot	Kilroot	42	**432.175**	**5.1861**
Kilroot	Kilroot	23.6	**432.1833**	**5.1862**
Kilroot	Kilroot	23.6	**432.1833**	**5.1862**
Slievekirk	Slievekirk	47.6	**445.7333**	**5.3488**
NI Distribution Connected				
Aghyoule	Slieve Rushen2	54	**437.35**	**5.2482**
Aghyoule	Snugborough	13.5	**437.35**	**5.2482**

Station	Units	Contracted Maximum Export Capacity (MW)	Network Capacity Charge Rate €/MW/month	Equivalent €/kW/year
Carnmoney	Carn Hill	13.8	429.1	5.1492
Coleraine	Garves	15	445.075	5.3409
Coleraine	Gruig	25	445.075	5.3409
Dungannon	Crockagarran	17.5	334.05	4.0086
Enniskillen	Callagheen	16.9	437.3583	5.2483
Killymallaght	Carrickatane	22.5	445.7333	5.3488
Larne	Wolf Bog	10	435.6083	5.2273
Limavady	Altahullion	26	446.1167	5.3534
Limavady	Altahullion2	11.7	446.1167	5.3534
Lisaghmore	Curryfree	15	447.7667	5.3732
Lisburn	Contour Global	9	423.6417	5.0837
Magherakeel	Thornog	10	437.3667	5.2484
Magherakeel	Church Hill	18.4	437.3667	5.2484
Magherakeel	Crigshane	32.2	437.3667	5.2484
Omagh	Bessybell2	9	472.725	5.6727
Omagh	Hunters Hill	20	472.725	5.6727
Omagh	Lendrum's Bridge	13.2	472.725	5.6727
Omagh	Screggagh	20	472.725	5.6727
Omagh	Slieve Divena1	30	472.725	5.6727
Omagh	Tappaghan	19.5	472.725	5.6727
Omagh	Tappaghan2	9	472.725	5.6727
Strabane	Bin Mountain	9	444.1833	5.3302
Strabane	Lough Hill	7.8	444.1833	5.3302
Strabane	Owenreagh	5.5	444.1833	5.3302
Strabane	Owenreagh2	5.1	444.1833	5.3302
	AGU		334.05	4.0086