Interface analysis and report for incorporation and alignment of data from biomethane study into RHI workstream

Final Report

for

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1 Introduction

This study was commissioned by the Sustainable Energy Authority of Ireland (SEAI) to incorporate the relevant aspects of the *Assessment of the costs and benefits of biogas and biomethane* study completed by Ricardo Energy & Environment for SEAI into the *Economic analysis for an RHI for Ireland* work undertaken by Element Energy for the Department of Communications, Climate Action and Environment (DCCAE). The primary aim of this work is to ensure the best information on biogas and biomethane technologies is included in the RHI analysis, and to include those technologies on the same basis as the other renewable heat technologies being examined. This work also ensured the alignment of data inputs across the two studies.

This report covers the following:

- Derivation of a set of scenarios for the tariffs within a Renewable Heat Incentive (RHI) scheme for anaerobic digestion (AD) and biomethane, using an approach consistent with that taken for the renewable heating technologies included in the *Economic analysis for an RHI for Ireland* work;
- An assessment of whether biomethane production should be incentivised through support to the producer or end user of the biomethane;
- An initial assessment of the potential to fund support for biomethane through a levy on gas consumers, focusing on an estimate of the size of the levy that would be required in a range of scenarios for RHI design and biomethane deployment;
- A preliminary assessment of the cost of supplying Bio-liquefied petroleum gas (BioLPG) in Ireland, and the size of the tariff required to support this through the RHI.

This report was prepared jointly by Ricardo Energy & Environment and Element Energy.

2 AD CHP, AD boiler and biomethane grid injection tariff design and uptake modelling

2.1 Tariff design

The tariffs for Anaerobic Digestion (AD) CHP, AD boiler and biomethane grid injection were determined using archetypes developed by Ricardo Energy & Environment in the *Assessment of the costs and benefits of biogas and biomethane* study. In this case, the archetypes relate to AD and biomethane installation types, differentiated by size, type of feedstock and heat load, as summarised in Table 1. The detailed cost and performance data for AD CHP, AD boiler and biomethane grid injection, and the data collection method, is presented in the final report for the *Assessment of the costs and benefits of biogas and biomethane* study[1].

Table 1: AD CHP, boiler and biomethane archetype parameters

Technology type	Size	Feedstock type	Heat load
AD CHP	• Small (<500 kW biogas) • Medium (500-3,000 kW biogas) • Large (≥3,000 kW biogas)	• Farm fed (dairy and pig slurry, grass silage, vegetable or food wastes generated on or off farm) • Waste fed (source-separated food waste, wastes from agri-food processing, waste sludges from industry)	• Low (10-20%) • Medium (40-60%) • High (60-80%)
AD boiler	• Small (<500 kW biogas) • Medium (≥500 kW biogas)	• Animal slurry and whey • Mixture of waste materials	• Low (60%) • Medium (80%) • High (85%)
Biomethane grid injection	• Medium (<3,000 kW biogas) • Large (≥3,000 kW biogas)	• Farm fed (pig and cattle slurry, grass silage, maize) • Waste fed (all food waste, mixture of waste materials) • Sewage sludge (waste water treatment primary sludge)	• N/A

[1] Ricardo Energy & Environment, *Assessment of the costs and benefits of biogas and biomethane* (Not yet published)

2.2 Uptake of AD CHP, AD boiler and biomethane grid injection

Given the circumstances in which many AD CHP and AD boiler plants are expected to be developed, which is largely in an agricultural context, an important source of uncertainty is the on-site heat demand. The heat from AD is not 'dispatchable', as the anaerobic digestion plant producing the biogas used for heat cannot be turned on and off on a frequent basis in the same way other heating systems can, and so the operating cost of the AD plant is independent of the heat load. The available on-site heat demand will therefore determine the heat load factor of the plant and the 'useful' proportion of heat generated, and will have an important bearing on the cost-effectiveness of generating renewable heat through these technologies. An important consideration in selecting the final scheme tariffs will be the need to provide a tariff sufficient to incentivise uptake of the desired type and number of installations, while not encouraging inefficient use of heat generated.

For each archetype for AD CHP and AD boiler, therefore, three cases were studied relating to the level of on-site heat demand; these are referred to as Low (LHL), Medium (MHL) and High (HHL) heat load cases. A separate RHI tariff was calculated for each heat load case. For biomethane grid injection, an operational load factor of 100% is assumed, i.e. all biomethane produced can be injected into the grid[2]. It is assumed that AD boiler systems would only be installed where a heat load is present so all heat load factors are relatively high. In the case of AD CHP plant, which are likely to be installed primarily for the production of electricity from biogas, in the worst case the only heat demand might be that required to ensure operation of the digester itself and any pasteurisation of feedstocks which is required, which leads to low (10 to 20%) heat loads depending on the feedstock.

[2] This is typically the case, although there could be instances, if gas is injected at points where summertime flows of natural gas are low due to reduced demand, when it may be necessary for grid operational reasons to temporarily suspend injection.

Table 2: Heat load factors by archetype for AD CHP and AD boiler

System ID	Heat load factor		
	LHL	MHL	HHL
Boiler A	60%	80%	85%
Boiler B	60%	80%	85%
CHP A	15%	40%	80%
CHP B	10%	40%	80%
CHP C	15%	40%	80%
CHP D	15%	40%	80%
CHP E	10%	40%	80%
CHP F	20%	50%	80%
CHP G	20%	50%	80%
CHP H	20%	60%	80%
CHP I	20%	50%	80%
CHP J	20%	40%	60%

It is important to note that the RHI tariffs presented here assume ongoing support for AD CHP through a Renewable Electricity Support Scheme (i.e. the successor to REFIT 3), in addition to the RHI tariffs given here. For the purposes of this analysis, we assume an indicative, flat level of support for renewable electricity of AD CHP of 14 c/kWh electricity exported in 2016, approximately in line with the level offered through REFIT 3. The support level is projected forward according to the same procedure as for the electricity retail prices as described in the *Economic analysis for an RHI for Ireland* report; however, we assume that the Renewable Electricity Support Scheme support level received by any given AD CHP installation remains fixed in real terms over the installation lifetime, even if the support level offered to new installations changes over time. The electricity exported is assumed to be 100% of the electricity produced.

In addition, it is assumed that the heat to the digester is an eligible heat use, such that this is included in the estimates of the on-site heat load. We note that, in the UK RHI scheme, heat used in the pasteurisation and drying of the digestate has not qualified for RHI payment to date[3]; and that it is proposed in the recent consultation document on reforms to the UK RHI that this position is retained and that there will be no RHI payments for heat input to the digester in the future[4]. Within Ireland, the definition of high efficiency CHP allows for heat used in the AD process itself to be counted as 'useful' heat provided it can be demonstrated that it is economically justifiable[5]. The definition of eligible heat uses in general, and in the particular case of AD, will be an important consideration. In the case

[3] Ofgem, *Non-domestic Renewable Heat Incentive (RHI) Guidance Volume One: Eligibility and How to Apply (Version 8)* (November 2016)
[4] Department of Energy and Climate Change, *The Renewable Heat Incentive: A reformed and refocused scheme: Proposed reforms to the existing Domestic and Non-Domestic Renewable Heat Incentive schemes*, URN: 16D/012 (March 2016)
[5] Commission for Energy Regulation. Certification Process for High Efficiency CHP Decision Paper (CER/12/125) (March 2012)

that heat input to the digester was not deemed eligible, somewhat higher levels of support than those presented here would likely be required.

In order to align the AD and biomethane tariff calculation methodology with the other technologies considered in this assessment, the metering, additional and hidden costs were set as for the other technologies.

The RHI tariffs required for each archetype for each set of design options were then determined. Table 3 to Table 5 present the tariffs for Scenario 2 (see the *Economic analysis for an RHI for Ireland* report). It can be seen that a wide range of tariffs is required to incentivise the range of archetypes, reflecting the variation in cost-effectiveness across different feedstock types, heat load levels and installation sizes, and whether the plant is entirely new or whether part of the required infrastructure already exists.

Table 3: AD boiler tariffs by system design (Scenario 2)

System ID	Feedstock	Capacity, kWth	Heat load	Heat output, MWh/yr	Tariff required, c/kWh
Boiler A	Farm - slurry and waste	48	Low	200	4.23
			Medium	267	3.16
			High	284	2.60
Boiler B	Waste – mixture of waste material	1,285	Low	4,888	0.00
			Medium	6,517	0.00
			High	6,925	0.00

Table 4: AD CHP tariffs by system design (Scenario 2)

System ID	Feedstock	Capacity, kWth	Heat load	Heat output, MWh/yr	Tariff, c/kWh
CHP A	Farm – slurry	100	Low	122	202.56
			Medium	326	72.78
			High	652	33.22
CHP B	Farm – slurry and silage	100	Low	81	33.93
			Medium	326	4.25
			High	652	0.00
CHP C	Farm – slurry	196	Low	256	19.01
			Medium	683	3.16
			High	1,365	0.00
CHP D	Farm – slurry and silage	512	Low	740	32.24
			Medium	1,972	8.13
			High	3,945	1.79
CHP E	Farm – silage and slurry	500	Low	407	147.21
			Medium	1,629	32.05
			High	3,259	13.75
CHP F	Farm – source-separated food waste, agri-food waste and grass silage	527	Low	1,079	59.42
			Medium	2,697	20.86
			High	4,315	10.99
CHP G	Farm – livestock manure, food waste and food process wastes	500	Low	880	0.00
			Medium	2,200	0.00
			High	3,519	0.00
CHP H	Waste – mixture of waste materials	500	Low	821	0.00
			Medium	2,464	0.00
			High	3,285	0.00
CHP I	Farm & Waste Fed – grass, slurry and food waste or sludges from industrial source	1,500	Low	2,444	19.12
			Medium	6,110	4.74
			High	9,776	0.92
CHP J	Waste Fed – all food waste	3,000	Low	4,888	0.00
			Medium	9,776	0.00
			High	14,664	0.00

Table 5: Biomethane tariffs by system design (Scenario 2)

System ID	Feedstock	Comments	Capacity, kW biogas	Biomethane produced, MWh/yr	Tariff required, c/kWh
BM A	Farm - silage (60%) and slurry (40%)	Biogas from several individual AD plant (five assumed) is transported by low pressure pipeline to a centralised upgrading and injection point	1,115	9,084	5.54
BM B	Waste Fed - MSW food waste	Plant capable of taking contained source separated food waste from MSW and commercial waste collections	1,746	14,529	6.75
BM C	Waste Fed - MSW food waste	Plant capable of taking contained source separated food waste from MSW and commercial waste collections	6,199	50,502	0.42
BM D	Waste Fed - food processing wastes	Plant taking less contaminated food wastes, typically with higher biogas yields	6,265	51,039	1.40
BM E	Farm - maize and food waste	Farm-based plants taking energy crops and waste	6,747	54,966	6.23
BM F	Farm - silage and slurry	Farm-based plant based on silage and slurry	6,341	51,655	2.59
BM G	Farm - silage and slurry	Similar plant to BM F but biomethane is compressed and taken by road to a central injection point	6,341	51,655	3.17
BM H	Wastewater treatment primary sludge	Existing wastewater treatment plant; only costs included are those for upgrading to biomethane and injection	4,385	35,727	0.00

As for all the other renewable heating technologies studied, tiered tariffs[6] for AD CHP, AD boilers and biomethane are based on the tariff required for a reference installation[7] of the appropriate technology and size.

[6] Here, a tiered tariff refers to a structure whereby the tariff (in the form of cents/kWh) reduces as the heat output from the installation increases. The tariffs are paid on a marginal basis, such that an increase in the heat output always results in an increase in the overall payment.

[7] The reference installations are the theoretical/modelled installations intended to be representative of each of the technology and tier segments defined in the RHI tariff structure. For example, as shown in Table 6, the tariff for the technology and tier segment corresponding to AD boilers with annual heat output ≤2,400 MWh/yr is based on the tariff calculated for the reference installation defined by 'Boiler A – MHL'.

The range of archetypes studied for AD CHP, boiler and biomethane grid injection have widely differing levels of deployment potential, due to the availability of feedstock and, in the case of BM H, the number of existing wastewater treatment plant. Furthermore, the low cost-effectiveness of some of the archetypes, and the associated high required tariffs, means it is unlikely to be desirable to design the tariffs to incentivise those types of plant. In comparison with tariffs derived for other renewable heating technologies in the *Economic analysis for an RHI for Ireland* study, AD CHP archetypes with required tariffs (in Scenario 2) greater than approximately 15 c/kWh can be seen to be relatively cost-ineffective. This applies to almost all of the low heat load AD CHP installations along with some of the slurry- and silage-based AD CHP installations.

As such, we have, in collaboration with Ricardo Energy & Environment, identified the reference installations corresponding to the types of AD and biomethane plant the RHI could be designed to incentivise, balancing the requirement for cost-effectiveness against the desire to ensure sufficient uptake of AD technologies, as described below. However, we have presented here the required tariffs for each of the individual archetypes (for Scenario 2) in order to demonstrate the tariff levels that would be required to incentivise additional types of plant to be deployed (by setting higher tariffs) or to further constrain the types of plant incentivised (by setting lower tariffs). For example, if there is a desire to incentivise the use of higher cost feedstocks in order to utilise a particular resource, such as grass silage, the tariffs would need to be increased accordingly.

Using the individual tariffs and based on stakeholder feedback, reference installations were selected as described below.

2.2.1 AD boiler: reference installation selection and tariff tiering

The low heat load installations are excluded as reference installations, as it is not deemed desirable to incentivise these due to the inefficient use of the heat generated. Instead, installations where a higher fraction of heat is used on-site should be incentivised. However, it is expected that situations with a high heat load will be limited. Therefore, installations with medium heat loads are deemed to be the most likely desirable outcome, and the reference installations are selected from the 'MHL' installations.

The key reason for the difference in cost between Boiler A and Boiler B is the different feedstock, rather than the different size. The waste-fed system would expect to receive a gate fee, whereas the system fed by farm slurry and waste (generated on farm) mixture would not. However, Boiler A is also representative of the smaller installations which could be expected in Ireland. The tier threshold for Tier 1 is therefore based on Boiler A, but with sufficient 'headroom' to incentivise a somewhat larger installation of this type within this tier.

Taking the reference installation and tiering considerations together, the following tiers and reference installations were selected for AD boilers. These are set out in full in Table 6.

- Tier 1 (0-2.4 GWh): Boiler A with MHL is the representative case at this scale. The threshold is selected based on a maximum expected capacity of ~200 kW.
- Tier 2 (>2.4 GWh): Boiler B with MHL is representative of larger installations. No tariff required is required for this archetype in Scenario 2, so no further payment is required within this tier.

2.2.2 AD CHP: reference installation selection and tariff tiering

We emphasise here that the analysis for AD CHP already includes a tariff from the Renewable Electricity Support Scheme for electricity generated (of 14 c/kWh in the base year 2016). The tariffs derived here for the RHI are those we find are required in addition to the renewable electricity support.

Archetypes that are mainly waste-fed, including some mixture of waste with slurry (CHP G, CHP H and CHP J) are found to be the lowest cost (due primarily to the gate fee received for the waste), with no RHI tariff required beyond the renewable electricity support. However, slurry- and silage-based systems (CHP A, CHP B, CHP C, CHP D, CHP E and CHP F) are included to understand the cost of maximising use of slurry and silage resource for AD CHP. These are generally higher cost, as shown in Table 4. In comparison with tariffs derived for other renewable heating technologies, AD CHP archetypes with required tariffs (in Scenario 2) greater than approximately 15 c/kWh can be seen to be relatively cost-ineffective.

It is expected that the farm-based installations would rarely achieve the high heat load level (HHL) so, as for AD boilers, the medium heat load (MHL) is generally taken as the more appropriate benchmark.

Taking these points together the following tiers and reference installations were selected for AD CHP:

- Tier 1 (0-2.4 GWh): Archetype CHP D with MHL is deemed the highest cost type of system at this scale that it would be desirable to incentivise, to ensure a significant fraction of the silage and slurry (i.e. non-waste) potential can be taken up. As such, this is selected as the reference installation for this tier. Archetypes CHP A and CHP E with MHL are deemed too high cost to be desirable to incentivise. Archetypes CHP B and CHP C are lower cost than CHP D, and so will be incentivised by the tariff derived. The threshold for this tier is based on allowing a small amount of headroom for the appropriate system types.
- Tier 2 (2.4-7.2 GWh): Archetype CHP I with MHL is deemed the highest cost system desirable to incentivise at this larger scale, as archetype CHP F with MHL is deemed too high cost. Archetypes CHP G, CHP H and CHP J require no tariff beyond the renewable electricity support. Again, the threshold is set to allow a small amount of headroom.
- Tier 3 (>7.2 GWh): Only archetype CHP I with HHL is deemed desirable at this scale for same reasons as given in Tier 2. For archetype CHP I no tariff is required beyond the payment for Tiers 1-2.

2.2.3 Biomethane: reference installation selection and tariff tiering

Archetype BM H is the special case of an existing wastewater sludge plant, for which it would be significantly more cost-effective to retrofit to enable biomethane grid injection compared with the other archetypes studied here. However, this would be limited to existing wastewater sludge plants and as such has limited potential. Therefore, this archetype is not deemed appropriate as a reference installation as it is proposed that the RHI should incentivise a wider range of plant types to contribute to renewable heating targets.

Archetype BM E is of low relevance due to the very limited availability of maize feedstock within Ireland and as such is not appropriate as a reference installation. Waste-fed systems (archetypes BM B, BM C and BM D) tend to have lower costs than silage- and slurry-fed systems of a similar size, mainly due to the difference in resource cost, as waste-fed systems would expect to receive gate fees. However, the resource potential of MSW food waste and food processing waste is relatively limited compared with the resource of silage and slurry, and stakeholder feedback suggests that the RHI should be designed to incentivise some level of uptake of this resource (i.e. archetype BM F or BM G).

There are some economies of scale in the biogas to biomethane upgrading step, which accounts for some of the differences in cost-effectiveness with installation size (such as between archetypes BM B and BM C). This suggests that some degree of tiering is appropriate. We note that archetype BM A represents a case where the biogas output of several (here it is assumed five) small AD plants would be delivered to a central grid injection point, so for the purposes of the tariff tiering the annual biomethane capacity of this archetype should be treated as the output of five of the individual AD plants (54.5 GWh rather than 10.9 GWh). Stakeholder feedback suggests that there will not be many biomethane plants larger than the archetypes shown here, in the case of Ireland (due mainly to the typical size of the agricultural facilities supplying slurry and silage, and in the case of food wastes, to the relatively small number of large urban conglomerations where sufficient quantities of food waste are available within a relatively small area[8]). However, to determine the thresholds for the tiers, some 'headroom' to account for some variation in the size of installations versus the sizing of archetypes is assumed here.

Taking the reference installation and tiering considerations together the following tiers and reference installations were selected for biomethane:

- Tier 1 (0-30 GWh/yr): Archetype BM B is selected as the reference installation as it is the only type representative of installations with an output of <30 MWh/yr (since BM A involves the delivery of the biogas output of five individual AD plant to a central injection point, as described above).
- Tier 2 (30-60 GWh): Archetype BM A is selected as the reference installation as it has the highest required tariff of the remaining archetypes deemed desirable to incentivise (once we have removed BM E for the reason above).
- Tier 3 (>60 GWh): Of the larger archetypes that are desirable to incentivise (including archetypes BM C, BM D and BM F) no further payment beyond the 60 MWh in Tiers 1 and 2 is required. Archetype BM F is selected as the reference installation as this requires the highest tariff of those deemed desirable to incentivise at this scale. However, we note that since this installation requires no further payment beyond tiers 1 and 2, the same results are seen when archetypes BM C or BM D are selected as the reference for tier 3).

[8] Feedstocks for AD typically have a high moisture content meaning that costs for transporting them are relatively high and AD plant typically seek to source feedstocks within a relatively small radius of the plant.

Table 6: AD boiler, AD CHP and biomethane tariff structure and reference installations

	Tier	Lower limit, MWh/yr	Upper limit, MWh/yr	Reference installation
Anaerobic digestion boiler	1	N/A	≤2,400	Boiler A - MHL
	2	>2,400	N/A	Boiler B - MHL
Anaerobic digestion CHP	1	N/A	≤2,400	CHP D - MHL
	2	>2,400	≤7,200	CHP I - MHL
	3	>7,200	N/A	CHP I - HHL
Biomethane grid injection	1	N/A	≤30,000	BM B
	2	>30,000	≤60,000	BM A
	3	>60,000	N/A	BM F

For each of the shortlisted scenarios, the tiered tariffs for AD boiler, AD CHP and biomethane were calculated following the design options as applied to derive the tariffs for the other technologies. However, these tariffs were not used to determine the uptake of these technologies in the BioHEAT model. Instead, the estimated deployment of AD and biomethane was determined by Ricardo Energy & Environment. This was done taking into consideration how fast the industry could develop in Ireland, based on estimates from stakeholders of number of plant per year which could be built in period to 2020 and thereafter, and experience from UK on the rate the industry expanded in response to introduction of support (taking account of differences in the final size of the market). The deployment scenarios are presented in Table 7. For all scenarios studied here, the uptake of AD and biomethane was taken as the Central deployment scenario. We note that, in reality, the uptake of AD and biomethane would (like all other technologies) depend on the level of the RHI tariffs offered along with tariffs offered for renewable electricity through the Renewable Electricity Support Scheme; however, this impact was not modelled here.

The heat production estimated in Table 7 assumes that all biomethane injected into the grid is used for heat production. However, it should be noted that under the Renewable Energy Directive, in accounting for the contribution of biomethane injected to the grid towards sectoral renewable energy targets for heat, electricity and transport, the quantity of biomethane must be divided between these three sectors in the proportions that natural gas use is divided between these sectors. About half (46%) of natural gas consumption in Ireland is estimated to be for heating[9]. Allocating only 46% of biomethane produced to the heat sector would reduce the total heat produced in the central deployment scenario to 79 GWh/yr and in the high deployment scenario to 91 GWh/yr.

[9] Based on data in 2015 Energy Balance, an estimated 46% of natural gas is used for heating. Assumes all final energy consumption of gas is used for heat, apart from that used in transport sector. Energy balance is available at http://www.seai.ie/Energy-Data-Portal/Energy-Balance/

Table 7: Deployment scenarios for AD CHP, AD boilers and biomethane grid injection in 2020

System ID	Low deployment			Central deployment			High deployment		
	LHL	MHL	HHL	LHL	MHL	HHL	LHL	MHL	HHL
Boiler A	-	-	2	-	-	3	-	-	3
Boiler B	-	1	-	-	-	1	-	-	1
CHP A	-	-	-	-	-	-	-	-	-
CHP B	-	-	2	-	-	2	-	-	1
CHP C	-	-	1	-	-	1	-	-	1
CHP D	-	-	1	-	-	1	-	-	1
CHP E	-	-	-	-	-	-	-	-	-
CHP F	-	-	-	-	-	-	-	-	-
CHP G	-	-	2	-	-	4	-	-	4
CHP H	-	-	2	-	-	4	-	-	4
CHP I	-	1	-	-	-	1	-	-	1
CHP J	-	-	1	-	-	1	-	-	-
BM A	-			-			-		
BM B	-			-			1		
BM C	-			-			-		
BM D	-			-			1		
BM E	-			-			-		
BM F	-			-			-		
BM G	-			-			-		
BM H	-			1			1		
Number of plants	**13**			**19**			**19**		
Total heat, GWh/yr	**47**			**96**			**140**		

3 Funding support for biomethane through a levy on gas consumers

Biomethane production could be supported by payments to the producer of the biomethane (as in the UK RHI) or by payments to the final user of the biomethane. As part of the *Interface* study, SEAI asked Ricardo Energy & Environment to evaluate the advantages and disadvantage of these two approaches. This work, which also examined what approach has been used in other countries that support biomethane and which approach stakeholders would prefer, is reported in full in Appendix A. It concluded that both approaches have been used in other countries, and that both of the approaches had some advantages and disadvantages, although mechanisms could be put in place to overcome some of the issues identified. It found that stakeholders in Ireland would generally prefer payments directly to the operator injecting biomethane to the grid (which would typically be the biomethane producer).

The *Interface* study also required Ricardo Energy & Environment to examine whether support for biomethane could be funded through a levy on gas consumers and Element Energy to complete a preliminary analysis of this option. The work by Ricardo Energy & Environment, which examines the legislative and operational feasibility of such an approach and whether other countries have used this approach to fund support (rather than exchequer funding), is reported in full in Appendix B. In the form studied here, biomethane producers would be supported through the RHI, and the RHI payment required would be raised (on an annual basis) through a levy on certain gas consumers. The levy is assumed to be fixed in c/kWh terms for each year, but to vary year to year according to the amount that needs to be raised.

The objective of this preliminary analysis is to understand the likely size of the levy under a range of scenarios for (i) the deployment level of biomethane and (ii) the design of the RHI and, accordingly, the tariff offered to biomethane producers.

3.1 Approach

The annual RHI payment required to support biomethane is determined for three biomethane deployment scenarios (Low, Central and High deployment), using the tariffs derived in three representative RHI design scenarios taken from the *Economic analysis for an RHI for Ireland* report. The annual payment required is then combined with the expected annual gas consumption across the eligible sectors (see below) to calculate the annual gas levy required (on a c/kWh basis) over the duration of the scheme.

3.1.1 Applicability of the gas levy

In this analysis, according to guidance from SEAI and DCCAE, we make the following assumptions regarding the applicability of the gas levy:

- Gas levy applies to public, commercial and industrial gas consumers;
- Residential gas consumers, and the use of gas to generate electricity, are exempt from the levy.

3.1.2 Biomethane RHI tariffs and support period

The tariffs for biomethane and the duration of support are based on our analysis presented in the *Economic analysis for an RHI for Ireland* report, which includes a range of design options for the RHI, and hence a range of tariffs for biomethane. For the analysis of the gas levy funding mechanism, the results are presented for the three RHI design scenarios listed in Table 8.

In addition, two cases for the period of eligibility for RHI support for biomethane are assessed: in case (i) the RHI supports new biomethane plant installed over the period 2018–2020 and in case (ii) the RHI supports new biomethane plant installed over the period 2018–2025.

For all scenarios the RHI payments required are determined using the tariffs tiered by annual biomethane output taken from the *Economic analysis for an RHI for Ireland* report, as shown in Table 9. The duration of support in each case is 15 years and the tariffs are constant over the support period.

Table 8: RHI design scenarios included in gas levy analysis

RHI design scenario	Scenario name
2	Default design options
5	Tariffs capped at biomass boiler tariffs
8	Higher IRR (12%)

Table 9: Biomethane tariffs in the three RHI design scenarios

RHI design scenario	Tier	Lower limit, MWh/yr	Upper limit, MWh/yr	Tariff, c/kWh
2	1	N/A	≤30,000	6.75
	2	>30,000	≤60,000	4.04
	3	>60,000	N/A	0.00
5	1	N/A	≤300	6.75
	2	>300	≤1,000	5.56
	3	>1,000	≤3,000	2.37
	4	>3,000	≤10,000	2.25
	5	>10,000	≤30,000	1.67
	6	>30,000	≤60,000	1.67
	7	>60,000	N/A	0.00
8	1	N/A	≤30,000	9.06
	2	>30,000	≤60,000	2.43
	3	>60,000	N/A	0.00

3.1.3 Deployment scenarios for biomethane

The three scenarios for deployment of biomethane to 2025 were developed by Ricardo Energy & Environment, based on stakeholder consultation and their own analysis. The deployment is disaggregated across the biomethane archetypes, for which individual RHI tariffs have been calculated, as shown above in Table 5. The three deployment scenarios (Low, Central and High) are summarised in Table 10 to Table 12. Here, it is assumed that no further deployment will occur once the period of eligibility for RHI support ends (either in 2020 or 2025 depending on the case in question).

Table 10: Low deployment scenario for biomethane (cumulative uptake by archetype)[10]

System ID	2018	2019	2020	2021	2022	2023	2024	2025
BM A	-	-	-	-	-	-	-	5
BM B	-	-	-	-	-	1	1	1
BM C	-	-	-	-	-	-	-	-
BM D	-	-	-	-	-	-	-	-
BM E	-	-	-	-	-	-	-	-
BM F	-	-	-	-	-	-	-	-
BM G	-	-	-	-	-	-	-	-
BM H	-	-	-	-	-	-	-	-
Total number of plants	**-**	**-**	**-**	**-**	**-**	**1**	**1**	**6**
Total biomethane, GWh/yr	**0**	**0**	**0**	**0**	**0**	**15**	**15**	**60**

Table 11: Central deployment scenario for biomethane (cumulative uptake by archetype)[10]

System ID	2018	2019	2020	2021	2022	2023	2024	2025
BM A	-	-	-	-	-	-	-	5
BM B	-	-	-	-	1	1	2	2
BM C	-	-	-	-	-	-	-	-
BM D	-	-	-	-	-	-	-	-
BM E	-	-	-	-	-	-	-	-
BM F	-	-	-	-	-	1	1	1
BM G	-	-	-	-	-	-	-	-
BM H	-	-	1	1	1	1	1	1
Total number of plants	**-**	**-**	**1**	**1**	**2**	**3**	**4**	**9**
Total biomethane, GWh/yr	**0**	**0**	**36**	**36**	**50**	**102**	**116**	**162**

Table 12: High deployment scenario for biomethane (cumulative uptake by archetype)[10]

System ID	2018	2019	2020	2021	2022	2023	2024	2025
BM A	-	-	-	-	-	5	5	10
BM B	-	-	1	1	2	2	3	3
BM C	-	-	-	-	-	-	-	-
BM D	-	-	1	1	1	1	1	1
BM E	-	-	-	-	-	-	-	-
BM F	-	-	-	-	-	1	1	1
BM G	-	-	-	-	-	-	-	-
BM H	-	-	1	1	2	2	2	2
Total number of plants	**-**	**-**	**3**	**-**	**5**	**11**	**12**	**17**
Total biomethane, GWh/yr	**0**	**0**	**101**	**101**	**152**	**249**	**263**	**309**

[10] Note: No further deployment is expected once the period of eligibility for RHI support ends. Therefore, the deployment shown for 2021-2025 is only expected to occur if the RHI scheme remains open to new applicants beyond 2020.

3.1.4 Gas consumption across applicable sectors

The gas consumption on which the levy is to be applied, over the period 2020 to 2035 or 2040 (depending on the period of eligibility for support) is based on SEAI's Energy Forecasts, using the 'NEEAP/NREAP' scenario. This scenario assumes that Ireland's National Energy Efficiency Action Plan (NEEAP) and National Renewable Energy Action Plan (NREAP) strategies to 2020 are met, but that no further policies are implemented after that. It may therefore be expected, given the ongoing drive for energy efficiency and decarbonisation beyond 2020, that this scenario provides an upper bound to the gas consumption. A lower gas consumption, for the same level of support for biomethane, would translate into a higher gas levy according to a simple reciprocal relationship; for example, a 20% lower gas consumption across the applicable sectors would lead to a 25% increase[11] in the gas levy in cents/kWh terms.

The proportion of the annual gas demand in all sectors, excluding gas used for electricity generation but including residential gas demand (even though the levy is not applied to the residential sector), which is provided by biomethane is given in Table 13 for each deployment scenario.

Table 13: Proportion of annual gas demand provided by Biomethane (excluding gas used for electricity generation)

Year	Period of eligibility for RHI support 2018–2020			Period of eligibility for RHI support 2018–2025		
	Low	Central	High	Low	Central	High
2018	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2019	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2020	0.0%	0.2%	0.6%	0.0%	0.2%	0.6%
2021	0.0%	0.2%	0.6%	0.0%	0.2%	0.6%
2022	0.0%	0.2%	0.6%	0.0%	0.3%	0.9%
2023	0.0%	0.2%	0.6%	0.1%	0.6%	1.4%
2024	0.0%	0.2%	0.6%	0.1%	0.7%	1.5%
2025	0.0%	0.2%	0.6%	0.3%	0.9%	1.8%
2026	0.0%	0.2%	0.6%	0.3%	0.9%	1.8%
2027	0.0%	0.2%	0.6%	0.3%	0.9%	1.8%
2028	0.0%	0.2%	0.6%	0.3%	0.9%	1.8%
2029	0.0%	0.2%	0.6%	0.3%	0.9%	1.8%
2030	0.0%	0.2%	0.6%	0.3%	0.9%	1.8%
2031	0.0%	0.2%	0.6%	0.3%	0.9%	1.8%
2032	0.0%	0.2%	0.6%	0.3%	0.9%	1.7%
2033	0.0%	0.2%	0.6%	0.3%	0.9%	1.7%
2034	0.0%	0.2%	0.6%	0.3%	0.9%	1.7%
2035	0.0%	0.0%	0.0%	0.3%	0.7%	1.2%
2036	0.0%	0.0%	0.0%	0.3%	0.7%	1.2%
2037	0.0%	0.0%	0.0%	0.3%	0.6%	0.9%
2038	0.0%	0.0%	0.0%	0.3%	0.3%	0.3%
2039	0.0%	0.0%	0.0%	0.3%	0.3%	0.3%
2040	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

[11] Since 1/(1 – 20%) = 125%

3.2 Results and discussion

The gas levy required during each year 2018–2040 has been derived for each combination of biomethane deployment scenario and RHI design scenario. As described above, this has been repeated for two cases: (i) for a period of eligibility for RHI support 2018–2020, and (ii) for a period of eligibility for RHI support 2018–2025. The results are shown for the case of eligibility to 2020 in Table 14, and for the case of eligibility to 2025 in Table 15. In the case studied here, biomethane producers would receive support for 15 years, such that plant coming online in 2020 will receive support until 2034 inclusive, and plant coming online 2025 will require support until 2039 inclusive.

For the period of eligibility for RHI support for biomethane of 2018–2020, the peak gas levy required ranges from 0.006 c/kWh for the Central biomethane deployment scenario in RHI design scenario 5 to 0.063 c/kWh for the High biomethane deployment scenario in RHI design scenario 8.

For the period of eligibility for RHI support of 2018–2025, the levy required increases after 2020 as the number of biomethane plants deployed increases. In this case, the gas levy increases to 0.032 c/kWh by 2025 for the Central biomethane deployment scenario in RHI design scenario 5, and to 0.214 c/kWh by 2025 for the High biomethane deployment scenario in RHI design scenario 8.

For many scenarios, the gas levy decreases at some point after the deployment of new biomethane plants ends (for example, after 2021 for the period of eligibility for RHI support for biomethane of 2018–2020, RHI design scenario 8 in the high deployment scenario) despite the plants receiving the same level of ongoing support. This is because whilst the RHI payments remain constant, the gas consumption in the applicable sectors increases, such that the fixed amount which needs to be raised is spread over a larger levy base each year.

For RHI design scenario 5, the tariff for each tier is the same or lower than in Scenario 2. This results in a lower annual RHI payment across the biomethane archetypes and hence requires a lower gas levy. In contrast, RHI design scenario 8 has higher tariffs than scenario 2 and therefore a higher levy is required. The gas levy required for the central biomethane deployment scenario, in RHI design scenario 2 and for the period of eligibility for RHI support of 2018–2020 is 0.020 c/kWh in 2025. This corresponds to ≈0.2% of the expected typical gas price for a small user in 2025 (8.7 c/kWh) and ≈0.5% of that for a large industrial user in 2025 (4.4 c/kWh). Under the high deployment scenario, in RHI design scenario 2 and for the period of eligibility for RHI support of 2018–2025, the gas levy required is 0.174 c/kWh in 2025, corresponding to 2.0% and 4.0% of the expected typical gas price for a small and a large industrial user respectively.

Table 14: Gas levy for period of eligibility for RHI support 2018–2020, c/kWh

Year	RHI design scenario								
	S2: Default design options			S5: Tariffs capped at biomass boiler tariffs			S8: Higher IRR (12%)		
	Biomethane deployment Scenario			Biomethane deployment Scenario			Biomethane deployment Scenario		
	Low	Central	High	Low	Central	High	Low	Central	High
2018	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.000	0.020	0.054	0.000	0.006	0.018	0.000	0.025	0.063
2021	0.000	0.020	0.054	0.000	0.006	0.018	0.000	0.025	0.063
2022	0.000	0.020	0.054	0.000	0.006	0.018	0.000	0.025	0.062
2023	0.000	0.020	0.054	0.000	0.006	0.018	0.000	0.025	0.062
2024	0.000	0.020	0.053	0.000	0.006	0.018	0.000	0.025	0.062
2025	0.000	0.020	0.053	0.000	0.006	0.018	0.000	0.025	0.062
2026	0.000	0.020	0.053	0.000	0.006	0.018	0.000	0.025	0.062
2027	0.000	0.020	0.053	0.000	0.006	0.018	0.000	0.025	0.062
2028	0.000	0.020	0.053	0.000	0.006	0.018	0.000	0.025	0.062
2029	0.000	0.020	0.053	0.000	0.006	0.018	0.000	0.025	0.062
2030	0.000	0.020	0.053	0.000	0.006	0.018	0.000	0.025	0.062
2031	0.000	0.020	0.053	0.000	0.006	0.018	0.000	0.025	0.062
2032	0.000	0.020	0.053	0.000	0.006	0.018	0.000	0.025	0.062
2033	0.000	0.020	0.053	0.000	0.006	0.018	0.000	0.025	0.062
2034	0.000	0.020	0.052	0.000	0.006	0.018	0.000	0.024	0.061
2035	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2036	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2038	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2039	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2040	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Table 15: Gas levy for period of eligibility for RHI support 2018–2025, c/kWh

Year	RHI design scenario								
	S2: Default design options			S5: Tariffs capped at biomass boiler tariffs			S8: Higher IRR (12%)		
	Biomethane deployment Scenario			Biomethane deployment Scenario			Biomethane deployment Scenario		
	Low	Central	High	Low	Central	High	Low	Central	High
2018	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.000	0.020	0.054	0.000	0.006	0.018	0.000	0.025	0.063
2021	0.000	0.020	0.054	0.000	0.006	0.018	0.000	0.025	0.063
2022	0.000	0.029	0.084	0.000	0.009	0.028	0.000	0.037	0.101
2023	0.009	0.054	0.137	0.003	0.018	0.048	0.012	0.062	0.164
2024	0.009	0.063	0.146	0.003	0.021	0.051	0.012	0.074	0.176
2025	0.036	0.090	0.174	0.014	0.032	0.062	0.049	0.111	0.214
2026	0.036	0.090	0.174	0.014	0.032	0.062	0.049	0.111	0.214
2027	0.036	0.090	0.174	0.014	0.032	0.062	0.049	0.111	0.214
2028	0.036	0.090	0.174	0.014	0.032	0.062	0.049	0.111	0.214
2029	0.036	0.090	0.174	0.014	0.032	0.062	0.049	0.111	0.214
2030	0.036	0.090	0.174	0.014	0.032	0.062	0.049	0.111	0.214
2031	0.036	0.090	0.174	0.014	0.032	0.062	0.049	0.111	0.213
2032	0.036	0.090	0.174	0.014	0.032	0.062	0.049	0.111	0.213
2033	0.036	0.090	0.174	0.014	0.032	0.062	0.049	0.111	0.213
2034	0.036	0.090	0.172	0.014	0.032	0.061	0.049	0.111	0.211
2035	0.036	0.070	0.118	0.014	0.026	0.043	0.049	0.086	0.149
2036	0.036	0.070	0.118	0.014	0.026	0.043	0.049	0.086	0.148
2037	0.036	0.061	0.088	0.014	0.023	0.033	0.049	0.074	0.111
2038	0.027	0.036	0.036	0.011	0.014	0.014	0.037	0.049	0.049
2039	0.027	0.027	0.027	0.011	0.011	0.011	0.037	0.037	0.037
2040	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

4 Preliminary assessment of an RHI tariff for BioLPG

An approximate estimate of the cost of supplying bio-liquefied petroleum gas (BioLPG) – in place of conventional LPG – was provided to Ricardo Energy & Environment by Calor (see Appendix B for more details). This dataset is summarised in Table 16.

It is important to note that these costs are based on the supply within Ireland of BioLPG imported in bulk from the existing BioLPG production plant in Rotterdam; that is, the costs do not relate to the production of BioLPG from a new plant in Ireland. As such, the tariff for BioLPG described here is not intended to incentivise the production of BioLPG in Ireland, but to encourage the supply and uptake of imported BioLPG within Ireland.

Calor reported that the 'premium' in the cost of supplying BioLPG versus conventional LPG, as presented in Table 16, is mainly associated with transport costs from Rotterdam (where the world's first BioLPG production facility operates[12]), as well as the administration and auditing costs for implementing a mass balance system for the BioLPG to allow tracking of imports and sales. This implies that the wholesale price of BioLPG in Rotterdam is therefore the same as the wholesale price of conventional LPG in Ireland.

Since the transport and administration of the BioLPG would be expected to be undertaken in bulk, the premium for BioLPG supply within Ireland is expected to be irrespective of the supply type (i.e. commercial cylinders or bulk supply) within Ireland. On this basis, it can be seen in Table 16 that, according to the cost dataset received, the premium for BioLPG versus conventional LPG is estimated to be 1.3 cents/kWh for each supply type.

Table 16: Conventional LPG and BioLPG cost data for 2016 (including carbon tax)

	Supply type	unit	€/unit	kWh/unit	€/kWh
Conventional LPG	Commercial cylinders	kg	1.741	13.96	0.125
	Bulk LPG (0 - 3 tonnes)	litre	0.551	7.09	0.078
	Bulk LPG (3.1 - 40 tonnes)	litre	0.463	7.09	0.065
BioLPG	Commercial cylinders	kg	1.923	13.96	0.138
	Bulk LPG (0 - 3 tonnes)	litre	0.644	7.09	0.091
	Bulk LPG (3.1 - 40 tonnes)	litre	0.556	7.09	0.078

The data above were used to develop an estimate of the tariff that would be required to support the supply of BioLPG through the RHI. It should be noted that the BioLPG tariffs calculated in this study are based on a single dataset and are therefore intended to be indicative only.

In contrast to the other RH technologies studied in the *Economic analysis for an RHI for Ireland*, the supply of BioLPG (at least, according to the form in which the cost data has been provided here) includes only a marginal 'ongoing' cost, with no fixed or upfront component. For this reason, we propose that the most appropriate approach may be to

[12] The bioLPG is a co-product from Neste's Hydrotreated Vegetable Oil (HVO) production facility. Feedstocks for HVO production are vegetable and waste oils, meaning that the bioLPG can be considered a renewable fuel.

apply an annually-varying tariff, with no fixed period of support (such as the 15 year duration of support applied in the central case for other RH technologies, where an upfront cost is incurred). As for all other RH technologies, the tariff would be equal to the difference in net present value of supplying BioLPG rather than conventional LPG; however, in this case this can be done on a purely marginal basis, since all costs are marginal (again, at least in the form in which they have been provided here). We note that this means that the tariff calculated for supply of BioLPG is independent of the discount rate applied.

Since it is currently uncertain whether BioLPG will be exempt from the carbon tax/price, the tariffs are determined both for the case where the carbon tax/price applies to BioLPG, and the case where BioLPG is exempt from the carbon tax/price. In order to do this, conventional LPG fuel prices were disaggregated into a component exclusive of the carbon tax/price, and a component representing the carbon tax/price. For this, we assumed a carbon intensity for LPG of 0.232 gCO_2/kWh, and a current level of carbon tax of €20 per tonne CO_2.

The carbon tax/price component was projected forward according to the larger of the current level of the carbon tax in Ireland (€20 per tonne) and the projected EU ETS carbon price (European Union Reference Scenario values), as summarised in Table 17.

The component exclusive of the carbon tax/price was projected forward according to the wholesale oil price in the UK Department of Energy and Climate Change's *Fossil fuel price projections*[13]. However, according to guidance from Ricardo Energy & Environment, the 'premium' for BioLPG (excluding any difference in the applicable carbon tax/price) is assumed to remain constant at 1.3 c/kWh.

The tariffs required are given in Table 18. Given the above, the tariff required remains constant over time at 1.3 c/kWh in the case where BioLPG is not exempt from the carbon tax/price. In the case where BioLPG is exempt from the carbon tax/price, the tariff required decreases as the carbon tax/price increases, which means that the price of conventional LPG increases and the price gap between the supply of conventional LPG and BioLPG reduces.

We note that, since the cost premium provided here for the supply of BioLPG versus conventional LPG is partly due to the cost of transport, and since transport costs would be expected to change over time, the tariff should be reviewed annually. In order to account for this in a robust way, the cost premium should be disaggregated into its transport, administration and other components – this disaggregation was not provided in the dataset used here. Furthermore, additional data should be sought beyond the single dataset presented in this analysis to support the final design of a tariff for BioLPG.

[13] Department of Energy and Climate Change, *Fossil fuel price projections: 2015* (November 2015)

Table 17: Carbon tax/price projections

Year	EU ETS Allowances (€2016 per tonne CO_2)[14]	Larger of current carbon tax of €20 per tonne and the EU ETS Allowance (€2016 per tonne CO_2)[15]
2016	9.8	20.0
2017	11.4	20.0
2018	13.0	20.0
2019	14.7	20.0
2020	16.3	20.0
2021	17.9	20.0
2022	19.5	20.0
2023	21.2	21.2
2024	22.8	22.8
2025	24.4	24.4
2026	26.8	26.8
2027	29.2	29.2
2028	31.6	31.6
2029	34.0	34.0
2030	36.4	36.4
2031	38.2	38.2
2032	40.0	40.0
2033	41.9	41.9
2034	43.7	43.7
2035	45.6	45.6

[14] European Union Reference Scenario values
[15] www.revenue.ie (Accessed December 2016)

Table 18: BioLPG tariffs, c/kWh

Year	Tariffs, c/kWh	
	BioLPG not exempt from carbon tax/price	BioLPG exempt from carbon tax/price
2016	1.3	0.9
2017	1.3	0.9
2018	1.3	0.9
2019	1.3	0.9
2020	1.3	0.9
2021	1.3	0.9
2022	1.3	0.9
2023	1.3	0.8
2024	1.3	0.8
2025	1.3	0.7
2026	1.3	0.7
2027	1.3	0.6
2028	1.3	0.6
2029	1.3	0.5
2030	1.3	0.5
2031	1.3	0.4
2032	1.3	0.4
2033	1.3	0.3
2034	1.3	0.3
2035	1.3	0.3

Appendix A

Report on Options for Biomethane Support

by Ricardo Energy & Environment

1 Introduction

1.1 Background

Ricardo Energy & Environment are currently carrying out an economic assessment of the costs and benefits of biogas and biomethane in Ireland for Working Group 2 of the draft bioenergy plan. Element Energy are currently carrying out a study for the Department of Communications, Climate Action and Environment (DCCAE) to undertake an economic analysis and evaluate the economic impacts of a Renewable Heat Incentive (RHI) for Ireland. The RHI study considered biogas CHP, but not the upgrading of biogas into biomethane and its injection into the grid. In order to ensure a full and robust assessment of the viability and cost-effectiveness of supporting biogas and biomethane under the RHI and the associated optimal design of such an RHI tariff, SEAI have commissioned an 'interface' piece of work, carried out jointly by Ricardo Energy & Environment and Element Energy to ensure that all appropriate information is available to consider potential support for biomethane under an RHI alongside other renewable heat technologies.

This short report from Ricardo Energy & Environment sets out the findings from Task 1 of the interface study 'Options for biomethane and biopropane payments under the RHI'. It provides an overview and analysis of the options available for supporting Biomethane-to-Grid (BtG) under the RHI, and discusses the advantages and disadvantages of offering payment to the biomethane producer, versus the biomethane end user.

1.2 Biomethane and Renewable Energy Targets

Biomethane can be produced by upgrading the biogas produced from anaerobic digestion plant; this involves removing the CO_2 and other impurities in the biogas. The biomethane produced can then be injected into the natural gas grid, either directly, or by transporting it by road to a centralised injection point. Once in the grid, it is delivered along with the natural gas to all natural gas consumers who may use it to generate heat and/or electricity or compress it and use it as a vehicle fuel. It is also possible to use the biomethane directly as a vehicle fuel without using the gas grid, by locating a biomethane filling station at the same site as the AD plant producing the biomethane, or transporting the biomethane directly by road to a filling station.

As a renewable resource, biomethane can count towards Ireland's renewable energy targets under the Renewable Energy Directive (RED)[16]; Ireland has an overall renewables target under the RED for 16% of total final energy consumption to come from renewable energy in 2020, and a binding target of 10% renewable energy in transport. There are also individual national targets for 2020 of contributions from renewable energy in electricity (RES-E) and renewable energy for heat and cooling (RES-H), which are 40% and 12% respectively. As biomethane can be used in each of these sectors, it can potentially contribute to each of these targets. When the biomethane is injected into the grid, then the RED stipulates that its contribution must be allocated between these three sectoral targets in the same proportions as natural gas use. So for example in Ireland, about 46% of natural gas is used for heat[17], so therefore 46% of any biomethane injected into the grid can be assumed to be used in the production of heat, and the heat produced from that quantity of biomethane can be counted against the RES-H target. Where biomethane is used as a vehicle fuel without being transported in the natural gas grid, then all of that biomethane can be counted against the RES-T target.

[16] Renewable Energy Directive (009/28/EC)
[17] Based on data in 2015 Energy Balance. Assumes all final energy consumption of gas is used for heat, apart from that used in transport sector. Energy balance is available at http://www.seai.ie/Energy-Data-Portal/Energy-Balance/

This approach is however being challenged by some countries. Italy, who have a relatively high use of natural gas in the transport sector, and wish to use biomethane as way of meeting their 10% RED target for the transport sector are setting up a biomethane monitoring mechanism to allow the correct allocation of biomethane to the correct sector of use without any proportional allocation. All transport fuel distributors signing long–term contracts with biomethane producers will be required to register their contracts into a specific centralised database managed by the Italian state owned Renewable Energy Agency (GSE). Contracts for withdrawals from the grid will also be registered in the database, allowing the quantity of biomethane going to the transport sector to be calculated[18].

At present it is not clear that the European Commission will allow tracking schemes such as the one being set up in Italy to be used to specifically allocate biomethane use to particular sectors based on the end use of the biomethane. If the accounting rules under RED were changed by the EC to permit the allocation of biomethane to specific end use sectors using information from such tracking systems, it is possible that a similar system could be developed to monitor the flow of biomethane in to the grid and its final end use in Ireland (e.g. if the Green Gas Certification Scheme discussed in Section 4 was implemented). In that case, biomethane could be allocated to specific sectoral RES targets on a tracked basis, rather than using proportional allocation. The implications that such a change could have in the relative advantages and disadvantages of different types of support mechanisms is considered in the relevant sections of the report.

1.3 Support for biomethane

Under current market conditions, biomethane cannot compete against natural gas on price alone. As a result, several support schemes have been developed across Europe, which have led to the rapid deployment of biomethane plants in several European countries. These schemes vary in type, with some supporting the production of biomethane directly and others supporting the production of renewable electricity produced from biomethane injected to the grid. Full details are given in Section 2.

Key stakeholders in the biogas and biomethane area were asked as part of the wider stakeholder consultation carried out by Ricardo Energy & Environment on their economic assessment study, for their views on the most appropriate financial mechanisms for supporting BtG. These are summarised in Section 3. Based on the review from Section 2 and 3, Section 4 provides a summary of the available options, their pros and cons and makes recommendation regarding the most appropriate option for supporting BtG under the RHI. Section 5 considers bioLPG.

1.4 Options for supporting BtG

The key players involved in the biomethane supply chain are;

- The biomethane **Producer** (which could also be the biogas producer and owner of the AD / biogas upgrade plant),

[18] Perrella G and D'Innocenzo W, Ministry of Economic Development. 'The potential role of biomethane in Italian transport', presentation to the IEA Bioenergy ExCo77 workshop, Rome, 17 May 2016.

- The Gas **Transporter**; this is the company which owns / operates the gas pipeline and so needs to ensure that the biomethane injected is compliant with national requirements,
- The Gas **Shipper** who contracts with the gas transporter to deliver gas through the gas pipeline and a contract with the producer to buy the biomethane from them. A gas shipper must have a license before they are able to take part in any shipping action.
- The **Supplier**; this is the company which buys gas from shipper and sells it to the end-user (as 'green gas'),
- The **End-user** of the biomethane; e.g. a CHP plant or any user which would normally use natural gas from the grid

Biomethane can be incentivised either by providing support directly to the producer of biomethane or to one of the key players down the supply chain e.g. the gas supplier or gas end users. Potential options under these two broad approaches - support to end user or support to producer include:

- **Approach 1: Incentivisation at the end-user / demand side:**
    - Payments to the end user for either each unit of renewable gas consumed or used or per unit of renewable electricity and/or heat produced from renewable gas used,
    - Investment support (for example, capital grants for investment in CHP running on biomethane),
    - Tax relief on fuel or electricity for sites using biomethane,
    - Revenues from emission trade where the product of the end-user receives Emissions Trading Scheme (ETS) allowances for burning the biomethane. The end user is exempt from reporting the CO_2 resulting from biomethane combustion.

- **Approach 2: Incentivisation at the supply / biomethane production side**:
    - Support as feed-in-tariff (FiT) payments to the producer on the biomethane injected into the grid
    - Direct investment support: providing capital grants for developing the plant or provision of loans at reduced interest rates,
    - Cost sharing for grid connection,
    - Cost sharing for biomethane upgrading facilities

The features, requirements for implementation as well as pros and cons of these two approaches are discussed in detail in Section 4.

In addition to the financial incentives listed above, further non-financial measures can be used to encourage the deployment of BtG plants and to ensure reduction of the risk associated with developing such projects. These include:

- Priority access for biomethane plants to the public grid,
- Standardisation and providing clear guidelines on planning permits, licensing procedures and requirements and on the local authority permitting process to avoid project delay,
- Facilitating the process of obtaining grid-connection by ensuring that there is a clear institutional framework, with clearly defined roles, rights and responsibilities. This could be achieved by setting up a supervisory governmental agency, or expanding the role of existing bodies.

Non-financial barriers to the deployment of biomethane are being considered further in the main economic assessment study on biogas and biomethane.

2 Experience from Other Countries

Several countries have already developed financial mechanisms for supporting the development of BtG projects. The applied mechanisms differ from one country to another and come into action at different parts of the BtG supply chain. A summary of experiences from other countries where the AD industry is relatively well developed or is expanding rapidly, including descriptions of support mechanisms and sources of financing are given in Table 1 below.

Currently, the UK, the Netherlands and France have introduced feed-in-tariffs (FiTs) for biomethane injection into the gas network making the production of biomethane economically feasible. In the UK, the RHI was created to support renewable heat technologies, including biomethane, which when injected into grid receives an RHI tariff. At the beginning of the scheme, this was a flat rate of 9.5 c/kWh of biomethane (7.71 p/kWh[19]), but in 2014 a tiering scheme was introduced with quantities of biomethane injected over 40,000 kWh receiving a lower payment of 5.6 c/kWh (4.2 p/kWh) and biomethane quantities over 80,000 GWh per year receiving 4.3 c/kWh (3.49 c/kWh). These rates have subsequently been substantially digressed and payments for installations accredited after 1st October 2016 are now 5.3 c/kWh (4.32 p/kWh), 3.1 c/kWh (2.54 p/kWh) and 2.4 c/kWh (1.96 p/kWh).

In France, the biomethane FiT is dependent on the size of the biomethane plant (i.e. production capacity) and on the category of feedstock used. The rate is currently 6.9 to 12.5 c/kWh for anaerobic digestion plants. Support under the Netherlands SDE+ support scheme are 6 c/kWh, and with higher rates of 6.4 to 10.6 c/kWh for anaerobic digestion plants using manures as a feedstock.

In Germany and Austria, support is provided at the end of the supply chain where payments are provided to operators using biomethane for generating electricity in CHP plants. Sweden and the Netherlands provide support to the use of biomethane in the transport sector. Most countries provide additional benefits on top of the FiT on gas or electricity. These include investment support and tax relief on fuel and electricity.

[19] All payments have been converted using the average exchange rate for 2016 (to October 2016) of £0.811 per euro, based on monthly average exchange rate tables from Central Bank of Ireland available at https://www.centralbank.ie/polstats/stats/exrates/Pages/default.aspx

Table 1: Country review of BtG support mechanisms

Country	Financing mechanism	Source of Finance
United Kingdom	• Biomethane producer support. The approach of payment made to the producer rather than the end-user was decided early on in Energy Act 2008[20], before the creation of the RHI. • Support in the form of FiT on the biomethane injected into the grid is provided directly to the biomethane producer (through the UK Renewable Heat Incentive, RHI), • This is paid on top of the natural gas price and is guaranteed for 20 years, • The RHI also supports biogas consumption through payments on the amount of heat generated, with payments also grandfathered for 20 years, • Investment support is also provided by the Department for Environment, Food and Rural Affairs (Defra) to new AD plants (AD Loan Fund	The budget for the RHI comes from general taxation.

[20] http://www.rhincentive.co.uk/library/regulation/08_Energy_Act.pdf

Country	Financing mechanism	Source of Finance
Germany	• Support in the form of FiT is provided on electricity from CHP which uses biomethane (guarantee of origin is required) and which utilises 100% of its heat. • A basic rate is offered for biogas and originally an additional top-up rate (technology bonus) was provided if the biogas is upgraded to biomethane (this bonus is now abolished), • Payments is if plant generates electricity and heat (so this FiT support is for CHP plants), • Other support mechanisms: ❖ Renewable heat quota which requires new buildings to supply a certain amount of their heat demand from renewable heat (including biogas) and biofuels quote requiring certain percentage of transport fuels to be supplied by biofuels. ❖ Tax exemption for biomethane, ❖ Priority grid access and transport for biomethane, ❖ Sharing of investment costs for grid connection, ❖ Facilitated biomethane transport	Funded through a levy on electricity consumers and paid to CHP operators on the electricity which comes from biomethane A Guarantee of Origin, (GOO) is required. In the case of BtG, the operator of the upgrading plant which treats the biogas to produce biomethane enters into a contract with the operator of a (high-efficiency) CHP plant on the gas grid that annually consumes the same amount of gas from the grid into which the biomethane plant is feeding. The CHP operator compensates the biomethane producer. Costs for installing a gas grid connection for a biomethane upgrading facility are equally shared between the operator of the upgrading facility and the grid operator.
France	• Biomethane producer support based on Guarantee of Origin system: biomethane producer sells to gas supplier at guaranteed tariff, gas supplier compensated for difference between cost of biomethane and cost of natural gas, • FiT for electricity generated from biomethane: varies by scale; bonus if high % of manure feedstock, • Biomethane: Base rate (varies by size) + bonus calculated according to feedstocks used,	Financed through levy on gas consumers

Country	Financing mechanism	Source of Finance
Netherlands	• Biomethane producer support on difference between production cost and energy price), • Tax reduction on investment in energy-conservation equipment used in biomethane plants, • Feed-in-tariff for biomethane plants (with total budget capped). Schemes bid in to funding rounds (i.e. funding on first come first served basis with low cost projects served first),	Financed through levy on consumers energy bills
Sweden	• End-user support but focussed on vehicle fuel applications (green car premiums, support for filling stations, • All types of biomethane use (at the end-user) is exempt from carbon dioxide tax as well as energy tax, • Investment programmes for farmers and municipalities with specific incentives for biogas from manure (farm-specific),	
Austria	• Feed-in tariffs for electricity from biogas / biomethane, • Base rate for biogas with bonus for biomethane upgrading and for high efficiency CHP, • With annual budget caps. The combined cap for liquid and solid biomass and biogas is €10m per year, and is reduced by ~2% per year.	Analogous to Germany, FiTs are paid to the electricity producer and funded via a levy on electricity consumption.

3 Stakeholder Responses

A stakeholder consultation was conducted as part of the economic assessment of biogas and biomethane study. Two questions were asked on financing mechanisms related to biomethane injection into the grid:

- What do you see as the pros and cons of supporting biomethane production via the end user of the biomethane versus support to the producer of the biomethane?
- If payments were made to the end user of the biomethane, do systems already exist for biomethane users to show in an auditable way their use of biomethane?

Ten stakeholders responded to the two questions above. A summary of the responses is given in the table below.

Table 2: Stakeholder responses to the consultation questions on financial support options

Question	Response
What do you see as the pros and cons of supporting biomethane production via the end user of the biomethane versus support to the producer of the biomethane?	There was agreement amongst all stakeholders that support should be provided to the producer of the biogas / biomethane rather than the end-user. This was thought to be less complicated and would help the industry get established, as the major investment is made by the biomethane producer and not the end-user.
If payments were made to the end user of the biomethane, do systems already exist for biomethane users to show in an auditable way their use of biomethane?	Four stakeholder stated that they were not aware of any existing systems. One of respondents added that a Green Gas Certification scheme will still be required regardless of whether payments are made to the end user or not. It was highlighted that there is an existing methodology for tracking gas shipments by the gas network operator which can be applied for biomethane injection in a similar way. Several users highlighted that even if payments to the end user are not the support mechanism used, traceability of transactions is required by the market participants to ensure guarantee of origin and protect against double counting. Gas grids and gas tanker distribution services are an energy store as well as delivery service, so all transactions can be net balanced on a monthly and annual basis (per existing Entry-Exit market arrangements with licensed gas Suppliers). Several respondents stated that they were involved in setting-up a biomethane producer registration and “certification of origin” system so that the production and use of biomethane can be validated. This is the Green Gas Certification Scheme study which is being managed by the International Energy Research Centre (See Section 4). The scheme will support a Producer Registration and Certificate of Origin for both biomethane and other renewable gas. It will validate and verify the production and use of the biomethane from source to end-user, i.e. what goes in can only be taken out, so that there is no double counting. This certification scheme will be available to support National reporting obligations if and where required, and will provide independent validation for consumers of their purchased volumes of renewable gas and associated carbon savings/footprint.

Additional recommendations were also given:

- The level of any future support for biomethane needs to be such, that in comparison to any future support for biogas electricity generation or CHP under REFIT, biomethane production is at least as economically viable as electricity and/or heat production.
- Regulation should define that metering and monitoring should be at point of entry to gas network or at point of gas tanker filling stations,

- Payments are preferably made to shippers rather than end-users as gas shippers/suppliers are much more likely to enter into long term stable relationships with producers than end customers, and direct payments to producers for gas placed on the market creates a certain level of security for the producer.

4 Options for supporting biomethane injection into the grid

This section compares the two approaches of incentivising biomethane injection into the grid:

- Incentivisation by payments made to the end-user
- Direct support to the biomethane producer

The pros and cons for the two approaches are also discussed.

4.1 Incentivising by feed-in-tariff payment made to end-user

Incentivising the end user requires the establishment of a green certification scheme for tracking the biomethane from the point of generation until it is consumed by the end user. The Green Gas Certification scheme (GGCS)[21] in the UK, for example, was initiated in 2011. The principle is that a certificate is issued for the generator who then transfers that to the shipper. The shipper then transfers the certificate to the end biomethane user (for example a CHP site). If there is no end-user requirement for the certificate, the shipper can redeem the certificate.

Requirements for implementation
In order for a GGCS to be implemented successfully, the biomethane injected into the grid needs to be tracked after it is mixed with natural gas in the grid. This can be achieved through mass and energy balances from the time the biomethane is injected until it is consumed by the end-user. This can help in providing evidence of the renewable feature of the gas and help track the parameters necessary to provide the relevant financial support (e.g. size of production plant, type of feedstock, energy efficiency, compliance with emission limits, etc.). Tracking the biomethane injected into the grid, also helps avoid the biomethane being sold to more than one user. Many countries have developed their own tracking systems in the form of biogas/biomethane registers.

Potential biomethane producers, the gas industry and gas users are collaborating in a project run by the International Energy Research Centre to develop a Green Gas Certification Scheme for Ireland. The study will begin early in 2017, and should complete in early 2018, by which time it will have developed a blueprint for the scheme. How quickly the scheme could be made operational after this will depend on a number of factors – not least the level of support and engagement that is received from stakeholders and policy makers - and is unlikely to be clear until the study is well underway. Given that development of such a scheme has already been initiated, the requirement for a tracking/certification scheme should not therefore be an obstacle to incentivising the BtG market via end-user payment. It should be noted though that the scheme would need to become operational on the same timescale that any end-user support mechanism was introduced.

Pros and Cons
Incentivising the end-user will facilitate the creation of the full supply chain. Also as the end-user will be able to choose and have contracts with their chosen suppliers, which may lead to reduction in costs of supply in the longer term. However, the biomethane market is currently absent in Ireland and in order to successfully incentivise this industry, investment in developing the infrastructure (i.e. biomethane upgrade plants) may also need to be considered. Encouraging the development of the infrastructure can be achieved through capital grants and other methods such as sharing the cost of connection to the grid (Section 1.2). Nevertheless, a feed-in-tariff system where payment is made directly to the producer (section 4.2) may still be required to establish the infrastructure and provide certainty.

[21] http://www.greengas.org.uk/

A system where payments are made to the end user means that support could be restricted to end users who are using biomethane for heat production, thus ensuring that all biomethane production is being utilised in the heat sector. However as discussed in Section 1, the RED currently stipulates that even if this is the case, in terms of its contribution towards renewable energy sub-targets, the biomethane injected must be allocated between the transport, heat and electricity targets in proportion to natural gas use in these sectors. Unless this accounting convention under the RED is changed, then the potential advantage of an end use support mechanism in ensuring that biomethane is preferentially used in the heat sector, and helps to meet the RES-H target would not be realisable.

A drawback of a 'payment to the end-user' system is the need to develop a complex system of administration, evaluation and auditing. Auditing of sites claiming the benefits (e.g. sites receiving the green gas certificates) is required in order to ensure compliance with legislative requirements in terms of metering, maintenance, sustainability and quantities of renewable gas produced in a given period. Furthermore, as end users have little investment in the biomethane production process, they can, unless a long term supply contract has been negotiated, easily switch biomethane providers. This can be a drawback for biomethane producers, increasing uncertainty and risk for them.

4.2 Incentivising by payment made to producer

An alternative approach is to support biomethane production via payments to the producer, based on quantities of biomethane they produce and inject into the grid[22]. This is the approach followed in several European countries such as the UK, France and the Netherlands. In the UK this approach is also applied to biogas operators producing heat for eligible (economic) uses, i.e. the subsidy payment under the RHI goes to the biogas heat producer rather than the end user of the heat.

Biomethane and biogas operators may prefer this approach as direct receipt of support payments by them, allows them to consider this as firm, 'bankable' income stream, which may help facilitate raising finance for the plant. While biomethane production is well established in other countries, and anaerobic digestion is a mature, commercial, technology, there is limited experience of it yet in Ireland and little familiarity with the technology by potential funders. An appropriate support mechanism targeted at the biomethane plant operator, could help to reducing the risk in biomethane projects, and make them more attractive to funders.

Requirements for implementation

Adopting this approach will require developing an accreditation process which ensures payments are made to the 'producer; of the biomethane. In the UK, the RHI Guidance states that where more than one entity is involved in producing the biomethane from biogas (or, ultimately, from biomass), the entity which carries out the final production process necessary to bring the biogas within the definition of biomethane under the RHI Regulations is to be regarded as the "producer" of that biomethane for RHI purposes. The RHI regulations state that biomethane producers will need to provide details of the process by which the applicant proposes to produce biomethane and arrange for its injection. This is to determine that the party is the producer of the biomethane, and has arranged access for its conveyance through pipes. The accredited biomethane production process under the RHI is the biomethane upgrade process (i.e. drying process for water removal, H_2S removal, CO_2 removal and any other impurity removal). A Network Entry Agreement (NEA) is usually made between the Gas Network Operator and the biomethane producer and can

[22] This approach could also be extended to supply of biomethane by road to end users who are not on the gas grid, if the point of payment is linked to a metering point.

thus be used as evidence for accrediting new installations in order to identify who should receive the payments. Odorisation of biomethane on site of the producer is evidence that the product was fully considered as ready for transport and injection into the grid before leaving the 'producer' site.

Pros and Cons

Direct support to the producer could help to get the industry established more quickly by directly rewarding the biomethane generator for investing in the technology, and the risk that this investment carries.

As discussed in Section 1, at present the RED does not allow biomethane injected into the grid to be allocated to specific sectors, and based on current gas use, only about half of biomethane injected could be counted towards the heat sector. However if this stipulation were be changed by the Commission, then direct support to the producer would not provide a lever for Government to encourage use of biomethane in specific sectors if it so desired e.g. in order to ensure that the RED sectoral targets are met. In considering the significance of this in regards to the RED targets, it should be remembered that at present it is not at all clear that EC will change the rules on how biomethane should be accounted for, and that post 2020, the EU has not set specific sectoral renewable energy targets (or indeed national renewable energy targets. Furthermore, biomethane projects have a relatively long lead time (typically 2 to 3 years) which would mean that relatively few plant would be likely to be operational by 2020, again meaning that the impact of this aspect will be relatively limited.

One further issue which would need to be considered if this type of support mechanisms was used is that biomethane which has been supported could be sold for use outside of Ireland. Double incentivisation could occur if, in the end users country a subsidy is available to the end user for the use of that biomethane. Procedures for accounting for this, and ensuring that no 'double incentivisation' occurs would therefore need to be developed if this approach is adopted. An additional issue which would need to be resolved is that the benefits from biomethane production, which would have supported by Ireland, could now accrue to another country. As production of biomethane grows within Europe, these are issues that are likely to be faced by a number of Member States, who will also need to produce solutions for these issues.

4.3 Comparison of the two approaches

Table 3 provides a summary of the pros and cos for the two approaches described above.

Table 3: Comparing the two approaches for supporting BtG

Criteria	Pros	Cons
Payment to Producer	• Experience in other countries (UK, France). Examples of requirements for implementing and accreditation system for BtG installations are available from other countries. • Simpler administration arrangements • Helps provide certainty for developers and many assist in securing finance • Will help assure producers that they can recover their costs • Can be implemented immediately without the need to wait for a tracking/certification scheme for biomethane to be operational	• Requires a 'tracking' system for biomethane to be set up if wish to identify which sectors biomethane is being used in. Would not allow allocation of biomethane to RES heat target, even if RED accounting rules are changed without this tracking system. • Would not provide any way to encourage use of biomethane in particular sectors • Biomethane which has been supported could be sold for use outside of Ireland. Double incentivisation could occur if biomethane production is subsidised in Ireland, but in the end users country a subsidy is available to the end user for the use of that biomethane.
Payment to End-user	• Experience in other countries (Germany) • Helps facilitate the development of the full supply chain starting from the generator to the end user • End-user can select own suppliers thus potentially leading to cost reduction in the longer term	• Requires tracking/certification scheme for biomethane to be operational. Such as scheme will impose additional administrative requirements and a system of evaluation and auditing, • End-users have little investment in production process and so can easily switch producer unless tied into long term contracts; this uncertainty for producers could be a disincentive to develop BtG plant • End users include both heat-only sites (e.g. boilers which have been operating on natural gas for many years) and CHP systems. A system based on end-user payments through support for electricity from biogas CHP' would not encourage use of biomethane at heat only sites. One way to address this would be to base payments on 'per kWh of biomethane used' rather than on 'per kWh of electricity generated'.

5 BioLPG

From 2017, Calor will be importing 6,000 tonnes of bio-LPG into Ireland from Rotterdam, where it is produced as a co-product in Neste's Hydrotreated Vegetable Oil (HVO) production facility. Feedstocks for HVO production are vegetable and waste oils, meaning that the bioLPG can be considered a renewable fuel[23]. However as fossil based hydrogen is used in the production plant, and as some of the hydrogen in the bioLPG is derived from water, the fuel cannot be considered wholly renewable. The UK Department for Transport have assessed this issue based on information provided by Calor and ruled that 93.2% of bioLPG can be considered to be of biological and renewable origin24, and that this will be used to determine the quantity of Renewable Transport Fuel Certificates (RTFCs) that bioLPG could receive if used as a transport fuel.

A similar process does not currently exist within Ireland for determining whether a fuel is renewable. However if support was provided for bioLPG in Ireland on the basis that it was a renewable fuel, then it would be necessary to take a view on the renewable content of the fuel, and how this should be determined.

Calor have indicated that for commercial customers, the price for bioLPG will be about 20% above conventional LPG prices. However the Department for Finance has indicated that if bioLPG is recognised as a sustainable renewable fuel, it will qualify for carbon tax exemption, which would reduce the premium. (Table 4). Calor report that the additional premium on bioLPG is to cover the cost of transportation from Rotterdam, and also the mass balance system they will be putting in place to allow tracking of the bioLPG. As such it will be a flat rate across all consumers.

Table 4 Current price for conventional LPG and indicative prices for BioLPG

	Conventional LPG[25]	Bio LPG	BioLPG if exemption from carbon tax given
	€/kWh	€/kWh	€/kWh
Commercial cylinders	0.125	0.1378	0.133
Bulk LPG (0 to 3 tonnes)	0.078	0.0908	0.086
Bulk LPG (3.1 to 40 tonnes)	0.065	0.0784	0.074

For existing LPG users, no capital expenditure is required to use bioLPG. However, the cost of producing bioLPG is higher than that of producing conventional LPG due to the additional treatment processes and fuel upgrade processes involved. The additional cost of BioLPG is typically 11 - 13% for most commercial users. While this higher price is likely to be a disincentive for many users, some will be willing to pay the higher price, as use of

[23] The EU define biofuels as 'biofuels' means liquid or gaseous fuel for transport produced from biomass (Directive 2003/30/EC on the promotion of the use of biofuels or other renewable fuels for transport). Under this broad definition bioLPG is a biofuel, and hence can be considered a renewable fuel. While bioLPG is not on the list of fuels that are definitely classed as biofuels in the Renewable Energy Directive, that list included only the most common types of biofuels that were produced or envisaged at the time the Directive was passed, and is not intended to be exclusive. The fact that bioLPG is not on the list does not therefore mean that it would not be considered a biofuel.

[24] Copy of letter from UK DfT to Calor of 23 June 2015, provided to Ricardo Energy & Environment by Calor.

[25] SEAI Commercial/Industrial Fuels, Comparison of Energy Costs 1 July 2016

bioLPG would reduce their corporate CO_2 emissions, and contribute towards achieving corporate CO_2.emissions reductions targets.

BioLPG could also offer a way to help bring renewable heat to off gas grid users currently using oil based systems. This would require capital expenditure for LPG storage and a new boiler, or where appropriate a CHP system. Therefore it may be possible to consider including new boilers and CHP systems using bioLPG as an eligible technology under the proposed RHI.

In assessing whether this is desirable, consideration should be given to security of supply and to the fact that there is currently only one commercial supplier of bioLPG to Ireland (Calor). Finally as bioLPG is likely to be blended with LPG, there will be a need to ensure in any support mechanism put in place that adequate tracing and monitoring mechanisms are in place (at both the supply and user end) to ensure that support is only given to bioLPG which is consumed.

Appendix B

Report on Feasibility of Supporting Biomethane through a Gas Levy

by Ricardo Energy & Environment

1 Introduction

This short report summarises current arrangements for the levy on electricity consumers and whether a similar mechanism could be used to facilitate a levy on gas consumers to support biomethane production for injection to the gas grid. Information for the report has been drawn from a review of relevant policy documents and discussion with relevant staff in the Department of Communications, Climate Action and Environment (DCCAE) and Commission for Energy Regulation (CER).

2 Public Service Obligation (PSO) for electricity

2.1 What is the PSO?

The Public Service Obligation (PSO) is a levy mechanism through which funding is raised for policy measures targeted at electricity generation in Ireland. The measures supported include the deployment of renewable electricity generation (under the Renewable Energy Feed-In Tariff (REFIT) programme), peat generation and conventional fossil fuel generation related to security of supply.

The levy has been in place since 2001 and is paid by all electricity consumers in Ireland. The funds raised are then used to compensate electricity suppliers that purchase electricity from relevant generators (e.g. renewable generators under REFIT) at an additional cost[26]. The proposed levy amount for 2016/17 is €392m[27], of which €302m is to support renewables. The proposed levy amount for 2016/17 is 21% higher than the 2015/16 PSO. The increasing cost of the PSO ley is of growing concern to government, with the impact on energy bills and the competitiveness of energy intensive industries often cited.

Originally the PSO was put in place to target security of supply concerns, with the revenues generated being used to support peat and some gas generation. Over time the purpose of the PSO has expanded to include renewables, initially through the Alternative Energy Requirement programme introduced in the early 2000s[28], and since 2009 through the REFIT programme. Through its provision of funding for the uptake of renewable generation, the PSO is seen as the primary funding mechanism through which Ireland aims to meets its renewable targets: to generate 40% of its electricity from renewable sources by 2020 and source 16% of all energy consumption from renewables by 2020.

2.2 How is revenue raised and managed?

The total levy amount to be recovered from consumers for a given year is calculated ex-ante by the Commission for Energy Regulation (CER). To do so, CER estimates the total amount which will be needed to support 'PSO parties' (i.e. those receiving support through the measures that the PSO funds including renewable generators supported by REFIT). In addition, an "R-factor" is added to correct for previous years where ex-ante estimates of required funding were different to the actual outturn funding provided. As such, calculating the 'R-factor' reflects actual audited relevant PSO plant costs, outturn System Marginal Price (SMP), outturn capacity payments received and outturn generation levels for the PSO plants. The 'R-factor' can be a positive or negative number depending on the circumstances.

The PSO levy is applied to all electricity consumers in Ireland. The actual rates applied to the different customer groups are determined by CER depending on the total forecast levy pot required. Different rate levels and structures apply depending on the type of consumer:

- domestic and small commercial customers pay a flat rate (or set fee) per household / business per annum.
- medium and large profile customers pay a fixed charge per kVA of maximum import capacity (and hence the charge scales in proportion to the likely size of user).

[26] http://www.dccae.gov.ie/energy/en-ie/Electricity/Pages/Pubic-Service-Obligation.aspx
[27] http://www.cer.ie/docs/001074/CER16252%20PSO%20Levy%202016-17%20-%20Revised%20Decision%20Paper.pdf
[28] http://ec.europa.eu/competition/state_aid/cases/135860/135860_435924_16_2.pdf

The balance is split roughly equally between the two groups: in 2016/17, domestic and small business users are proposed to fund €186m of the total €392m (47%), with medium and large industry customers picking up the remaining €206m (53%).

The steps in collection, payment and distribution of the levy are:

1. Electricity suppliers collect the levy from individual customers through their energy bills;
2. The ESB Networks collect the allowed PSO levy from electricity suppliers;
3. The ESB Networks then pass the collected funds to EirGrid;
4. EirGrid then re-distribute the funds to the suppliers depending on the levels of support they have provided to PSO parties over the period (e.g. purchases of renewable electricity from REFIT generators) ;
5. This is then re-distributed to the relevant generators/suppliers supported by the PSO in line the Power Purchase Agreements (PPAs).

Under REFIT, payments to subsidise renewable generation are based on a comparison of total market revenue (consisting of energy price, capacity payment and constraint payment) to a set reference price. If the total market revenue is lower than the reference price, generators are paid the difference through the revenue collected by the PSO. For example, if energy prices fall the PSO will make up a larger proportion of energy bills and will be required to cover any shortfall against the reference price. The reference price is adjusted annually in line with the Consumer Price Index, with different prices for different generation technologies[29].

2.3 The institutional framework

There are a number of different parties involved in the PSO levy and the subsidy schemes that it supports.

With respect to the revenue-raising element (i.e. the PSO levy), energy suppliers, ESB networks and EirGrid play important roles in the collection and distribution of funds.

At a policy level, the PSO levy and the associated subsidy schemes it supports are designed and mandated by the Irish Government (DCCAE) through relevant legislation, taking into account national policy objectives for the different areas.

The calculation of the total levy amount required and the individual rates for different groups of consumers is carried out by the CER. The levy is reviewed and updated on an annual basis, with the levy year running from October to the following September. CER calculate the PSO levy in accordance with Government policy and assist in ensuring the scheme is administered appropriately and efficiently. This includes calculating the actual costs incurred under the relevant PSO contracts/schemes to be remunerated.

With respect to REFIT (i.e. the 'spending' element of the policy), the DCCAE has responsibility for the design of the scheme, and also plays a role in its day-to-day running. DCCAE assesses applications from generators using qualifying technologies against the relevant terms and conditions for the subsidy scheme. If approved these are then included in a statutory instrument for CER to include in the PSO estimates. A letter of offer is issued to the potential generator, which while not contractual, provides the mechanism for which a Power Purchase Agreement (for 15 years) can be entered into with suppliers. This letter

[29] http://www.dccae.gov.ie/energy/SiteCollectionDocuments/Renewable-Energy/2016%20Reference%20Prices%20for%20REFIT.pdf

guarantees the floor or 'reference' price payment underwritten by the REFIT. This then enables the potential generator to put in place their finance and construct the plant.

2.4 Legislative Framework

The PSO is underpinned by a raft of legislation, summarised as follows:

- Section 39 of the Electricity Act, 1999 – CER is responsible for the imposition of the PSO levy on ESB, licence holders and holders of permits under the Electricity (Supply) Act, 1927.
- Statutory Instrument (S.I.) No. 217 of 2007 made under Section 39 of the Electricity Act, 1999 provides for the calculation of the PSO levy by CER to provide for the recovery of costs by all relevant parties
- Each year a new statutory instrument is made amending the initial S.I. No 217 of 2007 through which CER sets the amount to be recovered each year.

The over-arching legal basis for the PSO levy and its method of calculation are set out in regulations made under the Electricity Regulation Act 1999. This contains a specific section (Section 39) wholly dedicated to Public Service Obligations. This provides the relevant Minister with the power to direct CER to impose a PSO in relation to several objectives.

The European Commission (EC) defines state aid as: 'an advantage in any form whatsoever conferred on a selective basis to undertakings by national public authorities'[30]. Support schemes which are classified as State Aid require clearance from the Commission. The support offered though the PSO constitutes 'state aid' and required approval by the EC. The original Notification of November 2000 to the EC set out the broad areas that were to be supported by the PSO as listed in Section 39 of the 1999 Act:

- security of supply;
- regularity, quality and price of supplies,
- use of indigenous fuel sources; and,
- environmental protection.

Subsequent to this original Notification, new schemes that the Government wished to support via the PSO have been notified to the European Commission to request state aid clearance. S.I. No. 217 has also been amended by subsequent S.I.s to provide for the recovery of costs under the PSO for such schemes.

Additional schemes which have been notified to the European Commission and received state aid clearance to provide support include:

- a competition in 2005, referred to as "Capacity 2005", held by the CER due to security of supply concerns. This enabled the recovery of costs associated with peat plants and plants that entered the market in 2005
- the three phases of the REFIT scheme which supported renewable electricity generation

[30] http://ec.europa.eu/competition/state_aid/overview/index_en.html

3 Feasibility of a PSO on gas customers

3.1 Legislative feasibility

As discussed above, the PSO on electricity consumers is underpinned by a specific section in primary legislation (Section 39 of the Electricity Act 1999) and a raft of supporting secondary legislation. It is conceivable that a similar legislative underpinning would be required to place a levy on gas consumers that could be used to support biomethane production.

A review by Ricardo Energy & Environment of the primary legislation underpinning the gas market found that appropriate primary legislation may already be in place. The Gas (Interim) (Regulation) Act, 2002 contains a section dedicated to PSO – Section 21. This section mirrors Section 39 of the Electricity Act, which underpins the PSO on electricity consumers. Section 21(1) of the Act reads as follows:

The Minister may, following consultation with the Commission and such interested parties as determined by the Minister, by order direct the Commission to impose on such classes of natural gas undertakings as may be specified in the order in the general economic interest, public service obligations which may include security, including security of supply and technical or public safety, regularity, quality and price of supplies, and to environmental protection.

While it is the view of the study team that the Act is likely to provide a basis for any levy, they do not have the necessary legal expertise to provide a conclusive legal view. It is therefore recommended that if this route is to be pursued further legal advice is sought to provide a definitive assessment on whether the Act provides the required underpinning in primary legislation for a gas levy.

The legislative feasibility of such a levy was also discussed with officials at both DCCAE and CER in October 2016. In both cases, officials articulated in these initial discussions the view that both new primary and secondary legislation would need to be put in place to underpin the scheme. Further, the introduction of new legislation (in particular primary legislation) if required would take time to put in place. In addition, even if this was not the case (and the necessary primary legislation was already in place), secondary legislation will be required to define the detail of any proposed gas levy.

Discussions with stakeholders also indicated that State Aid clearance would be needed, which based on REFIT experience could take 6-12 months to acquire. However, given state aid clearance would be associated with the ‘spend’ element of any measure, this would be required regardless of how revenue is raised.

3.2 Operational feasibility

As discussed in Section 2, the existing PSO on electricity consumers is underpinned by a defined European and national legal framework, national policy framework and regulatory framework, with a number of entities involved and playing important roles.

It is considered unlikely that there would be any issues replicating the institutional and operational arrangements that underpin the PSO to develop a gas levy.

Similar entities exist overseeing the gas market as in the electricity market:

- energy suppliers supply gas to metered customers as they do for electricity;

- CER regulates the gas market as it does the electricity market;
- DCCAE oversees policy across all energy markets; and
- GNI operates the transmission and distribution gas system, as EirGrid and ESB do for the electricity market.

As such directly transposing the institutional structure and roles for the electricity PSO onto the gas market appears to be a feasible delivery model for a gas levy.

4 International examples

Funding mechanisms in three other European countries which directly support production of biomethane are summarised below. Of these, one in the UK is funded by general taxation and two, in the Netherlands and France are funded by surcharges on consumers' energy bills.

In the UK, biomethane producers receive a payment per kWh of biomethane injected to the grid under the Renewable Heat Incentive (RHI). The RHI which supports a number of other renewable heat technologies as well as biomethane, is funded by the Exchequer through general taxation funding. Early consultations on the design of the RHI indicated that the Government was considering what would be the most effective way to fund the RHI, including reviewing the Levy provisions in the Energy Act 2008, to set a levy on fuels used for heating[31]. The final detailed proposals for the scheme in 2011[32] however stated that the previous Government's plans for an RHI levy to fund the scheme were considered overly complex, and that it would be funded from general Government spending. This decision was also seen as alleviating the fears of a number of organisations and industries about the potential impacts on energy bills and the consequences for fuel poverty and energy intensive industries.

In France, biomethane producers can enter a 15 year contract with any gas supplier. The gas supplier receives a payment from a compensation fund to cover the difference between the cost of biomethane and the market price of natural gas. The relevant cost of biomethane is determined by the Ministry of Ecology. The consumer's contribution to the fund is calculated by the energy regulator[33]. The 'Contribution Biométhane' otherwise known as 'la contribution au service public du gaz (CSPG)' is a flat rate levy; rates for 2014 to 2016 are shown in Table 4.1.

Table 4.1 Gas Levy to Support Biomethane Injection (Contribution Biométhane) in France

	2014	2015	2016
No of biomethane plant supported	6	20	39
Money required for support (€M)	2.7	7.6	23.3
Levy to support biomethane (c/kWh)	0.72	1.53	4.92

Source: Commission de Regulation de L'Energie, 2015[34].

From 1 January 2016 rather than being levied separately, the Contribution Biométhane was included in the existing Taxe Interieure sur la Consommation de Gaz (TICGN), or Internal Tax on Natural Gas Consumption together with the Contribution to the Special Solidarity Gas Tariff (CTSSG)[35]. The TIGN has existed since 2014 and its original

[31] DECC, 2010. Renewable Heat Incentive. Consultation on the proposed RHI financial support scheme.
[32] DECC, 2011. Renewable Heat Incentive
[33] Reizine S, 2015. Biomethane injection in France
[34] Commission de Regulation de L'Energie, 2015 Délibération de la Commission de régulation de l'énergie du 15 octobre 2015 portant proposition relative aux charges de service public liées à l'achat de biométhane et à la contribution unitaire pour 2016. Available at http://www.cre.fr/documents/deliberations/proposition/(annee)/2015
[35] The Contribution to the Special Solidarity Tariff (Contribution au tarif spécial de solidarité) or CTSS) is chargeable to natural gas suppliers in proportion to the amount of natural gas that they supply to final consumers. It is used to finance the Special Solidarity Tariff (tarif spécial de
solidarité – TSS) that consists of a flat-rate rebate on the price of gas. It has been set at €0.2/MWh since 2014.

component (a tax on gas consumption) was levied on behalf of Customs and then integrated as revenue into the state budget. Gas consumed for large scale electricity generation and in in some energy intensive production processes and as a raw material were exempt from the TICGN in 2015[36].

In the Netherlands biomethane production is supported under the Sustainable Energy Production Plus (SDE+) scheme. This supports a range of renewable energy technologies producing electricity and, or heat as well as biomethane injection, by means of a feed-in premium. Producers receive a subsidy payment that is the difference between the standardised cost price for energy from the renewable technology and the price that they can receive on the market for the energy produced. Since 2013 the scheme has been funded by a surcharge on consumers and businesses energy bills[37]. The surcharge is levied on a per unit of consumption basis across both electricity and gas bills[38], with a declining surcharge the more is consumed. There are four bands for consumption. In 2014, the levy was 2.3€/MWh for electricity consumption up to 10 MWh (which would include most if not all households), 2.7€/MWh for consumption of 10 to 50 MWh, and much lower rates of €0.7./MWh and €0.03/MWh for very large energy users (above 10,000 MWh per year. The levy on gas similarly falls substantially with size of consumer – from €0.00046/m3 for domestic and small scale consumer to 0.0004€/m3 for very large consumers[39].

[36] Energy Climate Overview, 2015 edition. No.34 Energy taxation. Available at http://www.developpement-durable.gouv.fr/IMG/pdf/34_-_La_fiscalit_de_l_nergie-ok_GB.pdf

[37] Algemene Rekenamer, 2015. Promoting sustainable energy production in the Netherlands: Feasibility and affordability of policy goals

[38] http://www.auresproject.eu/files/media/countryreports/pdf_netherlands.pdf

[39] PWC, 2015. A European Comparison of electricity and gas prices for large industrial consumers.

5 Advantages and disadvantages of a gas levy

This section explores the possible advantages and disadvantages of a levy on gas consumers to fund support for biomethane production. Implicit in this assessment is a comparison to one or more alternative options. The main alternative funding option would be through general taxation[40] and this is used as a comparator in Section 5.1 and 5.2. Other alternative options are subsequently considered in Section 5.3 below.

5.1 Advantages

The key advantage of introducing a levy on gas bills to support biomethane injection is that this would be the option most consistent with the 'polluter-pays' principle – those who cause pollution should bear the costs of managing it to prevent damage to the environment or human health. In this case, the issue at hand is that natural gas from the grid is a non-renewable fossil fuel and releases emissions of greenhouse gases (GHG) when burnt. This impact is currently not captured in the gas price, i.e. it is a 'negative externality'. Consumers of natural gas can thus be seen as the polluter. If biomethane, a renewable fuel which releases no GHG emissions when it is burnt, is injected into the grid, connected consumers (the polluters) are those who would 'benefit', as the greenhouse gas emissions associated with their consumption are reduced. If biomethane were to be supported by a levy on gas bills, then only gas consumers connected to the grid who are metered would face the levy. As such, a gas levy would more efficiently allocate costs to the polluters (i.e. those creating the negative externality in the first place).

Funding through general taxation on the other hand would raise revenue from a much wider base and many of those contributing would not stand to 'benefit' from the biomethane injected. For example, those not connected to the gas grid would in part subsidise biomethane injection but are arguably not contributing to the specific externality to begin with (i.e. that natural gas supplied through the grid is non-renewable and its consumption emits GHG's). That said, although this would be a less 'economically efficient' solution, tax revenue is spent to meet national aims, objectives and obligations and the avoidance of penalties is of benefit to all taxpayers. It should also be remembered that similar arguments can be made for the wider RHI, which it is proposed will be supported through general taxation.

Furthermore, if a gas levy is charged per unit of gas consumption, this achieves the most efficient economic solution: those who use more gas contribute proportionally more to the negative externality created, and would also pay more towards addressing the damage as a result. It would not be possible to achieve as efficient a solution through general taxation as it would be more difficult to achieve these scaling effects.

This principle applies across all potential uses of biomethane injected into the grid, whether for heat, electricity generation, or transport. However, to maintain this link the gas levy should only be used to support biomethane injection and not wider biomethane production more generally. If revenues raised through the gas levy are used for production not injected into the grid (e.g. where it is provided for transport through other means of distribution), this would provide a 'benefit' to some who do not pay the levy, in this case consumers of non-renewable transport fuel.

[40] The Department of Finance does not allow hypothecation of funds, as such if taxation was used to fund subsidies for biomethane injection, this would be limited to general taxation and could not be linked to / funded through specific taxes.

Adopting a gas levy approach separates the raising of funds and provision of support to biomethane injection from annual budget setting processes. This is beneficial for potential investors as it could provide a greater level of confidence that a consistent level of support will be available on an on-going basis, hence reducing perceived policy risk.

More widely, this will also provide an additional, secondary incentive for the uptake of renewable heat in place of consuming gas from the grid. The primary incentive will be introduced by the subsidy paid to renewable heat technologies under the proposed wider RHI. In addition, the levy will provide a disincentive to consuming gas where this raises the unit price, promoting more efficient use and/or switching to renewable sources.

5.2 Disadvantages

A levy on gas bills could be more regressive than raising revenue through general taxation. Fuel poor households typically live in less efficient homes and hence need to consume more energy to achieve an adequate standard of warmth. As such, where the levy is defined per unit of consumption for the domestic sector, this could place a greater burden on more vulnerable households.

The UK Government considered funding the RHI (for all technologies) through a levy on suppliers of fossil fuels for heat[41].The Coalition Government decided the RHI would be funded from general taxation, in part due to the complexity of such an arrangement but also to alleviate the fears of a number of organisations and industries about the potential impacts on energy bills and the consequences for fuel poverty and energy intensive industries. That said, there are examples where a levy has been placed on energy bills to fund policies: this is the case for the UK's Renewable Obligation and Feed-in Tariff (FIT) schemes. Even though the FIT is levied on energy bills, a recent review found only limited evidence that the scheme had exacerbated fuel poverty as a result, in part due to the way a complex range of factors interact to define fuel poverty[42]. The original Impact Assessment for the FIT discussed fuel poverty concerns associated with a levy on bills but suggested the impact in part would depend on the extent to which the same households would benefit from the take-up of small scale generation[43]. In addition, it notes that the impact will also depend on the ability of households to take up other measures which could mitigate the effect: e.g. energy efficiency measures. This raises an interesting proposition that in fact it may be a more efficient solution to introduce the gas levy to target GHG reduction and manage any potential negative effects through other, dedicated fuel poverty policies. The potential to do this will depend on the existence and flexibility of such policies.

Of course the size of such potential effects will depend on the amount of costs to be levied on domestic households and the approach to doing so. If a gas levy was used to support biomethane in Ireland then there may be opportunity to manage any risk (at least in part) through the design of the levy framework, for example, by placing a fixed levy per household as per the electricity PSO rather than on a per unit of consumption basis.

41 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48041/1387-renewable-heat-incentive.pdf

42 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/456181/FIT_Evidence_Review.pdf

43 http://webarchive.nationalarchives.gov.uk/20121217150421/http:/decc.gov.uk/assets/decc/consultations/renewable%20electricity%20financial%20incentives/2710-final-ia-feed-in-tariffs-small-scale.pdf

Further, the proportion of the charge levied on domestic consumers could be reduced and targeted more on other sectors. It is also worth noting that both the Dutch and French Government's currently place a levy on consumers to subsidise renewable energy generally (Netherland) and biomethane injection, suggesting that these concerns were overcome in these countries.

Alongside the risks for domestic consumers, there could also be a risk of a double penalty associated with the gas levy for electricity generation. Just under half of gas consumed in Ireland is used for electricity generation. GHG emissions from the electricity sector are already targeted through the EU Emissions Trading Scheme (EU ETS), which places a cost on electricity generators which are passed on to consumers.

The first risk of double penalty is that with the introduction of a gas levy, consumers (e.g. households) would pay an additional cost associated with their direct consumption of gas for heat, and could also face an additional cost associated with the gas levy through electricity consumption. As noted, a significant proportion of electricity generation is from gas-fired sources and generators could pass on the cost of the gas levy directly to consumers. Whilst this is true, the externalities associated with both are separate effects: i.e. GHG's associated with the consumption of gas for domestic heating, and GHG's associated with the consumption of gas for electricity generation. As such even though households and businesses which consume both electricity and gas for heating could face a double penalty, this simply reflects that there are two separate externalities associated with gas consumption for all energy supplied to these entities. As such it is considered justified in this respect.

A second risk of a double penalty is associated purely with electricity generation: the introduction of a gas levy will also place an additional cost on electricity generation, alongside the cost of the EU ETS, both of which will likely be passed through to electricity consumers. Both policies are feasibly targeting the same externality (i.e. GHG's associated with gas consumption for electricity generation) and could be considered to overlap.

However, in theory, if the gas levy supports biomethane injection, this in turn should reduce the GHG intensity of the gas in the grid. This should then reduce the level of allowances which need to be purchased when using gas for electricity generation. As such it is conceivable that there would be some levelling effect between the two policies, reducing the potential for double-charging. Although in practice the ability for this levelling effect to appear will depend on the mechanics of the EU ETS policy itself, and in particular on how emissions factors are determined which feed into the levels of allowances required for electricity generation using gas, and whether these would respond to the introduction of biomethane.

Any analysis of possible double effects would also need to take into account the distribution of free allowances under the EU ETS: to the extent electricity generators receive such allowances, this too could mitigate the double-charging effect.

Further, there are other examples where additional incentives have been introduced alongside the EU ETS, hence in theory targeting the same externality. For example, the UK's carbon price floor sets a minimum price for carbon. This introduces an additional incentive on top of the price of EU ETS credits, which presents an additional cost to electricity generators. In this case, the price signal from the EU ETS is considered insufficient to offer incentive to shift away from conventional, fossil fuel generation to renewables. A similar logic could perhaps be applied to the production of biomethane.

Alternatively, this issue could be avoided altogether through the design of the levy. Large scale electricity generators could be exempt from the charge as is done e.g. in France, where gas consumed for large scale electricity generation is exempt from the collection of revenue to support biomethane.

5.3 Other alternatives

Two alternative funding sources to a levy on gas bills and general taxation were discussed with stakeholders.

Under the PC3 revenue review, CER granted GNI (the gas transmission and distribution network operator), on the basis of submissions from them, an “Innovation fund” of €8 million[44]. . GNI has already used some of this Innovation Fund to explore the potential for injecting biomethane into the grid. Money for the innovation fund is supplied, along with other permitted expenditure by GNI, through revenue from customers, i.e. funding for the biomethane projects is supported by all customers through the transmission and distribution operators’ Use of System charges and is hence spread across all gas consumers. There are restrictions to pursuing this as an approach to fund biomethane deployment more widely. First this mechanism is intended for innovation – at the point such projects increase in scale or are commercialised, these are no longer eligible for funding through this route. Second, it is possible that such a funding route would limit the range of potential biomethane suppliers which could access the market, given only GNI can reclaim costs in this manner.

A further alternative would be to include a levy under the existing PSO on electricity consumers. The existing PSO is predominantly a mechanism to support uptake of renewable energy in the electricity sector, and using it to also support biomethane injection would be an expansion of its role towards more general support of renewable energy. Furthermore, legal advice would need to be sought to definitively determine if the opportunities eligible for support under the existing PSO could include biomethane injection. Given much of electricity in Ireland is generated from gas, raising support for biomethane using the PSO on electricity consumers would in part reflect the polluter pays principle, but less effectively than a direct levy on gas, as consumers using gas for heat who are also ‘contributing to the problem’ would not contribute directly or in a proportionate way.

[44] CER, 2012. Decision on October 2012 to September 2017 transmission revenue for Bord Gáis Networks.