



An Coimisiún  
um Rialáil Fónais  
**Commission for  
Regulation of Utilities**

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# Biomethane Connections Policy

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**Decision Paper** [www.cru.ie](http://www.cru.ie)

The Exchange, Belgard Square North, Tallaght, Dublin 24, Ireland  
T +353 1 4000 800 | F +353 1 4000 850 | [www.cru.ie](http://www.cru.ie)

## CRU Strategic Plan 2025-27

### Vision, Purpose, and Values



#### OUR VISION:

Resilient, efficient, sustainable, and safe energy and water services for Ireland.



#### OUR PURPOSE:

We actively serve the public interest by regulating the provision of energy and water to Irish homes and businesses, while supporting the transformation to net zero.



#### OUR VALUES:

• Integrity • Professionalism • Openness • Accountability

## Executive Summary

Biogas is a renewable gas produced from agricultural waste and other organic material. It can be upgraded into biomethane by removing carbon dioxide and other impurities and once upgraded is suitable for injection into the gas network where it provides a low-carbon alternative to natural gas. The production of biomethane contributes to the circular economy by transforming organic waste streams into an energy source. Its potential to deliver large-scale decarbonisation while using existing network assets means that biomethane production and injection is being increasingly encouraged across Europe.

The National Biomethane Strategy, published in 2024, set out actions to foster the development of the biomethane market in Ireland from a baseline of < 0.1 TWh/ year and set a target of 5.7 TWh/year of indigenous biomethane production by 2030<sup>1</sup>. The first biomethane was injected into the gas network in 2020. To facilitate that, changes were made in 2018 to the connection policy and tariffing arrangements. Since then, the CRU has continued to review biomethane policy to ensure that it remains appropriate - facilitating the necessary investments in biomethane by GNI and allowing effective access to the gas network. For example, since 2018 the CRU has introduced:

- a maximum connection model, with connecting parties contributing 30% of connection costs;
- a funding model for connections that can adapt to the pace of development in the market and the actual number of biomethane plants connected to the network; and
- a biomethane connections incentive under Price Control 5 (PC5)<sup>2</sup> to encourage the timely and efficient delivery of biomethane connections to the network<sup>3</sup> with a potential reward/penalty of up to +/- €250k p.a. over the PC5 period.

In February 2026, the CRU also introduced an interim solution for reverse compression. The interim solution is designed to facilitate the continued investment in reverse compression in line

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<sup>1</sup> Department of Climate, Energy and the Environment and Department of Agriculture, Food and the Marine (2024), 'National Biomethane Strategy', available online [here](#).

<sup>2</sup> PC5 (Price Control 5) sets out CRU's decision on what revenues GNI, as the regulated owner and operator of Ireland's gas network, can collect from its customers in the period Oct 2022 – Sept 2027

<sup>3</sup> The Biomethane Connections Incentive is assessed annually on three criteria: timeliness, biomethane output, and market arrangements. CRU assesses GNI's performance in the round, taking all three into account in line with the PC5 balanced scorecard for this incentive. A performance assessed as Good will earn a reward of €0.25m p.a, Acceptable €0m p.a. and Poor will incur a penalty of €0.25m p.a ([CRU2024163](#)).

with the pace at which the market is developing. GNI has estimated that the interim solution will facilitate the injection of 437 GWh of biomethane into the grid. This volume equates to 7.5 % of the national biomethane target for 2030. GNI estimates that the interim solution will see spend under the flexibility pot increase from €10m to €22.85m.

To build on the actions already undertaken and in line with Action 5b in the National Biomethane Strategy <sup>4</sup>, the CRU consulted on the connection policy for biomethane projects and is now issuing a decision paper to ensure the policy captures the developments in biomethane policy and market advances. The consultation proposed changes to the economic test and financial security requirements which would have increased the number of projects that do not have to pay an incremental contribution for their connection and also sought to better align the financial security requirements with risk. Further changes were proposed to facilitate the introduction of a Centralised Gas Injection (CGI) facility owned and operated by GNI – the first of which will be at Mitchelstown Co. Cork and could facilitate annual injection of 700 GWh (12% of the national 5.7TWh target). This, according to estimates provided by GNI, will reduce emissions by c. 130,000 tonnes of CO<sub>2</sub> per annum when fully operational. The changes consulted upon proposed to treat the CGI as closely as possible to a direct connection.

In arriving at its final decision, the CRU has considered responses submitted to the consultation from 27 stakeholders. The CRU also notes the findings and conclusions contained in a recent CEER (Council of European Energy Regulators) study on injection and access to the wholesale biomethane market.<sup>5</sup>

### **Economic test for biomethane connections**

The consultation put forth a proposal to extend the economic test appraisal period from 10 to 15 years. This would (i) increase the number of biomethane connections, including smaller and those further away from the network, that would not incur a supplemental payment towards their connection and (ii) reduce the amount of any supplemental payment that was required.

The proposal to extend the appraisal period was supported by almost all respondents to the consultation, with some suggesting it should be increased to 20 years. The CRU acknowledges that the expected lifetime of a biomethane plant would tend to see it injecting into the network for longer than the 10 years currently used for the economic test. This view is reinforced by the

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<sup>4</sup> National Biomethane Strategy, *ibid*.

<sup>5</sup> [CEER Report - NRA'S Reflections on Enabling the Injection and Access to the Wholesale Market of Biomethane](#)

length of time financial supports are available in Ireland. For example, the CRU notes that the Renewable Heat Obligation (RHO) is set to be in place until 2045<sup>6</sup>. The RHO and the 2030 biomethane target provide a clear commitment to biomethane and its injection into the network in future decades. The CRU also notes that biomethane is the only low carbon alternative currently available to the gas network.

However, this is a nascent market and there remains a risk that individual businesses may cease operations for various reasons which would impose costs on gas consumers. On balance the CRU has decided to extend the appraisal period for the economic test to 15 years. This extension is expected to significantly reduce the cost burden on biomethane developers while maintaining a proportionate approach to protect consumers against stranding risks.

### **Financial security requirements for biomethane connections**

With the gas customers initially bearing a significant portion of the connection cost it is appropriate that there are safeguards to appropriately protect consumers from stranding of costs in the event that the project does not inject the forecast volumes of biomethane into the network. The consultation paper proposed to set these safeguards through financial security requirements so that they better reflect the risks that the financial security is designed to cover, with a limit on how much stranding risk is borne by the gas customer.

The proposal would have seen the level of financial security being linked to on the volumes injected by the biomethane project over time. Responses ranged from those supportive of the change to those requesting the need for financial requirements to be totally removed. There were also suggestions around how to better to tailor the financial security to the risk profile. Respondents highlighted the differing risks presented during the construction and operational phases. The CRU has evolved its proposals to capture the changes in risk between different project phases:

- **Construction phase** – during construction of the connection, financial security will be required to cover all costs involved in building the connection net of upfront customer contributions, excluding the cost of the Biomethane Network Entry Facility (BNEF).
- **Operational phase** – during the operational phase, financial security will be required to cover 70% of the costs involved in building the connection net of upfront customer contributions, and will include the cost of the BNEF. The financial security requirements will reduce in line with tariff revenues associated with the gas injected at the connection,

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<sup>6</sup> Renewable Heat Obligation (RHO) Bill 2025

until the cumulative revenues are sufficient to cover 70% of the socialised upfront costs. The period of operation for which financial security is required will no longer be limited to a maximum of seven years.

Compared to current arrangements, these changes will lead to significantly lower financial security requirements for all connections during the construction phase. Costs will be reduced for developers at a time when their projects are typically subject to substantial upfront expenditure and potential cash-flow constraints. During the operational phase, the requirement will also be lower than it would be if the current rules are applied. It will also be more closely aligned with the actual stranding risk of each connection than is the case at present, where the requirement for the financial security ends after 7 years of operation.

Taken together, the changes to financial security requirements and the extension of the economic test appraisal period should reduce the overall costs of connecting to the gas network for all biomethane producers. Connections that have already passed the economic test under current arrangements should experience a significant overall reduction in the cost associated with providing financial security. For connections that previously did not pass the economic test, these changes will lead to the connecting party needing to pay for less of the cost of the connection upfront. For these connections, the higher proportion of socialised costs may lead to more financial security being required; however, the net effect of the changes to the connection policy presented in this document should still lead to substantial cost savings for them.

Finally, while these changes reduce the cost faced by connecting parties to access the gas network, they continue to protect the gas customer from the risk of connection assets being stranded. The CRU's decision allows for these risks to be allocated more efficiently between the customer and the connecting party and constitute a proportionate risk sharing arrangement which protects consumers while also widening access to biomethane producers.

### **Cost allocation of CGI facilities**

Respondents welcomed the proposals to treat the cost allocation for a CGI facility owned and operated by GNI under the maximum connection model. These proposals would treat the CGI very similar to a direct connection. The CRU has decided to implement the changes proposed in the consultation and this will see:

- Cost allocation and financial security requirements being based on the entire cost of the CGI
- Connecting parties will contribute to 30% of costs on a pro rata basis, in line with contracted capacity

Although the consultation did not consider timings around a transition to a developers' choice model, respondents did highlight the benefits of the transition and questioned whether it should be offered now. PC5 set out the maximum connection model. It set out that GNI would table proposed options for the transition to a developers' choice model. CRU placed incentives on GNI to progress this work. The CRU will be evaluating progress in this regard under its PC5 implementation framework. The CRU expects that the proposed options would cover how the CGI will be treated under a developers' choice model.

The update to the biomethane connection policy outlined in this decision paper, following on from the introduction of the interim solution for reverse compression in February, represents significant steps in facilitating the growth of the biomethane market in Ireland. The updated policy will encourage biomethane injection from plants of all sizes and distances from the network, in line with the National Biomethane Strategy which noted that a mixture of large grid-connected plants and smaller plants utilising centralised injection facilities will be required to achieve the Climate Action Target of 5.7TWh of injected biomethane by 2030.

The changes to the economic test and financial security requirements will make it more financially viable for AD plants of all sizes close enough to the gas network to connect directly to the network. The CGI framework will offer an alternative route to those AD plants located further from the network to transport their biomethane by road for injection at a CGI facility.

Further to the decisions discussed in this paper GNI will update the Gas Networks Ireland Connections Policy Document and any other relevant documents. The CRU have engaged with GNI on the modifications to the Code of Operations required to implement these decisions and the Code of Operations will be updated when that process has been completed. The CRU will monitor and review the effectiveness of the updated policy through the PC5 Reporting and Incentives Framework to ensure it continues to remain fit for purpose in supporting the development of the biomethane industry and decarbonisation of the national gas grid, while also protecting the gas customer.

## **Public/ Customer Impact Statement**

Biomethane is a renewable fuel that can be injected into the gas network, directly replacing natural gas and reducing carbon emissions. Ireland's biomethane strategy sets a 2030 target for indigenously produced biomethane of 5.7 TWh - aiming to supply approximately 10% of the country's gas demand and reduce reliance on imported fossil fuels. The decisions set out in this paper see changes to the connection policy to facilitate biomethane developers' use of the network.

They see provisions being made for the introduction of a centralised grid injection facility owned and operated by GNI. This will be a first of its kind facility in Ireland and will facilitate biomethane producers located further away from the network to truck and inject biomethane into it. The first CGI will be located in Mitchelstown Co. Cork and will, when fully operational, enable the annual injection of 700 GWh (12% of the national 5.7TWh target). This, according to estimates provided by GNI, will reduce emissions by c. 130,000 tonnes of CO<sub>2</sub> per annum when fully operational.

Further changes are being made, which will see potential cost savings for biomethane developers connecting to the network – particularly for smaller plants or those further way from the network. Those changes relate to:

- (1) **The economic test** – the economic test will now be run over a longer period (15 years) than at present (10 years). The economic test calculates whether an additional payment must be made for connection to the network. The longer the period over which it is calculated, the more opportunity there is to reduce, or indeed avoid, any additional payment.
- (2) **Financial security** – the way in which financial security is to be calculated is to change, so that it better matches the financial exposure on gas customers if a biomethane project does not proceed as planned.

Collectively these measures will support the developing biomethane industry, decarbonising the gas network while balancing the risk to Irish gas customers.

# Table of Contents

|                                                                         |           |
|-------------------------------------------------------------------------|-----------|
| <b>Table of Contents</b> .....                                          | <b>8</b>  |
| <b>Glossary of Terms and Abbreviations</b> .....                        | <b>9</b>  |
| <b>1. Introduction</b> .....                                            | <b>11</b> |
| 1.1 The Commission for Regulation of Utilities.....                     | 11        |
| 1.2 Purpose & Structure of this Paper .....                             | 11        |
| 1.3 Related Documents .....                                             | 12        |
| <b>2. Background</b> .....                                              | <b>13</b> |
| Biogas and Biomethane .....                                             | 13        |
| Biomethane in Ireland .....                                             | 13        |
| <b>3. Regulatory Framework</b> .....                                    | <b>16</b> |
| <b>4. Economic Test and Financial Security requirements</b> .....       | <b>19</b> |
| 4.1 Economic Test .....                                                 | 19        |
| 4.1.1 Consultation Proposal.....                                        | 19        |
| 4.1.2 Summary of Stakeholder Responses.....                             | 20        |
| 4.1.3 CRU's Response .....                                              | 21        |
| 4.2.1 CRU's Decision.....                                               | 23        |
| 4.2 Financial Security .....                                            | 23        |
| 4.2.2 Consultation Proposal.....                                        | 24        |
| 4.2.3 Summary of Stakeholder Responses.....                             | 25        |
| 4.2.4 CRU's Response .....                                              | 26        |
| 4.2.5 CRU's Decision.....                                               | 30        |
| <b>5. Central Grid Injection Facilities</b> .....                       | <b>34</b> |
| 5.1.1 Consultation Proposals .....                                      | 34        |
| 5.1.2 Summary of Stakeholder Responses.....                             | 35        |
| 5.1.3 CRU's response.....                                               | 36        |
| 5.1.4 CRU's Decision.....                                               | 37        |
| <b>Appendix – Stakeholder Responses to Consultation Questions</b> ..... | <b>40</b> |

## Glossary of Terms and Abbreviations

| Abbreviation or Term | Definition or Meaning                                                                 |
|----------------------|---------------------------------------------------------------------------------------|
| <b>AD</b>            | Anaerobic Digestion                                                                   |
| <b>BNEF</b>          | Biomethane Network Entry Facility                                                     |
| <b>BIP</b>           | Biomethane Injection Point                                                            |
| <b>Capex</b>         | Capital Expenditure                                                                   |
| <b>CGI</b>           | Central Grid Injection facility                                                       |
| <b>CHP</b>           | Combined Heat and Power                                                               |
| <b>CNG</b>           | Compressed Natural Gas (referred to as bio-CNG when the compressed gas is biomethane) |
| <b>EU</b>            | European Union                                                                        |
| <b>GNI</b>           | Gas Networks Ireland                                                                  |
| <b>I&amp;C</b>       | Industrial and Commercial                                                             |
| <b>LNG</b>           | Liquified Natural Gas                                                                 |
| <b>MEC</b>           | Maximum Entry Capacity                                                                |
| <b>NBS</b>           | National Biomethane Strategy                                                          |
| <b>NORA</b>          | National Oil Reserves Agency                                                          |
| <b>NPV</b>           | Net Present Value                                                                     |

|             |                                                                                                                              |
|-------------|------------------------------------------------------------------------------------------------------------------------------|
| <b>Opex</b> | Operating Expenditure                                                                                                        |
| <b>PC5</b>  | PC5 is the fifth gas network price control carried out by the CRU. It covers the period from October 2022 to September 2027. |
| <b>RAB</b>  | Regulatory Asset Base                                                                                                        |
| <b>RFI</b>  | Request for Information                                                                                                      |
| <b>RGC</b>  | Reverse Grid Compression                                                                                                     |
| <b>RHO</b>  | Renewable Heat Obligation                                                                                                    |
| <b>RNG</b>  | Renewable Natural Gas (another term for biomethane)                                                                          |
| <b>RTFO</b> | Renewable Transport Fuel Obligation                                                                                          |
| <b>ROV</b>  | Remotely Operated Valve                                                                                                      |
| <b>TSO</b>  | Transmission System Operator                                                                                                 |

# 1. Introduction

## 1.1 The Commission for Regulation of Utilities

The Commission for Regulation of Utilities (CRU) is Ireland's independent energy and water regulator. The CRU was established in 1999 and has a wide range of economic, customer protection and safety responsibilities in energy and water. Our mission is to protect the public interest in water, energy and energy safety.

Further information on the CRU's role and relevant legislation can be found on the CRU's website at <https://www.cru.ie>.

## 1.2 Purpose & Structure of this Paper

In November 2025, the CRU published its proposals to update the Renewable Gas section of the Gas Networks Ireland Connections Policy Document . This was on foot of a review carried out in furtherance to action 5b of the National Biomethane Strategy. Following a review of the responses received from stakeholders, this paper sets out the CRU's decision as to how the Connections Policy Document will be updated to ensure it continues to facilitate efficient use of the gas network by biomethane developers as the industry develops and as Ireland moves towards its 2030 biomethane target of 5.7 TWh.

The paper is structured as follows:

- **Chapter 2** sets out the background to the biomethane industry in Ireland today.
- **Chapter 3** introduces the existing regulatory framework on the issues discussed in the biomethane connection consultation and this decision paper.
- **Chapter 4** discusses the consultation proposals and sets out the CRU's decision on the economic test and financial security.
- **Chapter 5** discusses the consultation proposals and sets out the CRU's decision on the charging arrangements and cost allocation for Central Grid Injection (CGI) facilities.

## 1.3 Related Documents

- PC5 Decision Paper; Transmission Revenue for GNI [CRU2023138](#)
- PC5 Decision Paper; Distribution Revenue for GNI [CRU2023139](#)
- PC5 Decision Paper; Regulatory Framework [CRU2023140](#)
- Gas Networks Ireland Connections Policy Document [\(Link\)](#)
- CRU Consultation - Biomethane Connections Policy Review [CRU2025186](#)
- CRU Information Note on the Interim Solution for Reverse Compression for Biomethane [CRU202608](#)
- CRU Decision on Interim RNG Distribution Tariffs and Call for Comments on an Enduring RNG Distribution Tariff Framework [CRU202622](#)

## 2. Background

### Biogas and Biomethane

Biogas is a renewable gas produced from organic materials such as agricultural waste, food waste, or wastewater sludge during a process known as Anaerobic Digestion (AD). It can be used on-site as a fuel for electricity generation or Combined Heat and Power (CHP). However, its high content of carbon dioxide and other chemical impurities makes it unsuitable for injection into the natural gas network. Biogas can be upgraded to biomethane – also known as Renewable Natural Gas (RNG) – by removing these chemical impurities.

Biomethane is a low-carbon alternative to natural gas that can be injected into the gas grid and used in all the same applications as natural gas. Although new infrastructure is required for the injection of biomethane into the grid, no changes are needed to the existing gas network. Therefore, the Government has identified the deployment of biomethane as a realistic and scalable pathway for decarbonising the gas system, while enhancing energy security and supporting rural development.<sup>7</sup>

Biogas must undergo several processing and safety steps to be converted into biomethane that meets the gas quality standard required for grid injection. Distance from the gas transportation network is an important factor when considering the method and feasibility of injecting biomethane into the grid. Where an AD site is close to the gas network, the developer may seek a direct connection to the gas grid. However, as the distance from the existing grid increases a point will be reached where the cost of a connection will no longer be economically viable.

### Biomethane in Ireland

The 2024 National Biomethane Strategy sets out a pathway towards significant expansion of the Irish biomethane industry.<sup>8</sup> The strategy sets a target of producing up to 5.7 TWh of indigenously sourced biomethane annually by 2030, aiming to supply approximately 10% of the country's gas demand and reduce reliance on imported fossil fuels.

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<sup>7</sup> Department of Climate, Energy and the Environment and Department of Agriculture, Food and the Marine (2024), 'National Biomethane Strategy', available online [here](#).

<sup>8</sup> Ibid.

The National Biomethane Strategy outlines an agri-led, farmer-centric model to engage rural communities in biomethane production. This model supports both larger-scale AD plants with direct pipeline connections to the gas network and smaller, dispersed plants. For smaller or more remote AD plants, the strategy proposes an approach based on transporting biomethane by road to centralised injection facilities.

The Biomethane Strategy outlined a framework of five interlinking pillars seen as critical to target delivery:

1. sustainability
2. demand for biomethane
3. bioeconomy and the circular economy
4. economics of biomethane, and
5. enabling policy requirements

Each pillar has been aligned with 25 key strategic actions which address the challenges and support the opportunities AD and biomethane production has to offer. There are a wide range of actors across each of these pillars. Pillar 5 is of particular relevance to the CRU in its role as the independent energy regulator dealing with connection policy.

At present, there is one privately operated facility injecting biomethane into the distribution network in Co Kildare, which has been operational since 2020 and acts as an injection point for biomethane delivered by road. A number of biomethane plants are due to connect to the gas network in 2026, and these numbers are anticipated to grow over the coming years to meet the 2030 target. GNI are also developing the first CGI facility in Mitchelstown, Co Cork, which will be the first of its kind in Ireland.

GNI provides a package of information on its [website](#) for potential biomethane producers seeking a grid connection, outlining the steps involved in obtaining a connection. The process involves information gathering by GNI and sharing of some data about the network and network constraints to assist the applicant assess the viability of a possible connection. GNI intends to provide more detail on the capacity of the network to accommodate more biomethane

connections. CRU notes that similar schemes have been beneficial in other EU countries <sup>9</sup>in helping developers to identify the optimal biomethane connection points to the network.

In 2025 the Government confirmed the introduction of the Renewable Heat Obligation and approved the drafting of the Renewable Heat Obligation Bill 2025.<sup>10</sup> Once in place, the Renewable Heat Obligation will require suppliers of fossil fuels used for heating to demonstrate that a proportion of the energy they supply comes from renewable sources. The scheme aims to support emissions reductions in the heat sector, improve energy security, and help meet Ireland's binding EU renewable heat targets. Recently, the European Commission issued a formal Detailed Opinion<sup>11</sup> on an element of the scheme. This Opinion is being considered by the Department of Climate, Energy and the Environment but is not expected to delay the introduction of the scheme.

The National Biomethane Strategy also contains actions for relevant stakeholders to progress the development of the Irish biomethane industry, including Action 5b which calls for a review of the biomethane connection policy. That review has taken place, culminating in the publication of a consultation paper and request for stakeholder submissions in November 2025. This decision paper follows on from the connections policy review and presents the CRU's decisions on proposals relating to the economic test and financial security requirements placed on parties seeking a connection to the gas network to inject biomethane and the regulatory treatment of centralised grid injection (CGI) facilities.

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<sup>9</sup> CEER Report; *ibid*, 3

<sup>10</sup> Department of Climate, Energy and the Environment (2025) 'Renewable Heat Obligation Bill 2025', available online [here](#).

<sup>11</sup> [TRIS - European Commission: Notification of Ireland's Renewable Heat Obligation Scheme](#)

### 3. Regulatory Framework

The EU hydrogen and gas decarbonisation package, comprised of Directive (EU) 2024/1788 and Regulation (EU) 2024/1789, establishes common rules for the internal markets for renewable gas, natural gas and hydrogen throughout the EU. The package updates the EU gas market framework to support the integration of renewable and low-carbon gases, including biomethane, into existing gas networks and markets. The Directive is due to be transposed into Irish law by the 5<sup>th</sup> of August 2026, providing an important regulatory reference point for the future treatment of renewable gas and biomethane.

Ahead of the first biomethane injection facility connecting to the Irish gas network in 2020, the CRU carried out a review of the regulatory framework for the gas network to ensure that it facilitated the safe and efficient injection of gas. That review resulted in changes to the CRU Renewable Natural Gas Connection Policy<sup>12</sup> and the rules governing the operation of the natural gas network, which are set out in the Code of Operations<sup>13</sup>. The CRU also reviewed and accepted a material change to GNI's gas safety case for biomethane. Since then, the CRU carried out an in-depth review of GNI's proposals for biomethane as part of setting the price control on GNI for PC5, which is the fifth such control the CRU has carried out. The PC5 decision set out the treatment of costs, and ultimately the revenues that GNI can collect from its customers, from October 2022 to September 2027.<sup>14</sup>

In its PC5 submission, GNI provided detailed information on the anticipated volume of biomethane connections and how it planned to accommodate them. GNI proposed a mixture of direct connections and centralised injection facilities. To ensure that GNI's activities could be adapted to match the growth of the biomethane market, an uncertainty mechanism was introduced to adjust revenues to align with the actual number of biomethane connections needed in any given year.

A Biomethane Connections Incentive was also introduced in PC5 to strengthen economic signals on GNI to meet the growth in the biomethane market and support the national biomethane target

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<sup>12</sup> [CRU Renewable Natural Gas Connection Policy Decision](#)

<sup>13</sup> [Code of Operations](#)

<sup>14</sup> Commission for the Regulation of Utilities (2023), 'CRU Decision on the PC5 Regulatory Framework' (CRU2023140), available online [here](#).

of 5.7 TWh in 2030.<sup>15</sup> That incentive included a financial reward / penalty depending on GNI's performance. Each year GNI will submit a Biomethane Connections Report to demonstrate its progress on biomethane connections. Each report will be reviewed by the CRU in order to assess GNI's performance and then published. Ultimately, GNI's performance could see it recover or forego €0.75m in revenues over the PC5 period.

PC5 confirmed that biomethane connections would be offered under a maximum rather than a minimum model. Under the maximum model GNI would install, own and operate a significant amount of the connection equipment. Under the minimum model much more of the connection could be provided by the connecting party. A developers' choice model would allow the connecting party to choose between the maximum or minimum approach. PC5 provided for two CGI facilities to be developed by GNI under the maximum connection model. A CGI is a facility where gas transported via the road network can be injected into the network and is an asset that can be used by multiple parties.

The PC5 decision acknowledged that whilst a developers' choice connection model could bring benefits, there may be practical challenges realising those benefits in the short-term. This reflects the relatively new nature of the biomethane market and the need for time to further develop wide expertise in this area in Ireland. Therefore, the PC5 decision stated that once the market is sufficiently mature, the transition to a developers' choice connection model would be further considered.

In reference to charging arrangements the PC5 decision confirmed that, under the maximum model, the connecting party would contribute 30% of the connection cost upfront (subject to an economic test set out in the connection policy), with the remainder socialised through network tariffs. This level of cost sharing is in line with the connection policy for most demand connections of a comparable size such as small or medium Industrial and Commercial (I&C) or Institutional connections.

The Connections Policy requires that all new renewable gas connections are required to make a standard contribution of 30% of the estimated connection costs for the injection facility. The remaining 70% will be recovered through network tariffs over the following ten years. GNI carry out an economic test to determine whether sufficient tariff revenue would be generated to cover the socialised costs of the connection within the ten years, and if the connection costs would not

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<sup>15</sup> When the PC5 decision was published in 2023, the national target for biomethane production by 2030 was 1.6TWh. It was subsequently increased to 5.7 TWh in the National Biomethane Strategy, as noted in the CRU's decision on the implementation of the PC5 regulatory framework ([CRU2024162](#)) and accompanying User Guide ([CRU2024163](#)).

be recovered in this period then the connecting party must pay an additional upfront supplemental charge. Financial security is also required to be put in place for all renewable gas connections for a period of seven years. The requirement for financial security is to protect gas consumers from biomethane projects not progressing as planned and not contributing as much as forecasted to the cost of its connection. The amount of financial security required reduces over the seven-year period in line with the amount of gas injected into the network.

Proposals for changes to the economic test and financial security requirements were presented in the consultation paper, alongside proposals on the charging and cost allocation arrangements for CGIs. Following a detailed review of responses received, the CRU's decisions on these proposals are presented in the following sections.

## **4. Economic Test and Financial Security requirements**

As mentioned earlier, the full cost of a connection to the gas network is not initially borne by the connecting biomethane developer. The economic test and financial security requirements recognise this and are designed to provide an appropriate balance between the burden placed on the gas customer and the connecting party. In this regard, the economic test is designed to ensure that, over time, the socialised costs will be recouped through the tariff revenues associated with the injected gas. The financial security requirements are in place in the event that a connecting project does not proceed as expected, resulting in a shortfall in revenues. The responses to our economic test and financial security proposals presented in the consultation paper as well our decisions on these matters are now discussed in turn.

### **4.1 Economic Test**

The economic test calculates whether GNI will receive sufficient revenues from the new biomethane connection to cover the socialised costs of the connection, by considering the amount of biomethane that will be injected into the network and the associated revenues from network tariffs. Currently, the economic test is carried out over a period of 10 years (the appraisal period). If the revenues over the appraisal period are less than the socialised costs, the connecting party must pay a supplemental contribution to cover the shortfall. This is additional to the standard 30% customer contribution.

#### **4.1.1 Consultation Proposal**

The consultation paper outlined a proposal by GNI to extend the economic test appraisal period for biomethane connections from 10 to 15 years. GNI stated that this would provide a more realistic and policy-aligned basis for assessing the viability of biomethane connections. GNI also considered alternative approaches of maintaining the current 10-year appraisal period or extending the period to 20 years.

In presenting their proposals, GNI noted that the current 10-year period was intended to strike a balance between reflecting the true technical life of AD plants and protecting the network and its users from the risk of stranded assets if these plants fail. However, GNI considered that the 10-year period fails to capture the long-term financial viability and benefits of biomethane plants and

stated that using the wrong age profile for biomethane production facilities could lead to suboptimal network assessment and development and understate the length of viable network connections. Given the dispersed location and the scale of projects that they are currently aware of, GNI indicated that most of these projects were unlikely to pass the economic test over a 10-year period and would therefore be required to pay a supplemental contribution on top of the 30% standard contribution, significantly increasing total connection costs.

GNI noted that if the economic test fails to reflect the long-term value of these connections to the network and to Irish society more generally, it risks slowing the pace of project delivery, deterring investment, and undermining the viability of the projects that will be needed to support Ireland's energy transition. GNI expressed its view that a 15-year horizon better reflects the typical 20 to 25-year operational life of AD facilities and would significantly improve the economic viability of many projects. GNI's modelling indicated that extending the period to 15 years would see a typical 40 GWh/year capacity AD plant being able to potentially locate up to 4 km away from the distribution network, without needing to pay a supplemental contribution. The maximum viable distance for a plant of this size currently stands at just under 2km. GNI noted that, based on their information, a 15-year appraisal period is likely not sufficient for all potential projects to avoid the need to pay a supplemental contribution entirely but that the amount they would have to pay would be substantially reduced.

As a result, GNI maintained that a 15-year appraisal period struck a reasonable balance: it improved alignment with project lifespans and the national 5.7 TWh target, while still limiting the financial exposure of the wider gas customer base.

The CRU asked for stakeholders' views on the following question regarding the economic test –

*Question: Do you agree with the proposal to extend the appraisal period for the economic test from 10 to 15 years for biomethane connections?*

### **4.1.2 Summary of Stakeholder Responses**

The consultation was open for responses from the public for seven weeks, from 25<sup>th</sup> November 2025 to 12<sup>th</sup> January 2026. Submissions were received from 27 respondents (listed in the Appendix).

The following is a brief summary of the stakeholder responses to the question about the length of the economic test appraisal period. A detailed summary of the responses can be found in the Appendix at the end of this paper. All responses will be published on the CRU publications website unless stakeholders requested that their response remain confidential. There was extensive support from respondents for the proposal that the economic test period should be

extended beyond 10 years, although there were different views on how long the extension should be. Some respondents supported extending the appraisal period to 15 years as proposed, but the majority noted that an extension to 20 years would be more appropriate. Several others commented on the significance of the forthcoming Renewable Heat Obligation (RHO), noting that it would reduce stranding risk significantly by providing long-term policy certainty. Several respondents noted that the current 10-year period was significantly below the expected operational life of a biomethane plant.

A number of respondents noted that increasing the appraisal period would reduce costs for biomethane developers by decreasing or eliminating the supplemental contribution, cutting upfront costs and encouraging a wider geographic spread of AD plants by extending the distance from the gas grid where a connection is likely to pass the economic test.

GNI agreed with the proposal to lengthen the economic test appraisal period to 15 years, stating it would increase the potential number of biomethane plants connecting to the gas network by extending the distance that a plant can be located from the gas network without incurring a supplemental contribution, and noted that extending the appraisal period to 15 years aligns well with international best practices .

### **4.1.3 CRU's Response**

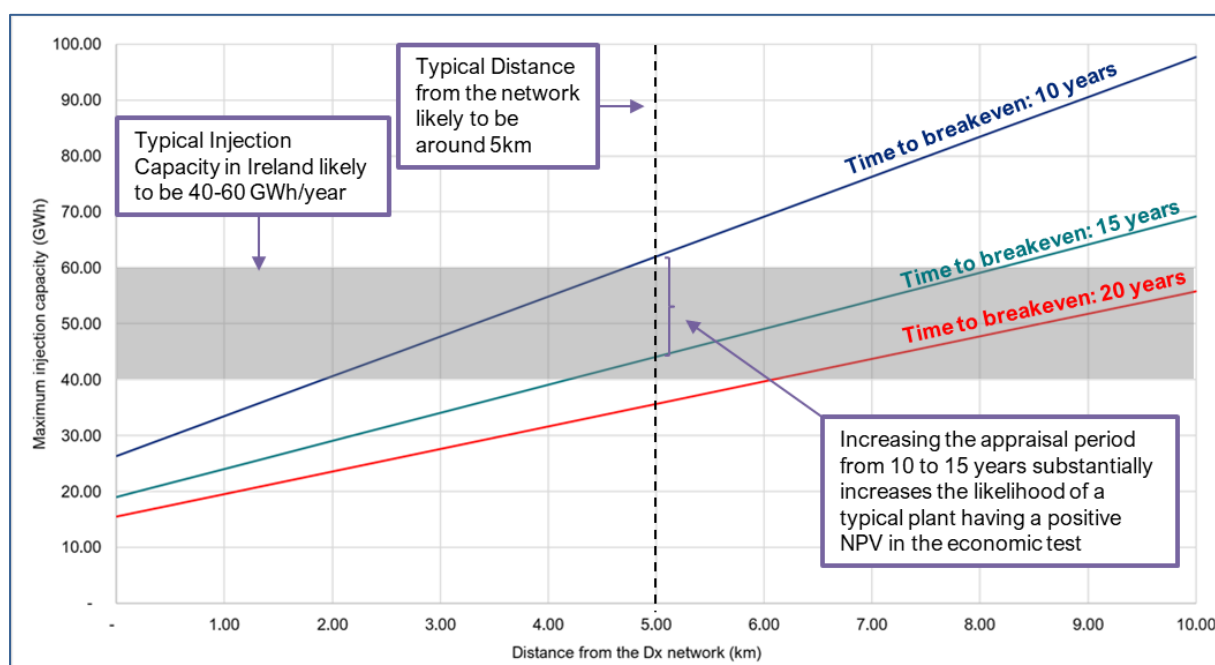
The CRU notes that almost all respondents to the consultation agreed that the appraisal period should be extended beyond 10 years. The CRU recognises that a longer period would capture a significantly greater portion of the revenue stream associated with a biomethane connection, thereby improving the likelihood that such projects pass the economic test without requiring a supplemental contribution. The CRU notes that increasing the appraisal period would assist both smaller plants and those located further away from the network.

Extending the appraisal period beyond 15 years was suggested by a significant number of respondents who stated that a longer period would be more consistent with the expected life of a biomethane plant. The CRU acknowledges that it is likely that a biomethane plant will continue to inject biomethane beyond the current 10-year economic test appraisal period and pay network tariffs for longer than is accounted for in the economic test. The CRU recognises that the industry is supported through the national target, and the actions and supports set out in the biomethane strategy. However, this is a nascent market and there remains a risk that individual businesses may cease operations for various reasons which would impose costs on gas consumers. On balance the CRU considers that extending the appraisal period in the economic test to 15 years is appropriate and strikes the right balance between the cost burden on customers and the connecting party. This extension is expected to significantly reduce the cost burden on

biomethane developers while maintaining a proportionate approach to protect consumers against stranding risks. Any further extension would increase this risk, while also having a relatively smaller impact on the costs faced by developers.

Figure 1 shows the expected impact of this change. The break-even lines indicate the effect that plant size and distance from the network have in whether a project would break even and pass the economic test. All plants above the break-even lines would pass the test. All those below the line would need to pay a supplemental contribution. Breakeven lines are presented for 10, for 15 and 20 years, corresponding to potential appraisal periods in the economic test. It can be seen that the impact of changing the appraisal period from 10 to 15 years is greater than the change from 15 to 20 years and that the increase from 10 to 15 years results in a greater portion of the typical sizes and geographical spread of biomethane plants avoiding a supplemental contribution. In addition to fewer plants having to pay a supplemental contribution when the appraisal period is increased to 15 years, any supplemental contributions that are still required will be significantly reduced (i.e. by extent of the revenues in the last 5 years of the appraisal period).

**Figure 1:** Illustration of the combinations of injection capacity and distance from the network expected to lead to an NPV of zero in the economic test



Source: CRU & CEPA analysis based on illustrative connection costs provided by GNI. Real costs and economic test NPVs may differ depending on the unique characteristics of each connection.

## 4.2.1 CRU's Decision

The CRU has reviewed the consultation responses and, giving due regard to the expected lifetime of an AD plant and the government supports available to developers, considers it likely that a biomethane plant will continue to inject biomethane beyond the current 10-year economic test appraisal period and pay network tariffs for longer than is accounted for in the economic test. As such and recognising both the national biomethane targets and the unique position of biomethane as being the only renewable alternative to natural gas currently available to the network, the CRU considers, on balance, that there is merit in extending the economic test from its current 10-year horizon.

The CRU notes that this position was supported by most of the respondents to the consultation and further notes that a significant number suggested that the period should be extended to 20 years. The CRU has considered the optimal length of the appraisal period and agrees with the position put forward by GNI that extending it beyond 15 years would create an excessive stranding risk which would be passed on to consumers in the absence of a substantial increase in financial security requirements. The CRU has therefore decided that extending the period to 15 years strikes the right balance between the financial requirements for biomethane developers and maintaining appropriate safeguards. This change should facilitate an increased number of biomethane plants, including smaller projects and those further away from the network, to connect to the network, substituting natural gas and, in doing such, reducing Ireland's carbon emissions and progressing towards Ireland's 2030 targets.

### **Decision**

The appraisal period for the economic test for biomethane connections will be extended from ten to fifteen years.

## 4.2 Financial Security

Financial security is closely linked to the economic test. While the economic test assesses the expected increase in network tariff revenues against the connection costs borne by the wider consumer base, financial security requirements protect against the risk that those revenues do not materialise in practice. In other words, the economic test assumes that the gas will flow as forecast while the financial security requirements protect consumers from the risk that it does not.

GNI has indicated that obtaining financial security can represent a significant burden for many biomethane producers and act as a barrier to entry, potentially deterring otherwise viable projects

from connecting to the network. In practice, the exact application of the financial security requirement depends on the credit rating of the connecting party. If the connecting party or its parent company meets a minimum credit rating threshold, then a simple letter of commitment to cover the liability, or a parent company guarantee to the same effect, is sufficient.<sup>16</sup> However, a substantial number of potential biomethane producers in Ireland today may not meet this threshold and would need a bank or other financial institution to sign a letter of credit on their behalf. Industry stakeholders have highlighted to GNI that financial institutions are aware of the nascent stage of the Irish biomethane industry and are likely to only issue such letters of credit in the presence of significant guarantees or at a relatively high cost.<sup>17</sup> This financing cost is incurred by producers regardless of whether biomethane injections follow the projected profile or not. In discussions with the CRU for the biomethane connections policy review, GNI indicated that this can constitute a considerable challenge for biomethane projects.

## 4.2.2 Consultation Proposal

The CRU considered a number of proposals regarding the financial security requirement and ultimately proposed one option for the consultation. GNI had proposed that the current financial security requirement of seven years should be retained, in tandem with the extension of the economic test appraisal period to 15 years. However, there was a concern that this would see eight years of “tail end risk” to the consumer where financial security would not be in place to safeguard against lower-than-forecast injections.

CRU instead proposed an alternative approach that would better align the financial security requirement to the stranding risk that the gas customer is exposed to, rather than applying a uniform time-based requirement to all projects. This would entail financial security requirements being based on injection volumes required to break even in the economic test. For each connection, GNI would calculate the volume of gas which needs to be injected before the project breaks-even in the economic test (i.e. present value of revenues from network tariffs = socialised costs). The financial security requirement would then be set to cover a specific percentage of that volume. With the current financial security requirements set as seven years of a 10-year economic test period, the CRU considered that, on balance, this portion should be set as 70% of the break-even volumes. This would see the connecting party providing financial security to

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<sup>16</sup> The threshold is a BBB credit rating from S&P or Fitch, or a BAA+ by Moody's. Source: Gas Networks Ireland (2017) 'Financial Security Policy', version 4.0, available online [here](#).

<sup>17</sup> At this early stage of development of the Irish biomethane industry, the cost of finance is likely to include a relatively substantial risk premium.

cover the revenues associated with 70% of the biomethane injection volumes required for the project to break even in the economic test.

The consultation document also discussed an alternative option considered by GNI to exclude the cost of the Biomethane Network Entry Facility (BNEF) from the financial security requirement. GNI noted that the BNEF constitutes a major part of the connection equipment, and is a modular, relocatable asset which could potentially be redeployed to other locations if a project fails. On this basis, it could be argued that the BNEF does not pose the same stranding risk as the rest of the connection infrastructure. However, GNI ultimately considered that there could be practical difficulties in the removal of the BNEF from an operating plant, possibly necessitating the complete shutdown of the facility, disrupting ongoing operations and rendering the facility non-functional. GNI stated that this requirement for the full closure of the plant could have severe consequences for the developer and concluded that removing the BNEF from financial security requirements would be difficult to implement and could unintentionally increase risk exposure.

The CRU asked for stakeholders' views on the following question regarding the financial security requirement –

*Question: Do you agree with the proposal to set the financial security requirements based on 70% of the injection volumes to break even under the economic test?*

### **4.2.3 Summary of Stakeholder Responses**

The following is a brief summary of the stakeholder responses to the question of financial security. A detailed summary of the responses can be found in the Appendix at the end of this paper.

There was a wide range of responses on the proposal to base the financial security requirements at 70% of the break-even injection volumes as set in the economic test.

A large number of respondents argued for the complete removal of the financial security requirement for biomethane connections, with some considering that the existence of arrangements such as feedstock or offtake agreements should provide enough evidence of financial stability.

A small number of respondents, including GNI, favoured retaining the current time-based approach to financial security. Several other respondents favoured the volume-based approach, with some suggesting that the % of the break-even injection volumes could be lowered from the proposed 70% to 50% or below.

A number of respondents suggested that the different risk profiles between the construction and operational phases of a biomethane connection should be reflected in a two-stage approach to financial security.

Some respondents noted that the BNEF is a modular and relocatable piece of equipment that could be redeployed elsewhere in the event of a plant failure and as such it should not be included in the financial security requirements.

Other miscellaneous responses included the following suggestions:

- Exclude VAT from the financial security calculation during the pre-operational stage
- Widen the list of potential financial security instruments
- Different financial security arrangements should apply to renewable gas generators and demand customers
- Convene a working group with industry stakeholders to co-design financial security requirements that are fit for purpose for renewable generation.
- Costing figures, worked examples, analysis and details about the calculation of the financial security requirement should be made available

#### **4.2.4 CRU's Response**

This section discusses the CRU's views on the consultation responses and the CRU's decision.

##### Removal of financial security requirements

The CRU does not consider it appropriate to remove the financial security requirement altogether for biomethane connection. These requirements are to protect the customer from the risk of a project not proceeding as planned. They protect consumers against the risk that the injection volumes assumed in the economic test do not materialise, and / or that the connection becomes a stranded asset. This stranding risk exists and will in fact be increased by extending the economic test appraisal period from the current ten to fifteen years. It is therefore important to maintain a proportionate financial security requirement that protects consumers from this risk while also balancing this need against the cost that it implies for biomethane producers.

The CRU recognises that demand connections differ from biomethane connections in many ways but does not share the view that this would justify removing the financial security requirement for biomethane connections. The cost of biomethane connections is partly socialised, which introduces a potential stranding risk for the gas customer. The financial security requirement is aimed at protecting the gas customer from that risk.

### Form of financial security and removal of VAT

The CRU notes the views expressed by some stakeholders around the form of financial security accepted by GNI, as well as requests to remove VAT from the financial security calculations. However, the CRU does not consider these changes to be in scope of its review of the biomethane connection policy, as they relate to GNI's financial security requirements for all connection types, not just biomethane, and the CRU notes that GNI is required to apply VAT as per existing legislation.

### Removing or reducing requirements based on specific risk assessment

Some respondents argued that financial security should not be required for connections which are underpinned by long-term gas purchase agreements. Others argued that once a biomethane plant has reached final investment decision there should be no requirement for financial security as the risks associated with the plant will be lower.

The CRU does not consider that having signed a gas purchase agreement, or having reached final investment decision, is in and of itself sufficient to conclude that a connection poses minimal stranding risk of the gas connection. Those agreements and decisions would have been conducted from the point of view of the risks presented to the biomethane developer. That risk profile will be dependent on the specifics of its business model and how the business is established (e.g. is it a special purpose vehicle). As such we do not consider it appropriate to remove the need for financial security based on secured funding by a developer for its own activities.

Some respondents proposed that GNI could conduct its own risk assessment of each connection project. GNI does not conduct such assessment currently and it is not considered practical to introduce such an approach. It is considered that on balance there are more practical alternatives, discussed later, that will provide a better alignment of the financial security requirements with the actual risks to the gas network. These alternatives would also avoid further complexity, cost and potential room for discretion by introducing a requirement on GNI to carry out a detailed and individual risk assessment for each connection, which would take a significant time (and cost) to introduce.

### Distinguishing between financial security requirements during construction and operation and the treatment of the BNEF

The CRU agrees with the views of a number of respondents that the risk during the construction phase is greater than during the operational phase. A key exception to this is the cost associated with the BNEF.

In its original submission to the CRU, GNI did consider the removal of the BNEF from the financial security requirements. That was on the grounds that the BNEF is a standard component that could, in principle, be relocated and used for a different biomethane connection. However, GNI emphasised that relocation can present challenges and that, in practice, the BNEF should be considered a stranded asset in the event of a biomethane connection failing after it has been installed.

However, as pointed out by some respondents, the stranding risk associated with the BNEF is substantially lower during the construction phase. GNI has indicated to the CRU that there is a lead time of several months between when the contract is signed with the connecting party – and the financial security requirement starts – and when the BNEF is delivered on site. During this time, if any issues arose that would prevent the connection from becoming operational, GNI could store the BNEF and use it for a different biomethane connection. In other words, the stranding risk associated with the BNEF is much lower during the construction phase than it is during the operational phase.

In recognition of the difference risks during construction and operation, the CRU has decided to change its consultation proposal. These changes are to better reflect the risk profile during the construction and operation of the connection.

1. **Construction phase** - During construction, financial security will be required to cover all capex costs involved in the building of the connection net of upfront contributions<sup>18</sup> (i.e. the socialised cost), excluding the cost of the BNEF. Excluding the BNEF reflects the practical ability, as indicated by GNI, to redeploy the BNEF if the connection does not go ahead for any reasons.
2. **Operational phase** - During the operational phase, financial security will be required to cover 70% of the capex costs involved in building the connection net of upfront contributions. This will include the cost of the BNEF.

Phasing the requirement in this way recognises the lower risk during operation and is considered to better align the financial security requirements with the profile of risks associated with biomethane connections. Basing the requirement on a proportion of the socialised capex, rather than the volumes injected, simplified the CRU's proposal and avoids potential unintended consequences, as discussed in more detail below.

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<sup>18</sup> That is, net of the 30% standard contribution as well as any supplemental contribution required based on the outcome of the economic test.

### Capping the financial security requirements at seven years

A number of respondents proposed that the financial security requirements be removed after seven years, in line with the current arrangements. The current arrangements are based on an economic test of ten years. This sees three years of revenues captured under the economic test not being accounted in the financial security requirements. This, in practice, sees a risk sharing between connecting parties and gas customers during those three years, because the initial socialised capex of the connection may not yet have been recovered from the tariff revenues associated with the gas injected at the connection. Where issues arise during those three years there is no financial security in place if things go wrong, and the gas customer may be left having covered the cost of partially stranded connection assets. With the economic test increasing to 15 years, this so called “tail-end” risk would be increased from three to eight years. This would be a significant increase in the “tail-end” risk, which would place too much of a burden on gas customers.

In the consultation paper, the CRU presented a proposal to move away from a time-based system for financial security to one based on volumes injected. As discussed earlier, this was proposed to better align with the real risks of shortfalls in revenues, which are associated not only with time elapsed but also the volumes of biomethane injected over that time period. It was proposed in the consultation that the financial security requirements would be based on 70% of the volumes required to break even for a project under the economic test. As previously discussed, the CRU has decided to change this requirement. During the construction phase the requirement will cover all socialised costs, but exclude the cost of the BNEF. This will lead to a lower requirement for the majority of biomethane connections, since the BNEF represents a significant share of connection costs. The requirement in the operational phase will be based on 70% of the socialised capex rather than 70% of the volumes to break even as consulted upon. The period of operation for which financial security is required will no longer be limited to a maximum of seven years.

### Requests for more detail on how the volume-based requirement will be calculated

Some stakeholders requested more detail on how the proposed financial security requirement will be calculated in practice. This is provided in the next section, which sets out the CRU’s decision on financial security in greater detail, including the changes to what was originally proposed in the consultation paper.

### Stakeholder working group to co-design financial security requirements

One stakeholder recommended that the CRU convene a working group with developers, financiers, and regional stakeholders to co-design updated financial security requirements for renewable gas.

The CRU has considered in detail the views of all parties who have responded to the consultation. The responses have identified opportunities to better align the financial security requirements with the risk profile associated with a biomethane connection. The CRU considers that any potential added value of additional input at this juncture is outweighed by the benefits of implementing the changes detailed in this paper now to provide certainty and benefits to the market in terms of connection costs. The effectiveness of the updated connection policy, including the financial security arrangements, will be monitored and reviewed through the PC5 Reporting and Incentives Framework.

## **4.2.5 CRU's Decision**

The CRU has reviewed all responses received. Based on that review, the CRU has decided that the financial security requirements will be different during the construction of the asset and during its operation. This is to better reflect the different levels of risk during those phases.

During construction, financial security will be required to cover all socialised capex (that is, all costs involved in building the connection, net of upfront contributions<sup>19</sup>) and excluding the cost of the BNEF. This reflects the practical ability, as indicated by GNI, to redeploy the BNEF if the connection does not go ahead for any reasons. Once the operational phase begins, financial security will be required to cover the revenue associated with 70% of the total socialised capex, including the cost of the BNEF.

This is a change from the consultation proposal of basing the requirement on the revenues associated with 70% of the volumes required to break even in the economic test. The reason for this change is to simplify the proposed new financial security requirements and maintain a closer alignment with GNI's existing rules, while still aligning the requirements more closely to actual stranding risk. The requirement to maintain financial security for a fixed period of seven year will no longer apply.

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<sup>19</sup> That is, net of the 30% standard contribution as well as any supplemental contribution required based on the outcome of the economic test.

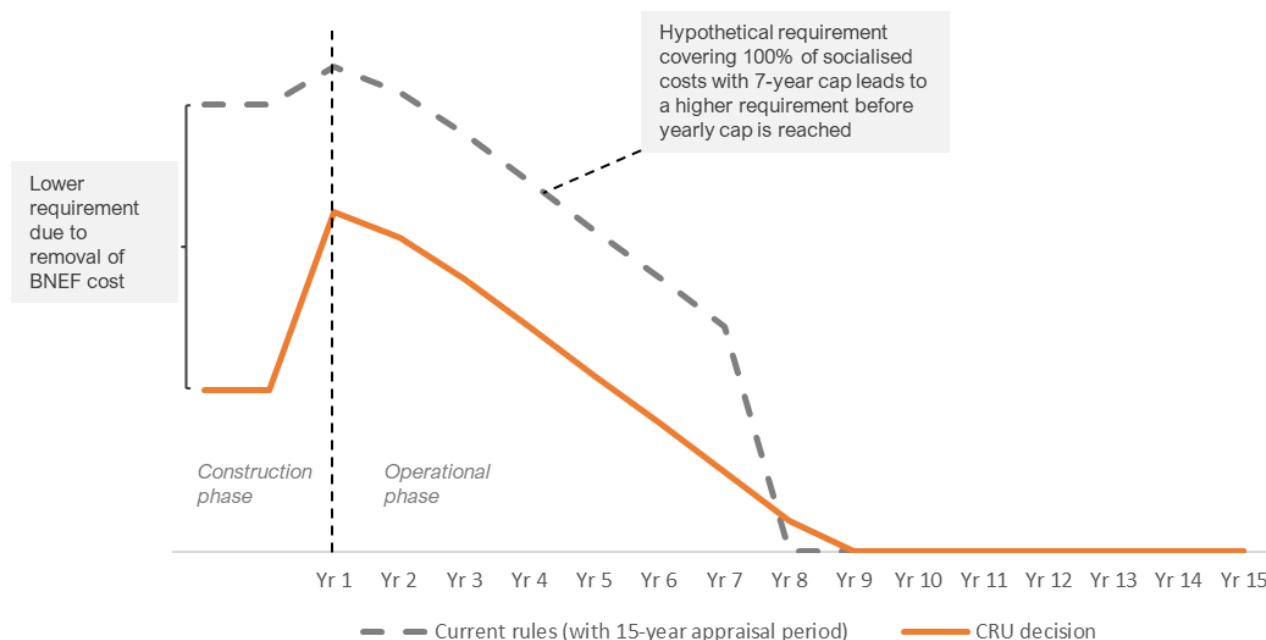
Overall, the CRU considers that this strikes the appropriate balance between protecting consumers from stranding costs and enabling easier access to the gas network for biomethane developers. This approach is also more consistent in how risks are shared between consumers and connecting parties, compared to the current time-based risk sharing arrangement.

Figure 2 illustrates the difference between the new methodology and the financial security requirements under the current methodology with a seven-year cap. In both cases, a 15-year appraisal period is used, showing the requirement for a hypothetical biomethane connection, which breaks even in the economic test at the end of the 15-year appraisal period. As shown in the figure, the exclusion of the BNEF leads to a lower requirement during the construction phase, while the reduction in the requirement from the full socialised capex to 70% of it leads to a lower requirement during the operational phase.

Taken together, the extension of the economic test appraisal period and the changes to financial security requirements discussed here should meaningfully lower the costs required to connect to the gas network for all biomethane connections. For larger connections and those closer to the existing network, these savings will be primarily driven by the reduction in financial security requirements shown in Figure 2. This is because these connections were already more likely to pass the economic test under current arrangements and will now be required to provide less financial security. While the requirement will no longer fall away after 7 years, these connections will be unlikely to take significantly longer to inject the volumes required to cover 70% of the socialised capex and should therefore face significantly lower costs overall.

For smaller connections and those farther away from the existing network, the savings will primarily result from lower upfront contributions being required as a result of the longer economic test appraisal period. While lower upfront contributions mean that a higher proportion of the connection costs are socialised, and therefore subject to financial security requirements, the net effect of both changes should still result in significant cost savings for these kinds of connections.

**Figure 2:** Source: CRU & CEPA analysis based on GNI inputs. Illustration of the impact of the new methodology decided upon in this paper for a hypothetical biomethane connection which breaks even in the economic test at the end of the 15-year appraisal period.



In practice the changes in the financial security will result in the following:

- During the **construction phase**, the connecting party will be required to provide financial security to cover all costs incurred by GNI in building the connection, with the exception of:
  - The proportion of those costs paid upfront by the developer (standard 30% contribution plus any supplemental contributions paid under the economic test); and
  - The costs associated with the BNEF.
- Since no biomethane will be injected at the connection during the construction phase, the financial security requirement will not reduce during the construction period. This will ensure that, should the connection never commence operations, GNI would be able to recover the cost of stranded connection assets.
- the financial security requirements will change once the connection becomes **operational**. Financial security will be required at the start of this phase to cover 70% of all the costs incurred by GNI in building the connection. This will include the cost of the BNEF.

Each year, the financial security requirement will be reduced by the value of the network tariff revenue associated with the volumes injected by the connecting party in that year. When the

cumulative tariff revenues are sufficient to cover 70% of the socialised proportion of capex, the financial security requirement falls away. The period of operation for which financial security is required will no longer be limited to a maximum of seven years. It is important to note that GNI can, in line with its Financial Security Policy, draw on the financial security at any time where there are issues with the biomethane connection.

#### **Decision**

Financial security for biomethane connections will be as follows:

1. **Construction phase** - During construction of the connection, financial security will be set to cover all socialised capex (that is, all costs involved in building the connection net of upfront customer contributions<sup>20</sup>) but the cost of the BNEF will be excluded.
2. **Operational phase** - Financial security will be set to cover 70% of the socialised proportion of the cost of building the connection. The cost of the BNEF will be included in this phase. The requirement will reduce in line with tariff revenue associated with the injected gas until the cumulative revenues cover 70% of the socialised upfront costs. The period of operation for which financial security is required will no longer be limited to a maximum of seven years..

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<sup>20</sup> The Connection Policy states that 'All renewable gas connections will be required to make a standard contribution of 30% of the estimated costs for the injection facility'

## 5. Central Grid Injection Facilities

A Central Grid Injection (CGI) facility enables the injection into the gas network of biomethane transported via road from plants that are located too far away from the grid for a direct connection. The National Biomethane Strategy specifically calls for smaller, dispersed biomethane plants to be given access to grid injection through CGI facilities. GNI proposed to build its first CGI facility in Mitchelstown, Co Cork, with the expectation of more facilities of this type being built at other points on the transmission network in the future. Two CGI facilities owned and operated by GNI were accounted for in the CRU's PC5 decision. The CRU made it clear in this decision that CGIs should be treated as connection assets and that the same connection policy should apply to biomethane producers whether they inject gas through a direct connection or via a CGI facility – i.e. 30% of the connection costs would be charged directly to the connecting parties. CRU consulted on proposals from GNI on how the 30% contribution would be allocated to each party in a multi-user facility like the Mitchelstown CGI and this paper sets out the CRU decision following on from that process.

### 5.1.1 Consultation Proposals

The CGI at Mitchelstown is a regulated facility and is the first of its kind in Ireland. It allows multiple parties to use this facility under a long-term agreement, with each party having their own individual arrangements with a shipper of their choosing. GNI proposed that the connection charges for the CGI would be allocated to the connecting parties similar to the approach to group appraisals <sup>21</sup> under the current connection policy. This would see:

- the 30% customer contribution allocated on a pro rata basis, in line with contracted for capacity;
- cost allocation and financial security requirement would be based on the entire cost of the CGI;
- GNI would bear the risk of any future phases (beyond phase 1) until their full capacity is contracted and the full proportion of capacity is recovered from customers.

GNI is pursuing a phased approach to the construction of the first planned CGI facility at Mitchelstown. The first phase would result in an injection capacity of 175GWh per year,

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<sup>21</sup> Group appraisals see multiple parties connecting on the same “corridor” being considered as a group / in aggregate and costs allocated based on their relative load / distance

increasing to 700GWh per year when the facility is fully operational. This phased approach means that GNI will substantially complete the fixed civil works for the entire facility as part of the phase one construction rather than developing them over each phase. This has the benefit of reducing the overall costs through lower labour costs and avoiding undoing some earlier work at a later stage to facilitate the expansion project. It will result in the first phase incurring around half of the entire capex costs despite providing only a quarter of the full injection capacity.

The CRU asked for stakeholders' views on the following questions in the Consultation regarding CGI connection charges and phasing and the future delivery of CGI facilities–

*Question: Do you agree with the proposal that connection charges for the Mitchelstown CGI will be allocated pro rata based on contracted for capacity? Do you agree that this will be done based on the cost of the entire CGI but that GNI will only include the cost of future phases onto the RAB once they are fully contracted for (i.e. phase 2)?*

*Question: Do you agree with the requirement for GNI to assess, with stakeholder input, the delivery of CGIs under a developers' choice model?*

## **5.1.2 Summary of Stakeholder Responses**

The following is a brief summary of the stakeholder responses to the CGI questions posed in the consultation. A more detailed review of the responses can be found in the Appendix at the end of this paper.

Most of the respondents expressed views on the broad concept of a centralised grid injection facility, with almost all supporting the CGI connection charges proposals.

A number of respondents stated that all developers should be treated fairly and equitably regardless of the method in which they inject biomethane, and users of the Mitchelstown facility should be subjected to the same connection costs as those with a direct connection.

Several respondents agreed that the pro rata cost allocation for the Mitchelstown CGI should be based on the cost of the entire CGI, to ensure that first-movers are not at a disadvantage to those who contract later. GNI stated that CGI users should be treated as a group for appraisal purposes, with evergreen contracts providing long-term access and operational certainty.

One respondent discussed the need for clear timelines from GNI on the second phase of development at Mitchelstown. Another suggested GNI should allow temporary access to the CGI for those waiting for a direct connection.

Stakeholders also submitted their views on the assessment of future delivery of CGI facilities under a developers' choice connection model, with almost all respondents agreeing with the

proposal. Most responses addressed the availability of a developer's choice model for all biomethane connections in general, not specifically CGIs. Several commented on the significant cross-European experience among the biomethane developer community in Ireland and noted the expertise available across Europe and the UK that could be rapidly transferred to Ireland. Some respondents spoke about the importance of the learnings that will accrue from Mitchelstown once it becomes fully operational and noted how these would be important for any assessment of future CGIs. Others suggested the establishment of a structured stakeholder forum to guide the CGI assessment process and establish transparent criteria for assessing delivery under a developers' choice model. A small number of respondents addressed the issue of contestable works, with one stating that allowing developers to execute the delivery of the gas connection would help to reduce cost and delivery risk. One respondent stated that a strategic asset like a CGI would operate more efficiently with less complications if it was owned and operated by GNI under the maximum model.

GNI noted the PC5 decision to deliver the first two CGIs under the maximum model and stated that once these have been delivered they would welcome further engagement with CRU on the delivery of any further CGIs under a developers' choice model.

### **5.1.3 CRU's response**

The CRU notes that there was broad acceptance from stakeholders to the CGI connection and phasing questions in the Biomethane Connections Policy Review consultation process.

The CRU notes that the proposed configuration of the CGI at Mitchelstown is novel and the first of its kind in Ireland and is designed to allow multiple parties contract for firm capacity with their own shipper. The proposal to allocate costs on a pro-rata basis, based on contracted for capacity, is similar to that for group appraisals and would avoid creating a first-mover disadvantage for those connecting in the first phase of the facility who would otherwise face higher injection charges than those connecting in the second phase.

The CRU also notes that applying the same financial security requirements as those for a direct pipeline connection ensures that consumers are protected against any stranding risk of CGI facilities. This ensures consistency in connection charging approaches between those using the Mitchelstown CGI and those with direct connections, mitigating the risk of incentive distortions between the two.

The CRU notes that one respondent suggested that GNI should provide a clear timeline and criteria for triggering the second phase of development at the Mitchelstown CGI and should consider a capacity reservation mechanism that allows developers in early stage of development

to secure future capacity at the second phase. Another respondent requested that provision should be made to accommodate temporary access to the CGI for biomethane plants awaiting the completion of a direct grid connection, to allow biomethane production and injection to commence in the interim. Both of these proposals would go beyond what is available for direct connections and could see the use of network assets being allocated to projects that have not provided financial security requirements, which would not be seen as appropriate.

GNI's proposal would see them take on the risk that, in the event of the second phase being delayed, cancelled or not fully subscribed, the standard contributions and financial security obtained from connecting parties would only cover about half of the costs of the first phase.<sup>22</sup> GNI would bear this temporary risk itself, until the assumed full capacity of the CGI is contracted and the full proportion of capex is recovered from customers in future years. As the project is developed to completion and contracted, the amount of temporary under-recovery would reduce until the full capacity is contracted.

On balance the CRU consider these arrangements are appropriate but should be kept under review, recognising that this is a first of its kind in Ireland. As part of the consultation CRU asked if GNI should be required to carry out an assessment, with stakeholder input, on its approach to any future CGIs delivered by GNI under a developers' choice model. The CRU notes the widespread opinion expressed in the consultation responses that the developer's choice model should be available in Ireland for all biomethane connection types and the view expressed by some respondents about the importance of using the Mitchelstown experience to guide the readiness of the market for the minimum connection and developer's choice model.

Some respondents noted the benefits of contestable works. Contestable works could see parties building a connection and then handing it over to GNI to form part of its network and are beyond what a minimum connection model would provide. Under a minimum model, anything built by the connecting parties would not be part of the network. A consideration of contestable works is not in the scope of this review.

### **5.1.4 CRU's Decision**

The CRU considers that the cost allocation proposals presented by GNI are consistent with the treatment of traditional pipeline connections and would avoid creating a first-mover disadvantage for those connecting in the first phase of the facility. This is aligned with the PC5 decision, which

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<sup>22</sup> Since the first phase accounts for 25% of total injection capacity but 50% of total costs, GNI would be taking on the risk for the remaining 25% of total costs, or half of the first phase costs.

concluded that CGIs should be treated as connection facilities, and that the same connection policy should be applied to producers injecting at these facilities and at direct pipeline connections. The CRU also notes that applying the same financial security requirements as those for a direct pipeline connection ensures that consumers are protected against any stranding risk of CGI facilities. This approach ensures consistency in connection charging approaches between those using the Mitchelstown CGI and those with direct connections, mitigating the risk of incentive distortions between the two. The CRU has therefore decided that the CGI charging and cost allocation arrangements proposed by GNI in the biomethane connections policy review consultation are appropriate and pragmatic and should apply to the Mitchelstown CGI.

The consultation paper asked the question whether GNI should carry out an assessment, with stakeholder input, on its approach to any future CGIs delivered by GNI under a developers' choice model. The CRU considers this approach as appropriate. GNI should engage with stakeholders on this topic and how best to structure input into its review and the best time to carry it out. PC5 set out the maximum connection model would be adopted and that GNI would table proposed options for the transition to a developers' choice model. CRU placed incentives on GNI to progress this work. The CRU will consider the timing of the transition in the 2027 CRU Workplan and progress in this regard will also be evaluated on an on-going basis through the PC5 implementation framework. The CRU expects that the proposed options would cover how the CGI will be treated under a developer's choice model

### **Decision**

The CRU has decided to implement the changes proposed in the consultation and this will see:

- Cost allocation and financial security requirements being based on the entire cost of the CGI
- Connecting parties will contribute to 30 % of costs on a pro rata basis, in line with contracted for capacity

## 6. Decision and Next Steps

Following a detailed review of all responses received the CRU has decided that:

- the appraisal period for the economic test for biomethane connections will be extended to 15 years
- the financial security requirements for biomethane connections will be set as follows:
  - **Construction phase** – during construction of the connection, financial security will be required to cover all connection costs net of upfront customer contributions, excluding the cost of the BNEF.
  - **Operational phase** – during the operational phase, financial security will be required to cover 70% of the capex costs involved in building the connection net of upfront customer contributions. This will include the cost of the BNEF. The financial security requirements will reduce in line with tariff revenue from injected gas until the cumulative revenues cover 70% of the socialised upfront costs.
  - The period of operation for which financial security is required will no longer be limited to a maximum of seven years.
- Connection charges for the CGI will be allocated to connecting parties similar to the group appraisals approach under the current connection policy.
- The customer contribution of 30% of the CGI cost will be allocated on a pro-rata basis, in line with contracted capacity
- To avoid first-mover disadvantage, the cost and financial security requirement of the entire CGI will be included in calculating the connection contributions payable by any connecting party regardless of what phase they connect in
- GNI will bear the risk of any future phases of development of the CGI until the full capacity is contracted and the full proportion of capacity has been recovered from customers

Further to the decisions discussed in this paper GNI will update the Gas Networks Ireland Connections Policy Document and any other relevant documents. The CRU have engaged with GNI on the modifications to the Code of Operations required to implement these decisions and the Code of Operations will be updated when that process has been completed. The CRU will monitor and review the effectiveness of the updated policy through the PC5 Reporting and Incentives Framework to ensure it continues to meet the requirements of the biomethane industry.

## Appendix – Stakeholder Responses to Consultation Questions

The CRU received responses from 27 stakeholders in relation to the questions presented in the Biomethane Connections Policy Review Consultation, and all respondents are thanked for their comments and feedback. The responses can be viewed on the CRU Consultation Portal<sup>23</sup>. Most responses are published in full, but two have been redacted in part as requested. One respondent requested that their submission remain confidential, and this has not been published. A list of the respondents is presented below, followed by a summary of the responses.

### **Respondents**

|                          |
|--------------------------|
| BioCore Environmental    |
| Bord Na Mona             |
| BOS Energy               |
| Captured Carbon          |
| Carbon AMS               |
| Clarke Energy            |
| CNG Services Ltd         |
| Cork Chamber             |
| Cycle 0                  |
| Energia                  |
| ESB Generation & Trading |
| Fingleton White          |
| Flogas Ireland           |

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<sup>23</sup> [CRU Consultation Portal](#)

|                                                   |
|---------------------------------------------------|
| Gas Networks Ireland                              |
| Green Gas AD                                      |
| Greengate Biogas                                  |
| Greensource                                       |
| Grissan Renewable Energy                          |
| Irish Bioenergy Association (IrBEA)               |
| Irish Creamery Milk Suppliers Association (ICMSA) |
| Irish Farmers Association (IFA)                   |
| Irish Farm Accounts Cooperative (IFAC)            |
| Local Power                                       |
| Nephin Renewable Gas                              |
| Renewable Gas Forum Ireland (RGFI)                |
| Rockbrook AD                                      |
| South East Energy Agency (SEEA)                   |

## **Summary of Responses**

### **Economic Test**

*Question: Do you agree with the proposal to extend the appraisal period for the economic test from 10 to 15 years for biomethane connections*

There was almost universal support from respondents for the proposal that the economic test period should be extended beyond 10 years, although there were different views on how long the extension should be. Some respondents supported extending the appraisal period to 15 years as proposed, but the majority noted that an extension to 20 years would be more appropriate. One respondent stated that precedent for a 20-year appraisal period exists within the gas connection policy for institutional industrial and commercial connections, where a tiered approach is taken. A number of respondents commented on the importance of striking the right balance between the

financial obligations being placed on biomethane developers and maintaining appropriate safeguards for consumers.

Several respondents noted that the current 10-year period was significantly below the expected operational life of a biomethane plant, with one noting that it was less than the demonstrated track record for biogas and biomethane plants elsewhere in Europe. Another stated that biomethane projects are highly capital-intensive with long payback periods.

A number of respondents noted that increasing the appraisal period would reduce costs for biomethane developers by reducing or eliminating the supplemental contribution, directly incentivising more projects and a greater diversity of supply. Several stated that extending the period to 15 years would significantly reduce upfront costs and would encourage a wider geographic spread of AD plants, leading to facilitating greater participation by smaller, farmer-centric projects, consistent with the National Biomethane Strategy.

Some respondents commented that the reduced upfront costs would extend the distance from the gas grid where a connection is likely to pass the economic test, increasing the number of viable AD projects nationwide. One respondent quoted from their own experience where projects located more than 5km from the gas grid often end up with a significant supplemental contribution and stated that several otherwise attractive projects in their development pipeline are currently on hold. In their opinion, extending the appraisal period would help unlock and accelerate these projects, along with many others across the country.

Several respondents who favoured extending the appraisal period for the economic test to 20 years commented on the significance of the forthcoming Renewable Heat Obligation (RHO), with one noting that it will provide long-term policy certainty that extends beyond 15 years, reducing stranding risk significantly. Another said that national policy instruments such as the RHO provide long-term visibility on demand that materially reduces stranding risk over the coming decades.

GNI agreed with the proposal to lengthen the economic test appraisal period to 15 years as it would increase the potential number of biomethane plants connecting to the gas network by extending the distance that a plant can be located from the gas network without incurring a supplemental contribution. GNI considered that it provides a more comprehensive and realistic assessment of the economic viability of biomethane projects as a longer appraisal period allows for the cost of connections to be recovered over a longer time horizon, reduces the number of customers who will have to pay a supplemental charge and allows customers more distant from the network to connect. Extending the appraisal period to 15 years also aligns well with international best practice.

## Financial Security

*Question: Do you agree with the proposal to set the financial security requirements based on 70% of the injection volumes to break even under the economic test?*

There was a wide range of responses on the proposal to base the financial security requirements at 70% of the break-even injection volumes as set in the economic test.

A small number of respondents favoured retaining the current time-based approach to financial security. One pointed out that the proposed change to a volume-based approach could result in higher and longer-lasting security obligations for producers, which could potentially act as a deterrent to potential investors. GNI also favoured keeping the current approach, stating that requiring customers to hold financial security for a period of seven years, or until the required volume is delivered, is important due to the relatively new nature of the renewable gas market in Ireland and the current limited supports for the sector. GNI was concerned that the proposal to base financial security on 70% of projected volumes may create too much of a deterrent to new investment, believing that the cost of the financial security for the producer may increase if the current period of seven years is not considered as a cap as part of this proposal and that this cost could be greater than any benefits arising from an increase of the appraisal period for the economic test.

Several other respondents supported the proposal to base the financial security requirements at 70% of the break-even injection volumes. One noted that it complemented the proposed increase in the economic appraisal period and balanced the risk between the developer and the system operator. Another said that changing from a time-based to a volume-based requirement for the financial security would allow those developers with security of feedstock supply to be more ambitious in their volume forecasts, making it more likely they would meet the requirements of the economic test and reduce their financial security. Some respondents noted that requiring 70% of the break-even injection volumes to be achieved was excessive and suggested that a lowering of the percentage requirement to 50% or below should be considered.

A number of respondents who supported the proposal in principle suggested that it could be improved by a two-stage approach to financial security, with a difference being drawn between the construction and operational phases reflecting the different risk profiles in these stages. One noted that the current financial security requirements start prior to revenue generation by including both the construction and ramp-up phases. Another stated that the financial security

requirement should only apply to the construction phase as this is when there is the greatest risk to the connection.

A substantial number of respondents disagreed with the proposal, with some stating that no financial security of any form should be required. Several described the financial security requirement as a significant barrier to market entry for biomethane developers and a deterrent to potential investors. One said this requirement was a cash outflow for developers, particularly for those who must post financial security by way of a demand deposit and noted that this is very penalising for developers as the highest level of financial security coincides with the capex outlay for the plant construction. Another respondent disagreed with the current and proposed approaches to financial security as both require large amounts of capital to be locked up for many years in the provision of guarantees.

Several respondents noted that biomethane projects will not receive funding from backers or financiers unless certain conditions such as full planning permission, feedstock supply agreements and contracts, and offtake agreements like gas purchase agreements are agreed and in place. They argued these should provide enough evidence of financial stability, eliminating the need for any additional financial security. Others said that there should be no need for additional financial security on the basis that biomethane projects go through robust due diligence checks before finance is secured for the projects to progress and this should provide enough evidence of financial security and eliminate the need for any financial security.

Some respondents noted that the requirement is particularly onerous on smaller market participants, with one stating that the policy being proposed would make biomethane viable only for large scale developers who can receive letters of credit or guarantees for the financial security requirements while leaving behind a cohort of smaller developers, farmer co-operatives and communities who wish to get involved in the biomethane sector. One respondent said that the financial security requirements will disproportionately impact small to medium-sized biomethane developments, undermining the "agri-led, farmer-centric model" envisaged in the National Biomethane Strategy. Another respondent said that the cost faced by smaller entities in financing the security requirements over the construction and operational period would be significant and would make some biomethane projects extremely difficult to finance. Another discussed the risk that some plants would opt for simple biogas production for CHP heat and electricity production due to the additional large capital and operational expenditure involved in upgrading to produce biomethane on top of already significant AD plant capital costs.

A number of respondents expressed the opinion that the financial security mechanism is based on a gas connections policy that was primarily designed for demand customers rather than gas generators and noted that while financial security requirements are an established instrument for demand customers, they are not appropriate for gas generators like biomethane plants. One noted that biomethane facilities as long-term suppliers of gas are intrinsically tied to the gas network, in contrast to demand connections which may cease gas usage or switch to alternative energy sources over time. Some respondents noted that the biomethane network entry facility (BNEF), which makes up a significant proportion of the connection costs, is a modular and relocatable piece of equipment that could be redeployed elsewhere in the event of a plant failure, materially reducing the risk of stranded network assets and as such it should not be included in the financial security requirements.

Some respondents suggested that VAT should be excluded from the financial security calculation during the pre-operational stage, noting that this would meaningfully reduce the financial security burden on developers.

One respondent commented on the level of risk that should be acceptable in the context of the overall benefit to society of achieving the Climate Action Plan target of 5.7TWh biomethane by 2030, saying that it was not unreasonable for consumers to take on more of the risk associated with building biomethane connections as this risk would be socialised through future tariff adjustments to recover any loss of connection cost payments. Another respondent also commented on risk, noting that the consultation paper does not contain any analysis on the risk profile of biomethane projects or rate of failure of projects/developers in Europe to justify the proposed approach to financial security.

It was suggested by one respondent that the list of available financial security instruments should be widened to take account of stronger counterparties. For example, it was pointed out that under the current financial security policy a parent company guarantee can only be provided by a rated entity, and the cost of obtaining a rating could be higher than the cost of the financial security itself.

Some respondents believed insufficient cost figures, worked examples and analysis were presented in the consultation paper and requested more detail about how the financial security requirement would be calculated under the % volume approach. One stated that the financial cost implications of the consultation proposals should be further discussed and evaluated by the CRU in consultation with industry stakeholders prior to the policy being finalised.

Another recommended that the CRU convene a working group with developers, financiers, and regional stakeholders to co-design financial security requirements that are fit for purpose for

renewable generation. This would involve a comprehensive cost-benefit analysis of the proposed financial security requirements, including impact on sector development and consumer costs, consider international best practice from EU states with established biomethane sectors and should recognise the potential of long-term offtake agreements as equivalent security.

### **CGI Charging Arrangements and Cost Allocation**

*Question: Do you agree with the proposal that connection charges for the Mitchelstown CGI will be allocated pro rata based on contracted capacity? Do you agree that this will be done based on the cost of the entire CGI but that GNI will only include the cost of future phases onto the RAB once they are fully contracted for (i.e. phase 2)?*

Most of the respondents expressed views on the broad concept of a centralised grid injection facility, with almost all supporting the CGI connection charges proposals.

A number of respondents stated that all developers should be treated fairly and equitably regardless of the method in which they inject biomethane, with one noting that developers who use the Mitchelstown facility should be liable for the CGI development costs in the same way developers utilising direct injection are liable for connection costs. Another stated that they supported the proposals as they ensured a level playing field for biomethane producers whether they have a direct connection or use a CGI and they considered the proposed approach to cost recovery for the phasing of the Mitchelstown CGI to be pragmatic.

Several respondents agreed that the pro rata cost allocation for the Mitchelstown CGI should be based on the cost of the entire CGI, with GNI bearing the risk of future phases until the facility is fully contracted. Some respondents pointed out that this approach would ensure that first-movers are not at a disadvantage to those who contract in the second phase of the development. One respondent noted that by sharing connection costs on a pro-rata capacity basis, the Mitchelstown CGI provides a practical route-to-market for dispersed biomethane plants, ensuring that smaller, agri-led projects are not unfairly penalised by their size or location. Another respondent stated that an alternative cost basis would be preferable and suggested that the cost basis should be based on the entire CGI and its future phases minus the portion of costs covered by the climate action fund.

One respondent suggested that GNI should provide a clear timeline and criteria for triggering the second phase of development at the Mitchelstown CGI and should consider a capacity reservation mechanism that allows developers in early stage of development to secure future capacity at the second phase. Another respondent felt that provision should be made to accommodate temporary access to the CGI for biomethane plants awaiting the completion of a direct grid connection, to allow biomethane production and injection to commence in the interim.

Another suggested that consideration should be given to the distance a producer may have to travel to inject their gas at the CGI, with higher transportation costs being incurred over time by those with longer journeys to the facility. Another respondent stated that CGI facilities should be deployed in strategic areas with a high biomethane potential and the likelihood of a significant number of smaller AD plants being developed.

GNI agreed that connection charges for the Mitchelstown CGI should be allocated pro rata based on contracted capacity, noting that CGI facilities are designed to serve multiple producers, in a shared infrastructure model that promotes efficiency and inclusivity. They stated that CGI users should be treated as a group for appraisal purposes, with evergreen contracts providing long-term access and operational certainty, stating that this model is in line with the current GNI Connections Policy and the CRU's PC5 decision that 30% of the capital costs of CGI connections are recovered from the customer. They note that it also supports the development of dispersed biomethane plants and aligns with the National Biomethane Strategy's emphasis on decentralised production.

GNI stated that the cost of the CGI should be apportioned pro rata based on the capacity allocated. They also said that, as the CGI is developed in phases and to avoid first mover disadvantage, the cost of the entire CGI should be included in calculating the connection charge to be allocated to any connecting party regardless of what phase they are in.

### **Future Delivery of CGIs under a Developers' Choice Connection Model**

*Question: Do you agree with the requirement for GNI to assess, with stakeholder input, the delivery of CGIs under a developers' choice model?*

Almost all respondents who expressed a view on this question agreed with the proposal. Most responses addressed the availability of a developer's choice for all biomethane connections, not specifically CGIs. One respondent noted the difficulty in reaching the 2030 target if the maximum approach remains the only option available.

A number of respondents mentioned the efficiency and cost benefits associated with a developers' choice connection approach. One stated that exploring alternative delivery models would give developers the freedom to choose what approach is best suited to their project and reduce delivery costs. Another noted that the developers' choice model would foster transparency and competition in delivery and would mirror the collaborative planning seen in other biomethane markets where network operators and financiers work closely with producers to expand connections in ways that reduce upfront costs and support project financing. Another noted the benefits of having the same

contractors who provide the equipment to purify and upgrade biogas into biomethane also providing the equipment to inject the gas into the grid.

Several respondents commented on the significant cross-European experience among the biomethane developer community in Ireland and noted that the developers' choice approach has been successfully deployed in other jurisdictions. One said that while there may be limited experience in Ireland there is plenty available across Europe and the UK and that expertise could be rapidly transferred to Ireland, drawing in Irish contractors to deliver the services and leading to the development of an indigenous technical skill base. Another respondent with experience of the minimum model in the UK biomethane sector noted that competition increases efficiency, with projects being delivered at both a lower cost and in a shorter timescale than those developed wholly by the network operators.

One respondent stated that the default option for strategic CGI's intended to service many individual and independently owned AD plants should remain as the maximum approach. They stated that the minimum model could face complications regarding ownership and operation of the BNEF, which would be eliminated and operation improved if the CGI was owned and operated by GNI.

Some respondents spoke about how the learnings from Mitchelstown should be taken on board in any assessment of future CGIs. One stated that time should be allowed for this facility to become fully operational and generate meaningful design and operational data before any changes to the current CGI model are put in place. Another respondent suggested the establishment of a structured stakeholder forum to guide the CGI assessment process, ensuring consistency and accountability and leading to the development of transparent criteria for assessing delivery under a developers' choice model. Another suggested that a pilot phase for developers' choice CGIs could be implemented to test the model, gather feedback, and refine processes before full-scale rollout.

A small number of respondents addressed the issue of contestable works, with one stating that it would be helpful to assess the potential for contestable delivery of some or all gas connection infrastructure, noting that contestable delivery of electricity connections is well established in Ireland and is allowed for gas connections in many EU member states. They said that allowing developers to execute the delivery of the gas connection would help to reduce cost and delivery risk. Another respondent with UK experience suggested that a self-lay option covering only the laying of the pipeline could be considered.

GNI noted the PC5 decision to deliver the first two CGIs under the maximum model and stated that once these have been delivered they are not opposed to an assessment of the delivery of

any further CGIs under a developers' choice model and would welcome further engagement with CRU on this matter regarding what such an assessment would entail, the stakeholders involved and the decision-making criteria to be used in such an assessment.