Ongoing tariff reform at the TSO-level in Iceland

Prepared for Landsnet

AFRY
ÅF PÖYRY

Rapport

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AFRY Consult AS
Lille Grensen 5

N-0159 Oslo
Norway

Registered office in Norway
Corp. id: 934948262
VAT: VAT

afry.com

Table of content

1 Introduction and suggested changes

The aim of this report is to give stakeholders a status of the progress on the tariff reform, which Landsnet initiated a few years ago. In an earlier phase of the project, AFRY identified six priority areas:

1. Share of transmission costs recovered from producers
2. Customer categories
3. Ongoing fee
4. Basis for calculating the capacity charge
5. Targeting of connection fee
6. Procurement of system services

The fifth priority area (targeting of connection fee) was addressed via a change in network code in 2018 (introduction of a shallow connection fee). Since 2019, AFRY, together with Landsnet, have been focusing on:

- Share of transmission costs recovered from producers
- Customer categories
- Basis for calculating the capacity charge

The progress are summarized in this report. In short, we (AFRY) suggest the following changes:

- Customer categories: We suggest to divide the group of power intensive units (PIUs) between PIUs up to 30 MW and 6000 hours in capacity factor, and those above. We are currently gathering data which will allow us to test whether the lower limit of 80 GWh should be changed.
- Basis for calculating the capacity charge. We suggest changing from the current model to a model looking at consumption during the system peak. To provide long term incentives, we suggest looking at the consumption during the peak hour over a certain number of years. For generation, we suggest a model based on subscribed capacity.
- Share of transmission costs recovered from producers. We suggest increasing the share of transmission costs recovered from producers. Landsnet is currently allocating network costs to different user groups. This analysis will form the basis for the share of the revenue-cap that will be allocated to producers.

Beyond these three customer categories, we will still need to review the ongoing fee and the procurement of system services. The former will be done when we have an indication from Landsnet on which changes they foresee to implement in the three areas described above, as they are interlinked. On the latter, AFRY has started mapping system services in Iceland and abroad. Recommendations will be shared at a later stage with Landsnet and the stakeholders.

We take the chance to thank the stakeholders for the feedback we have received so far.

2 Introduction

2.1 Background for the project

Appropriate transmission tariff arrangements will:

- Contribute to utilising the existing transmission network efficiently,
- Lead to an optimal expansion of the transmission network, and
- Keep transmission network costs down.

Together with a high level of security of supply, these will contribute to economic growth and competitiveness at a national level.

In light of the numerous changes in consumption (such as more active final customers) and supply (such as distributed energy supply) sides, several European transmission system operators (TSO) have initiated a review of their tariff arrangements to ensure that they contribute to the overall objectives listed above. This is for example the case in Norway and Sweden. A similar review was launched in Iceland by the TSO Landsnet.

2.2 Tariff design

Key principles of optimal tariff design are defined in a number of publications. Examples of relevant recent publications for this project are the European Clean Energy Package[1] with EEA relevance, as well as the recent ACER report[2] on transmission tariff methodologies in Europe.

Article 18.2 of the Clean Energy Package is particularly relevant: "*Tariff methodologies shall reflect the fixed costs of transmission system operators […] and shall provide appropriate incentives […] over both the short and long run, in order to increase efficiencies, including energy efficiency, to foster market integration and security of supply, to support efficient investments, […].*"

This text is important in that it implies (i) connecting the tariff structure to the network cost structure and (ii) provide incentives over both the short and long run to increase system efficiencies. Pursuing the review of relevant documents, the following concepts become common:

- Cost-recovery - entails the ability of the network company to recover its costs in the short and long term,

[1] Official Journal of the European Union (2019), "Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity"

[2] Agency for the Cooperation of Energy Regulators (2019), "Practice report on transmission tariff methodologies in Europe"

- Cost-reflectivity - identify a tariff structure which reflects the costs different users are responsible for in the network, and promote long-term efficiency,
- Non-discriminatory - develop technology-neutral tariffs that avoid over-incentivizing some technologies to the detriment of others, and
- Transparency – develop a transparent tariff structure.

In addition, we can add robustness, which is about having a tariff that is robust to changes. These principles do however not imply that there is an ideal tariff structure which will suit every country. It is essential to take into account particular local conditions (production technology, type of customers, need for security of supply, uniform pricing, etc.), as well as the whole set of terms for grid connection access (connection policy, access rights, etc.) when designing tariffs.

We thus recognize the need for trade-off between key principles, for example that tariffs should ideally be both "cost reflective" (to encourage efficient behaviour) and "non-discriminatory" (fair cost recovery, including who should pay charges: all users or just consumers). This is also a key aspect of the ACER (2019) report mentioned earlier which claims that "*In practice, it is difficult to meet all of the principles simultaneously to their full extent. Therefore the [*body in charge of fixing or approving transmission tariffs or their methodologies, or both*] should aim to achieve a balance between these principles and sometimes they have to make certain trade-offs according to their priorities, while also respecting the legal boundaries*".

The risk of having suboptimal tariffs is that some network users end up subsidizing other network users. This entails wrong incentives, which is likely to result in a suboptimal development of the transmission network in the long run. In turn, it will result in higher transmission costs over time. In itself, this can produce adverse effects, such as reduced competitiveness of the electricity network over other energy sources and possibly some users choosing to opt-out from the system (which would imply a need to recover the total cost from fewer users, hence leading to higher prices per unit of energy transported).

As a result, tariffs should be reviewed on a regular basis, to take into account technology development or changes in consumption or production patterns.

2.3 Description of current tariff arrangements

This section is based on Landsnet's tariff for the transmission of electricity and ancillary services no. 38 (effective as of October 1st 2020)[3]. Tariffs are split between in-feed (producer) and out-feed (consumption).

2.3.1 In-feed

In Iceland, producers connected at the transmission level pay a delivery charge. At the moment, this delivery charge consists of a lump-sum of ISK 6.346.925 per year per connection point.

For in-feed at the distribution level, the distribution system operator (DSO) is charged out-feed charges. These fees vary according to the size of the power plant (article 8.1):

- No out-feed charge for power plants under 1,42 MW
- Proportionally increasing out-feed charges up to 60% of the full out-feed charges for power plants between 1,42 and 3,1 MW, and
- 60% of the full out-feed charges for power plants between 3,1 and 10 MW.

If the electricity produced in power plants through a distribution system does not enter the transmission system, DSOs shall still pay a charge for ancillary services.

2.3.2 Out-feed

Out-feed is further split between distribution system operators (DSOs) and power intensive units (PIU).

2.3.2.1 Distribution system operators

DSOs in Iceland face a variety of charges:

- Delivery charge: ISK 6.346.925 per year
  - Rebate of 40% if maximum power out-feed is between 3-6 MW
  - Rebate of 70% if maximum power out-feed is between 1-3 MW
  - If maximum power out-feed is below 1 MW, the charge can be omitted if direct costs for the out-feed are charged
- Capacity charge: ISK 6.516.566 per MW

[3] Landsnet (2020), "Tariff for the Transmission of Electricity and Ancillary Services no. 38", effective as of October 1st, 2020.

- Energy charge: ISK 471,87 per MWh
- Charge for ancillary services: ISK 65,87 per MWh
- Charge for transmission losses: ISK 88,57 per MWh

Landsnet also operates with a separate set of tariffs for curtailable transmission connected to DSOs (network code B5[4]). The DSO pays only one delivery charge for each point of supply and for each point of delivery.

- Delivery charge: ISK 6.346.925
- Energy charge
  - If utilisation time exceeds 4500 hours/year: ISK 525 per MWh
  - If utilisation time is below 4500 hours/year: ISK 1.383 per MWh
- Charge for ancillary services is reduced by 17%
- Charge for transmission losses: ISK 88,57 per MWh.

Both DSOs and curtailable transmission qualify for a discount of 5% on the capacity charge and energy charge if the electricity is delivered to a final customer at a nominal voltage over 66 kV.

2.3.2.2 Power intensive units

PIUs face similar charges as DSOs, although tariffs are in US dollars. Current charges are:

- Delivery charge: USD 45.620 per year
- Capacity charge: USD 26.574 per MW
- Energy charge: USD 1,344 per MWh.

For PIUs, a surcharge applies if electricity is delivered at less than 132 kV (article 4.6 in Landsnet's document no. 35). For PIUs that get electricity directly from a power plant connected to the transmission system[5], the out-feed charge shall be 60% of the power intensive out-feed transmission charge. A higher discount is permitted if the PIU's out-feed is entirely reliant on energy coming from the power plant.

[4] Landsnet (2010), "*B.5 Terms for Curtailable Transmission*"

[5] In this case, the energy is not transmitted through the transmission system and the transmission system does not contribute to connecting costs of the PIU.

2.4 Previous work and need for a tariff reform

In 2017, Pöyry Management Consulting (AFRY Management Consulting) was commissioned to carry out a review of Landsnet's approach to setting transmission network fees. The first phase of the project was set around:

- The role of transmission system cost recovery in helping to ensure that there is an overall optimisation of the electricity system in Iceland
- The performance of the current arrangements for transmission fees across four objectives, which are:
  - *Efficiency* - support development and operation of economic and efficient electricity systems
  - *Equity* - ensure full recovery of allowed transmission revenue in a fair and equitable way
  - *Practicality* - maintain practical and simple arrangements with low operation costs, and
  - *Robustness* - remain suitable under a range of future uncertain developments in the electricity system in Iceland.
- Possible reforms that could address some of the issues identified in relation to the efficiency and equity of current reforms

The findings of this first phase are briefly summarized here. Findings and suggestions are partly based on the concerns and views from stakeholders in Iceland, which have been involved in the project.

In terms of **efficiency**, AFRY identified challenges related to:

(i) A focus on recovery of average costs rather than marginal costs

(ii) Little if any clear value for behaving in a way that would benefit the network, including no direct fees for generation

(iii) The use of maximum demand charges, which can encourage inefficient levels of direct connection between generation and users

(iv) The lack of transparency on cost implications of investment and operational decisions of users

(v) The lack of visibility regarding the trade-off between infrastructure costs and system operation costs, and

(vi) The lack of timely and reliable information to Landsnet on new developments of smaller projects.

When it comes to **equity**, AFRY identified issues related to:

(i) The small contribution of generation to transmission network costs

(ii) Allocation of assets to different customer groups which may no longer reflect the differences between customers in each group as power intensive units become more diverse, and

(iii) Fees which may not reflect differences in the quality of service received from the transmission network.

While we did not identify issues when it comes to **practicality**, **robustness** of current transmission tariff arrangements appears suboptimal:

(i) The closure of a large user may lead to a shortfall of revenues for Landsnet, or an increase in tariffs for the remaining power intensive units, as there is no mechanism for changing the split of costs to be recovered between customer types. The opposite is also true, as a new large customer will lead to the reduction in tariffs for other power intensive units

(ii) The emergence of intermittent generation requires reassessing price signals such as to avoid investment decisions based on incomplete information due to the fact that not all costs are reflected in current tariffs, and

(iii) The emergence of smaller power intensive units with short lead time, variable consumption and shorter commitment period also provide an indication that current customer categories are no longer fit for purpose.

These challenges do not imply that all is wrong with current arrangements. For example, they contribute to full cost recovery and they do not distort upstream or downstream retail competition. Yet, the identified challenges give a clear indication that there is room for improvement.

At the end of the project, six priority areas were identified to support a cost-efficient tariff reform for network costs in the medium to long term and avoid higher network tariffs than necessary. These were:

1. Share of transmission costs recovered from producers
2. Customer categories
3. Ongoing fee
4. Basis for calculating the capacity charge
5. Targeting of connection fee
6. Procurement of system services

2.5 Scope and structure of this work

In this document, we discuss the share of transmission costs recovered from producers, customer categories and the basis for calculating the capacity charge. The analysis of targeting of connection fee was addressed via a change in network code in 2018. The procurement of system services will be addressed later in 2021.

The transmission tariff paid by final customers is the result of a three stage process. The first stage consists of identifying allowed revenues (also known as revenue cap), then the tariff structure is set, and finally costs are allocated to the network users. AFRY's role is limited to the tariff structure.

In this report, we investigate the various priority areas. Each chapter is structured as follows:

- Description of current tariff arrangements in Iceland
- Comparison of such arrangements to those of a subset of relevant countries
- Analysis of potential adjustments, qualitatively and quantitatively, and
- Outline of a set of recommendations.

Although each priority area is presented separately, they have been studied jointly. The conclusions of different parts of the report thus impact other sections as well. This is the reason behind including the capacity charge base for in-feed as well, since we conclude later that it would be beneficial to increase the share of Landsnet's allowed revenue from producers.

3 Capacity charge base (MW)

A key concept of optimal tariff design is cost-reflectivity. Provided that the main cost driver for transmission network costs is how much capacity is needed in the network at peak, it is natural to first present findings related to the basis for capacity charge, both for in-feed and out-feed.

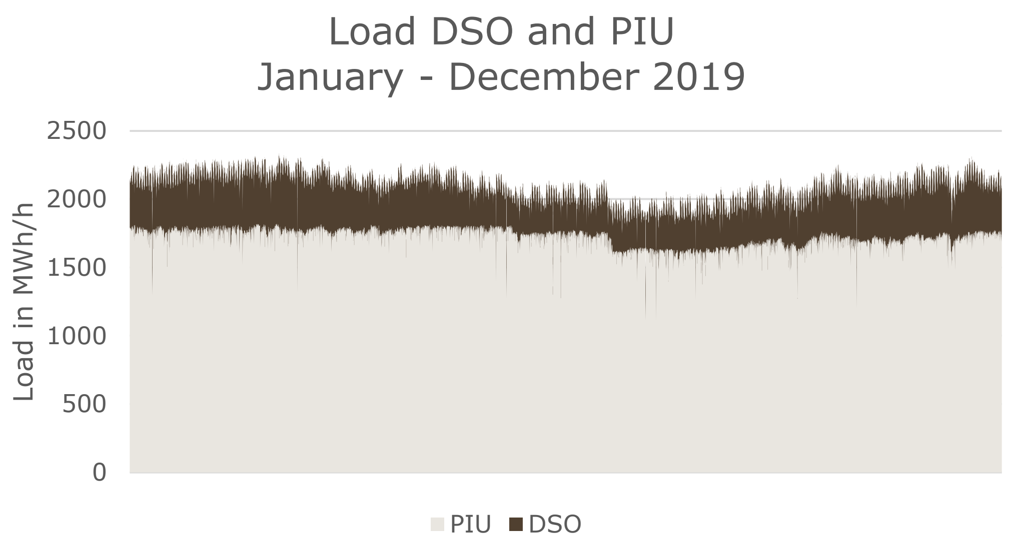
3.1 Capacity charge for out-feed

3.1.1 Situation in Iceland

The basis for the capacity charge for our-feed is measured in MW and calculated based on the average of the four highest 60-minute monthly power-peaks of the year for each delivery point. We tried to challenge this model.

We started our analysis by looking into the hourly consumption (in MWh/h) in Iceland in 2019, split between current PIUs and current DSOs. A maximum load of 2.333 MWh/h was observed, while the lowest load was measured at 1.370 MWh/h. The figure clearly indicates more variation in load for DSOs compared to PIUs over time.

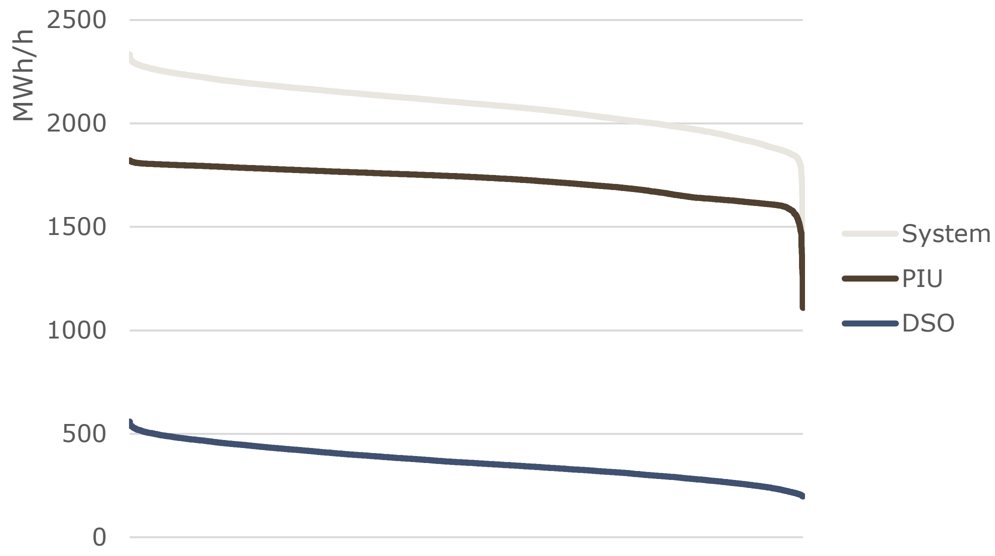
Figure 1 Hourly system load, 2019, DSOs and PIUs



Source: AFRY analysis on data from Landsnet

Another way of visualising differences in load between type of out-feeds is by looking at the load duration curve, which ranks every hour from the highest load to the lowest load.

Figure 2 Load duration curve, 2019, System, DSOs and PIUs



Source: AFRY analysis on data from Landsnet

The highest load (peak) is typically what defines investments in the electricity network. If we remove the hundred hours with highest load in Figure 2, the highest system load falls from 2.333 MWh/h to 2.083 MWh/h, or a reduction of nearly 10%. The need for network is hence reduced. This demonstrates, if necessary, that consumption impacts the system differently depending on whether it happens at a time the network is highly utilized (signals to invest) or when the system is not (no signal to invest in new capacity). It becomes doubly relevant, when considering the fact that capital costs are the main driver for network tariffs.

The cost structure should be reflected in the tariff model in order to provide appropriate long-term price signals. To establish if today's basis for the capacity charge is fit for purpose, one can consider a new customer coming to Iceland. The customer will pay a connection fee which will cover investment costs up to the nearest network connection point. We can then consider two scenarios:

(i) Our new customer takes out electricity at times when the transmission network is already heavily loaded. Landsnet will be forced to strengthen the network, a clear cost-driver.

(ii) Our new customer uses electricity when the network has available capacity and no new investment is needed in the transmission network.

For the new customer, the basis for the capacity charge is currently based on the average of its four highest 60-minute monthly power-peaks of the year, regardless of when they occur. Although it provides incentives to avoid high peak consumption, it may be poorly related to what extent the network has capacity or not to accommodate the new user. In the first scenario, other users are likely to experience an increase in tariffs, whereas they are likely to experience a decrease in tariffs in the second scenario.

In order to lower long-term tariffs, it is thus logical to use a basis for the capacity charge which encourages demand outside peak hours (contribute to a better utilisation of the electric grid and hence lower costs per unit of energy transported) and sends clear signals that consumption which increases system peaks is costly.

Before discussing alternatives for Iceland, we review current practice in other countries.

3.1.2 Practice in other European countries

3.1.2.1 Norway

In Norway, the base for the capacity charge is based on the average consumption in the highest system load hour during the last five years[6]. The highest load hour is further limited to the hour with the highest load during the period November to February. Explained differently, the basis for the capacity charge is set by looking at the hour with the highest system load during each of the last five years, identify how much each consumer was using during this hour and averaging the results over five years[7]. Users can thus influence their MW basis by avoiding peaks when the transmission network is heavily loaded. Not knowing in advance when the peak hour will occur provides incentives to avoid individual peaks in challenging periods for the transmission network. Over time, this system contributes to better utilisation time for the transmission network and reduces/postpones reinvestment needs.

3.1.2.2 Sweden

In Sweden[8], the basis for the capacity charge is an annual capacity subscription. It is possible to exceed the subscribed capacity (subject to approval by the TSO) by entering a temporary subscription. Exceedance without a temporary subscription leads to an exceedance fee. This system provides incentives to avoid peaks, which limits reinvestment needs in the transmission system. That being said, it also gives incentives to avoid peaks at times when there is sufficient capacity in the system. This may lead to a cost for the user without real benefits for the system, which is suboptimal.

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[6] Statnett (2019), ”Tariffer for transmisjonsnettet 2020”

[7] Note that the capacity base for consumption is reduced if production is available in the area, and the capacity base is further reduced for power intensive units which have certain properties.

[8] Svenska Kraftnät (2019), ”*Prislista 2020 för Stamnätet*”

3.1.2.3 Great Britain

In Great Britain, the basis for the capacity charge is the customer's average metered output during the three half hour settlement periods of highest net system demand between November and February each year. Although peaks can occur at any time, each peak in the calculation must be separated by at least ten full days[9].

3.1.2.4 Summary

The tariff arrangements discussed above have major differences. It can however be said that the system in Great Britain and the Norwegian system send price signals that are in line with long-term grid costs, as consuming when the system load is high leads to higher tariffs*.* The Swedish system and the Icelandic system are aimed at individual consumption, with potentially only weak connection to system loads. The link to long-term marginal grid costs may thus be significantly weaker.

At this stage, it is worth mentioning that the arrangements in Sweden are under review, and that the Swedish TSO was advised to introduce a clearer link between the basis for the capacity charge and the long-term marginal grid costs[10]. If Sweden moves away from its current tariff arrangements and closer to what the UK or Norway has, if would leave Iceland alone among those four countries with a basis for the capacity charge linked to the customer's peak[11].

Before recommending a transition to another basis for the capacity charge, we investigate what capacity basis a selection of Icelandic customers are getting in Iceland, and would get in Norway and Sweden if they were to establish there. In addition, we comment on the correlation between customer's peak and system peak, as well as what type of customers may connect to the electricity network in Iceland.

3.1.3 Possible options for Iceland

3.1.3.1 Base for capacity charge for existing customers based on alternative tariff arrangements

The figure below illustrates the difference in basis for capacity charge when comparing the methodology used in Iceland with the ones in place in Norway and Sweden. The analysis is based on data for 2019, with the exception of Norway which by design must take into account several years[12]. A range of

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[9] NationalgridESO (2019), "Final TNUoS Tariffs for 2019/20, National Grid Electricity System Operator"

[10] Thema (2019), " Review of the Swedish transmission grid tariff model"

[11] Readers interested in a wider comparison can look in into the ACER (2019) report, chapter 8.2.

[12] As mentioned earlier, the Norwegian system is based on data from the previous five years. AFRY obtained data on Iceland for the last three years, and based the analysis on those.

consumers was analysed and for each consumer type we present the highest, lowest and weighted average deviation.

Figure 3 Base for capacity charge, Iceland compared to Norway and Sweden

	Difference Iceland-Norway			**Difference Iceland-Sweden**		
	Lowest	Weighted average	Highest	Lowest	Weighted average	Highest
PIU: Aluminium/ silicon producer	-6%	-3%	-1%	0%	0%	7%
PIU: Data centre	-26%	-20%	12%	2%	3%	4%
DSOs	-6%	5%	57%	1%	12%	75%

Source: AFRY analysis on data from Landsnet

Assuming a single revenue cap, the Norwegian system would benefit aluminium and silicon producers (-1 to -6%), whereas the impact is less clear for data centres. Those that have high consumption during the peak would face a higher basis for the capacity charge, whereas others could experience a significant decrease. For DSOs, most would see an increase in their basis, up to 57%, with the exception of one DSO which would experience a decrease.

In the Swedish model, we see that PIUs would not largely be affected by a change in the basis for calculation, whereas most DSOs would experience a significant increase. Data centres would experience an increase of about 2-4% in the MW base.

This exercise shows that large power intensive units are not very sensitive to how the basis for the capacity charge is calculated, whereas DSOs and data centres are more sensitive.

3.1.3.2 Base for capacity charge for possible new customers

Recent customers that have connected to the transmission network are in the scale of 10-100 MW. While new large PIUs are unlikely in the upcoming years, prospective customers are likely to also be in the 10-100 MW range.

These prospective customers are likely to have more load variation than traditional power intensive units in Iceland. This, in addition to:

- The fact that consumption outside peak contributes to a better utilisation of the electricity network,
- The fact that consumption during peaks generate new investments and costs,

makes it increasingly important to connect the basis for the capacity charge to the overall system load.

3.1.4 Recommendation

We recommend replacing today's methodology (average of the four highest 60-minute monthly power-peaks of the year for each delivery point) by a model similar to the one of Norway. The basis for the capacity charge could thus be the average of the consumption during the maximum load hour in each of the last five years.

For users, it would provide incentives to avoid peak during high load hours, thus reducing the need for future investments, and make it cheaper to increase consumption off-peak and thus contribute to a better utilization of the system.

For Landsnet, this system presents a range of benefits as:

- It would not require new data,
- Administrative costs are low, and
- The system contributes to revenue predictability, especially if a large portion of the allowed revenues is perceived via the capacity charge and on historical values (which would reflect the cost structure in the network).

AFRY has been made aware that Landsnet's analyses show that capacity in the network system will be satisfactory when current investments are finalized. The need for a modified basis for the capacity charge linked to system load may thus be reduced in the upcoming years. This however does not change our recommendation.

3.2 Capacity charge for in-feed

3.2.1 Situation in Iceland and limitations

Producers connected to the transmission network pay a delivery fee. In chapter 5, we propose to charge producers so that they will pay a larger share of the allowed revenues of the Icelandic TSO than they currently contribute. The key question that we discuss in this chapter is how producers should be charged.

The current tariff structure consists only of a fixed delivery charge in ISK per year. The fixed nature of the fee may not fully reflect the cost imposed to the network by different users, as it does not vary depending on factors under the control of users. An alternative tariff structure could be designed, which incorporates elements to send appropriate signals to network users.

3.2.2 Learnings from the literature

Tariff design has been the subject of abundant literature, but the lessons to be learned are often dependent on the specific situation of the country under analysis. One example of valid points on tariff design that could be applied in multiple contexts is the Agency for the Cooperation of Energy Regulators (ACER) recommendation[13] on production (injection) charges:

- energy-based charges shall not be used to recover infrastructure costs, as they would be reflected in bidding behaviour or bilateral contracts and therefore passed on to consumers
- the use of energy-based charges for recovering the costs of losses and ancillary services could provide efficient signals, and
- capacity-based charges or fixed charges can be appropriate to recover infrastructure costs, as long as they reflect the costs of providing transmission infrastructure services to producers.

3.2.3 Practice in other European countries

The ACER[14] surveyed a total of 29 European jurisdictions in 2019. The survey shows large differences in the approach to injection fees across countries. For example, in 14 of the 29 jurisdictions, producers pay a form of injection fee based on a combination of delivery charge, energy charge and capacity charge:

- 11 countries at least partially based their charge on the volume of energy,
- 7 countries charge based on energy-only, while 3 countries also have a capacity-based component and 1 has an additional lump-sum[15] component, and
- 3 countries have a capacity based component only.

For the purpose of this report, we chose to focus in more detail on the following three countries: Great Britain, Norway and Sweden. In these countries, production charging is an established practice and there are ongoing discussions around the charging structure.

3.2.3.1 Great Britain

In Great Britain (GB), there are two charges for transmission costs: the transmission network use of system (TNUoS), which covers the infrastructure cost and is a capacity charge, and the balancing services use of system (BSUoS), which reflects the system operation costs and is an energy charge.

The infrastructure charge on production is calculated to cover the long-run incremental costs of transmission investments. The cost scalar in the GB model

[13] ACER (2014). Opinion of the agency for the cooperation of energy regulators no 09/2014

[14] ACER (2019), "*Practice report on transmission tariff methodologies in Europe*"

[15] A lump-sum component does not depend on factors directly under the control of the user. Examples of factors under the direct control of the users are the plant capacity or the energy produced.

is based on the indexed historical asset cost for generic technology types, along with an overhead factor to represent asset maintenance and a security factor.

Another feature of the GB system is the distinction between three types of generation in the 'wider tariff', which is the charge to which all producers are exposed. The wider tariff is composed of:

- The 'year round shared' element, which is at the same level for all producers and reflects the costs of transmission network needed to save balancing costs. This is shared by both flexible and inflexible producers and is influenced by the utilisation time, so that those producing more pay a higher share of such shared component.
- Other components of the 'wider tariff', which are calculated differently depending on the type of generation:
    - 'The Year Round Not Shared' elements, which reflects the cost of transmission circuits needed to save balancing costs, particularly triggered by inflexible generation, are paid fully by non-flexible producers (such as wind, nuclear or run-of-the-river hydro), while the flexible producers pay this component in proportion to their utilisation time.
    - The 'Peak' element, that looks at network investment to secure peak demand is not paid by intermittent producers.

In the GB model, the tariff for a producer is thus the result of multiple elements which reflect costs to the transmission network imposed by producers connecting at different locations and utilising the network. In addition comes a 'residual' charge, which aims to fully recover the allowed revenues of the TSO. The tariff is calculated annually[16], and each element is stable across the year; a five-year forecast is published by National Grid on an annual basis.

3.2.3.2 Norway

In Norway, producers face a variable energy charge that reflects transmission losses (negative charges where production reduces losses and positive where production increases losses), as well as a lump-sum charge. The latter is based on the average in-feed of the individual power-plant over the last 10 years, multiplied by a fee in NOK/MWh which is the same for all power-plants (production fee plus fee for system services).

[16] National Grid typically calculates the tariff annually, but the Connection and Use of System Code (CUSC), which sets the contractual framework for charges and connections in GB, allows for changes throughout the year with 150 days' notice to the regulator.

3.2.3.3 Sweden

In Sweden, producers face both a capacity and an energy charge. The capacity charge (per MW) is higher in the North than it is in the South to provide locational incentives (more production in the South) and minimize investment needs in the transmission network. The energy charge reflects losses and can be negative or positive.

3.2.3.4 Relevance of European practice

The tariff arrangements from GB, Norway and Sweden have major differences, but also share an element of interest: the revenue per MWh from producers is capped (EU-regulation), which limits freedom when putting in place a tariff on producers[17]. As these jurisdictions are becoming more and more interlinked with neighbouring countries, tariffs in neighbouring countries also play a role in defining domestic tariffs. A better harmonisation of tariffs will avoid sending signals which lead to suboptimal investment decisions at a regional scale.

There are thus clear limitations in looking at European countries to inform the ongoing process in Iceland. That being said, the experience from these countries is useful, as is the extensive literature published on the topic.

3.2.4 What are possible options for Iceland?

There are three questions to consider when assessing options for Iceland:

- What services provided by Landsnet should the tariff aim to recover?
- What structure should the tariff have?
- What economic signals should the tariff send?

3.2.4.1 What services provided by Landsnet should the tariff aim at recovering?

We propose three options regarding what services the fee could cover:

1. Keep the current approach (no distinction between investments, maintenance and system operation costs)
2. Separate system operation costs from the infrastructure costs, where all the infrastructure-related costs are considered as a single block
3. Separate system operation costs, operational costs (OPEX) and fixed-costs (CAPEX)

Based on current practice from the countries we surveyed, we recommend separating the system operation costs, (options 2 and 3), and in particular

[17] In 2018, Statnett tried to get the cap increased, without success. The aim of the increase was to reflect that a significant share of the network expansion is related to export of energy, which is not mirrored in today's tariffs.

charge the costs related to system operations separately from the **infrastructure charge** (option 3).

This is particularly relevant if a locational marginal pricing (LMP) is introduced in Iceland[18]. In this case, some of the costs of congestion will be captured by congestion revenue to the TSO if price zones are introduced, and another element to reflect the losses could be incorporated at a later stage. We also favour option 3, as the network expansion costs are more directly attributable to an increase in required firm capacity from users of the network.

3.2.4.2 What structure should the tariff have?

We propose to focus here on the recovery of the infrastructure costs through an infrastructure charge as discussed in the paragraph above, and leave the discussion around the recovery of system operation costs, alongside other system services, for the next round of review of priority areas.

We concluded that a capacity charge is the most appropriate option for the infrastructure charge. To come to this conclusion, we assessed four options:

1. Keep the current approach - Fixed delivery charge
2. Base the charge on the in-feed - Energy charge
3. Base the charge on the historical generation - Lump-sum charge, similar to the 'Norwegian' approach
4. Base the charge on the power component - Capacity charge

Under Option 1, the entire infrastructure cost is spread equally over the total number of generating plants. Regardless of the plant size or annual generation, each incurs a fixed cost. The main challenge with this is that it would encourage large connections, especially if in the future the share of revenues from generation was to increase from today's level.

Option 2 is to have a generation based tariff. Here the revenue cap portion to be recovered for infrastructure cost from producers is spread over the total expected generation for that year (Option 2A). The main challenge with this option is that it would favour low utilisation time technologies, thus not reflecting the costs they impose on the transmission network. As an illustration, the impact of setting a tariff of 1 monetary unit (MU) per MWh using typical utilisation time, would be the following on a MW basis:

[18] There is an ongoing Landsnet project to implement a LMP system in Iceland.

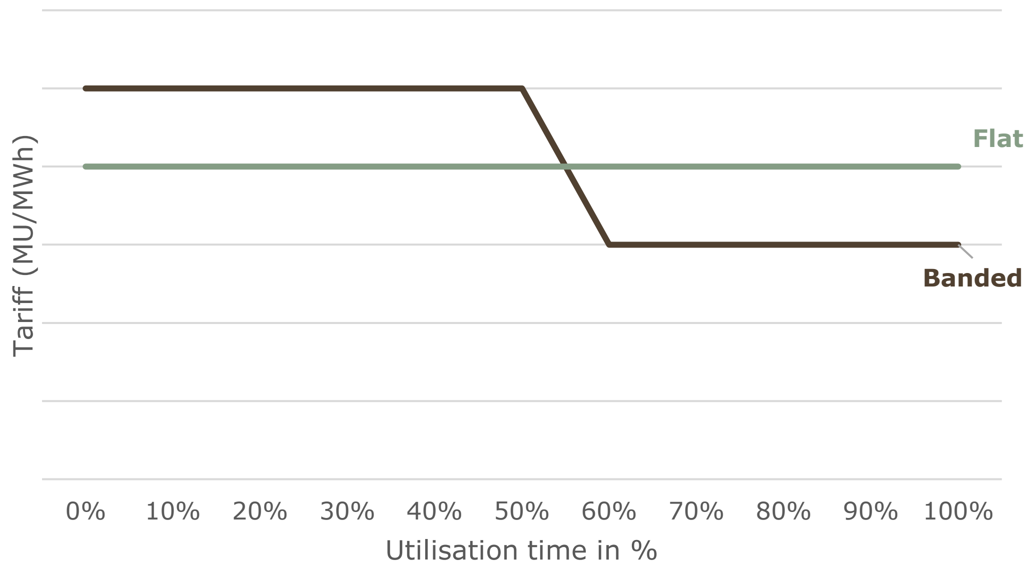
– Hydro-power: $1\frac{MU}{MWh} * 6666\,h = MU\ 6666\ per\ MW$

– Geothermal: $1\frac{MU}{MWh} * 7500\,h = MU\ 7500\ per\ MW$

– Wind: $1\frac{MU}{MWh} * 2300\,h = MU\ 2300\ per\ MW$

The examples show that an energy charge would mean that power plants with low utilisation time would pay less for the network capacity they require than power plants with high utilisation time. This is not cost-reflective. A possible variation could be to introduce a banded tariff (Option 2B) and apply a higher energy charge for those with a low utilisation time and a lower energy charge for those with a higher utilisation time (more than two bands could be envisaged). This is illustrated in Figure 4.

Figure 4 Illustration of a flat and banded energy tariff (monetary unit/MWh)



The main drawback of the introduction of an energy charge, in particular if banded, is that the charge will be reflected directly in the short-run marginal cost of plants, potentially affecting the merit order curve in the wholesale electricity market when it is in place in Iceland[19]. Option 2 is however a possible option.

Option 3 is to have a generation based tariff similar to the one used in Norway, which is to charge a lump-sum based on historical production. In Norway, the

[19] In a wholesale market, the producer will include the energy charge in its energy bids to the power exchange or in its bilateral contracts, possibly causing a distortion in the original market behaviour of these agents and the outcome of the wholesale market. As an example, producers with higher margins, which sell electricity at a price well above their short-run marginal cost, would be able to absorb part of the energy charge through a decrease in their margins; producers operating at low margins would have to pass more of the charge through to consumers instead, and therefore would see their market share reduced. This issue is of particular relevance for producers, as they typically determine the market price with their bids in most power systems.

option seeks to solve the main challenge discussed in the previous paragraph, namely that the charge will be reflected directly in the short-run marginal cost of plants. As the annual fee is based on historical generation during a fixed number of previous periods, a reduction in the charge would only happen if the production is reduced over a period of time spanning over several years. As discussed for option two, technologies with a low utilisation time would be advantaged, but the introduction of a banded tariff would partly mitigate this concern. Option 3 is considered a possible alternative.

Option 4 is to have a capacity based tariff. Here the total revenue cap, to be recovered for infrastructure costs of producers, is spread over the total installed capacity. This seems to be the most promising, since it is cost-reflective given that investments in the network are strongly linked to the peak capacity. We investigate three possible MW-bases:

- Maximum production (Option 4A)
- Subscribed capacity (Option 4B)
- Production during peak hours (to mirror the suggestion for the basis for capacity charge on consumption given in Section 4) (Option 4C)

Maximum production (Option 4A) is the most appropriate base under the assumption that "*individual peak hours are synchronous with grid peak hours*"[20], which may not be the case for all power plants.

A variant (Option 4B) would be to define capacity in relation to the 'firmness' of access of the contracted capacity (subscription model). With this variation, technologies that are willing to reduce their output at times when this would generate additional costs to the network could contract a lower firm capacity and accept to be constrained down in certain periods. Based on our engagement with wind producers, it appears that wind developers are willing to reduce their generation when the system requires, therefore one can assume that they would be willing to purchase a lower capacity of firm access than their technical maximum. In the definition of the detailed design, Landsnet will need to define if there would be standard contractual terms available or if the access level would be defined ad-hoc to the power plant.

Production during system peak (Option 4C) may create unwanted consequences such as reduced production during peak hours in order to minimize tariff charges. In turn, reduced production can increase system operation costs. Also, a number of producers may get an unrealistically low tariff if they do not have production during system peak (this could be the case

[20] Agency for the Cooperation of Energy Regulators (2019), "*Practice report on transmission tariff methodologies in Europe*"

for example for technologies with low utilization times). Therefore we decide not to consider this option further.

3.2.5 Recommendation

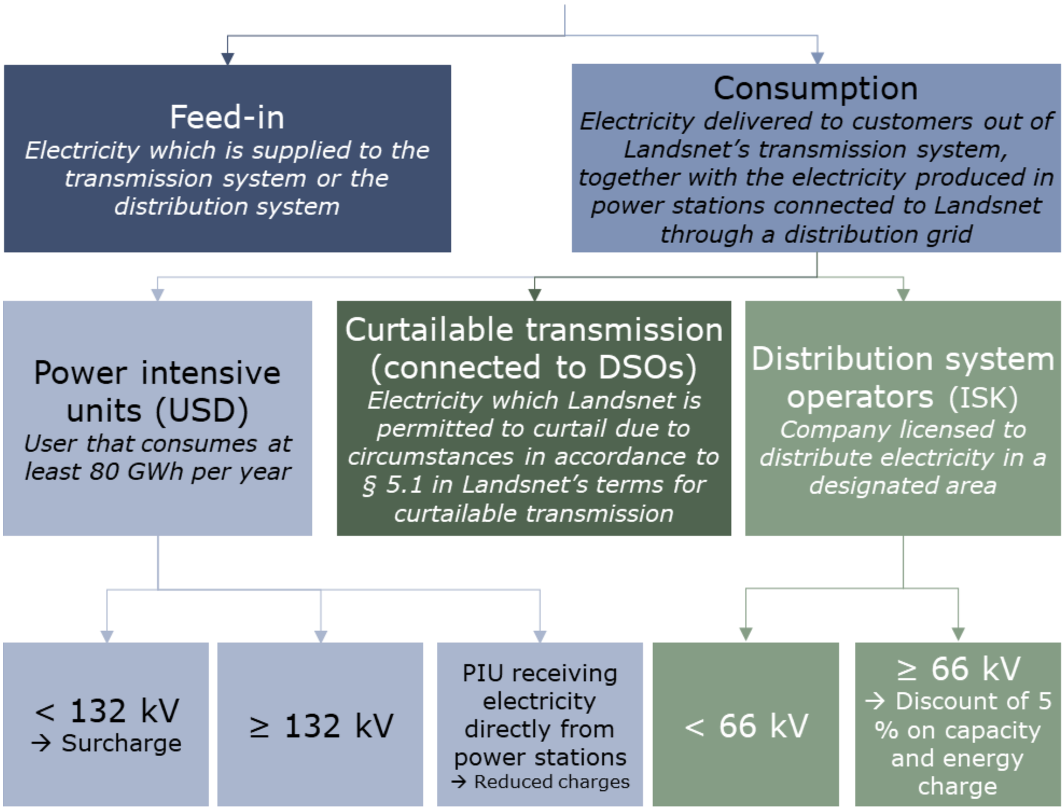
In summary, our preferred option is a capacity based tariff (option 4). In particular, a subscribed capacity model would be the preferred application for a capacity charge (option 4B), as it would allow not only to reflect the cost imposed by each generator on the network directly in the tariff producers pay, but it would also allow producers themselves to reduce to the level they deem appropriate the capacity they subscribe to.

4 Customer categories

4.1 Situation in Iceland

Current customer groups connected to the transmission network are illustrated in the figure below. The illustration is in line with the publication nr. 34 from Landsnet[21].

Figure 5: Current customer groups in Iceland



The main split is between generation (feed-in) and consumption (feed-out). Consumption is further divided between power intensive units (PIU) which pay a tariff in USD and distribution system operators (DSO), which pay a tariff in ISK.

To qualify as a PIU, a user needs a consumption of minimum 80 GWh annually within three years after starting its operations. PIUs are typically connected to the transmission network at 132 kV or above. A separate tariff applies for PIUs connected to a lower voltage level. Power intensive units connected directly to a power plant, it can qualify for reduced charges.

[21] Landsnet (2019/34), "*Tariff for the Transmission of Electricity and Ancillary Services*", valid from January 1st, 2020

DSOs are typically connected to the transmission network at 66 kV or below. If a DSO is connected to a higher voltage level, it will qualify for a discount on the applicable capacity and energy charge.

Curtailable transmission connected at the DSO level is exempted from the capacity charge under certain assumptions.

A number of challenges were identified in an earlier phase of the project (see Section 2.4). As a result AFRY investigated the current customer groups.

Assigning customers to different groups will ideally be based on verifiable and network-related criteria. It is thus natural to split between production (in-feed) and consumption (out-feed). Landsnet also has two separate revenue-caps (in ISK and USD) which create further two costumer groups: PIUs and DSOs.

The focus in this section is thus on whether the DSOs should be separated in several groups, and whether PIUs should be separated further.

4.2 Current customer groups in other countries

Norway separates between *in-feed* and *out-feed*. Consumption is further separated between *curtailable transmission* (four different groups depending on warning time and how long a customer can be curtailed[22]) and *other consumption*. In case a consumer has a capacity exceeding 15 MW and a consumption of at least 5000 full load hours, it qualifies as a *power intensive unit*. PIUs get a reduced fee compared to other users (50% rebate in 2021).

In the UK, users are separated between *in-feed* and *out-feed*. Production is further split between *conventional carbon, conventional low carbon* and *intermittent production*. Load factor is also used in setting the tariff for each producer. Consumption is separated into 14 tariff zones, *half-hourly* (commercial metered demand over specific time periods), *non half-hourly* (domestic, or smaller non-domestic premises) and *embedded export* (a credit for embedded generation over specific time periods)[23].

Norway and the UK were chosen as illustrative examples as they are very different. A system based on characteristics (network-level, load factor, co-location, flexibility, capacity, energy, etc.) is likely to be more robust as new customers will always fall under existing categories. A system based on clearly defined groups will likely need to be updated more often, and thus create uncertainty for users.

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[22] Note that Statnett plans on phasing out tariffs for curtailable transmission as curtailment is rarely used.

[23] National Grid (2019) "*Final TNUoS Tariffs for 2019/2020*"

Landsnet has two revenue-caps, which prevent a system purely based on characteristics. It is however possible to combine characteristics when possible and a limited number of clearly defined groups.

4.3 Relevant criteria to differentiate customer groups

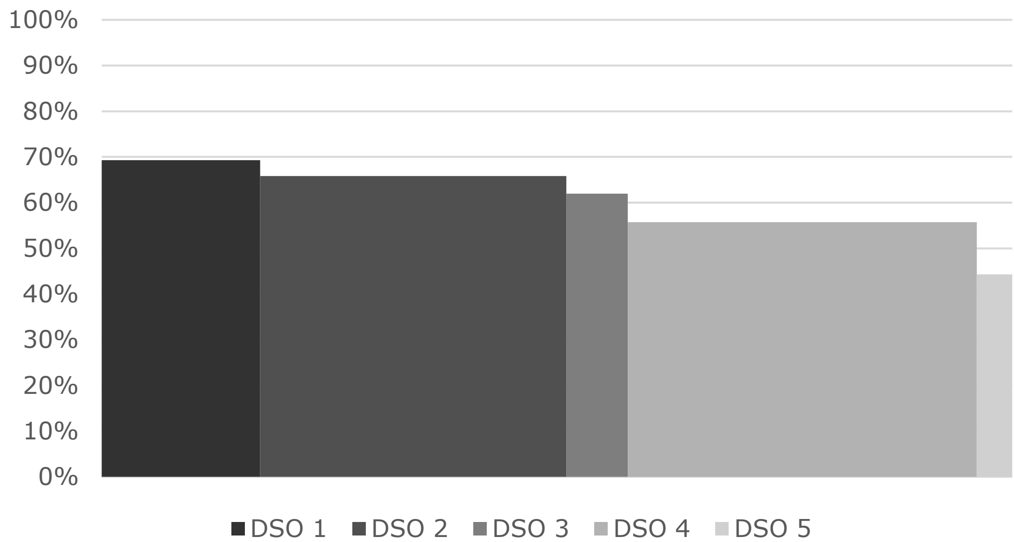
Different customer groups are necessary to reflect differences in how various customers impact the electricity network.

4.3.1 Focus on DSOs

AFRY performed a number of quantitative analyses to identify potential differences between DSOs. Each DSO shows daily, weekly and seasonal consumption patterns.

There are differences in capacity factors between DSOs[24], which range from about 45% to 70% (see Figure 6). In addition, the consumption pattern is highly correlated (0,67-0,77) with system load, meaning that high load from DSOs correlate well with the system load.

Figure 6: Capacity factor for five DSOs in Iceland



The differences between DSOs do not justify creating separate groups. That being said, DSOs are connected to different voltage levels in Iceland, and Landsnet delivers at 11 – 132 kV. Customers located at lower voltage level require more network (for example access to the 220 kV network, transformation to 66 kV and extraction at that level), which justifies a surcharge

[24] The load factor is based on 2019-data and obtained by dividing total energy by maximum hourly load that year.

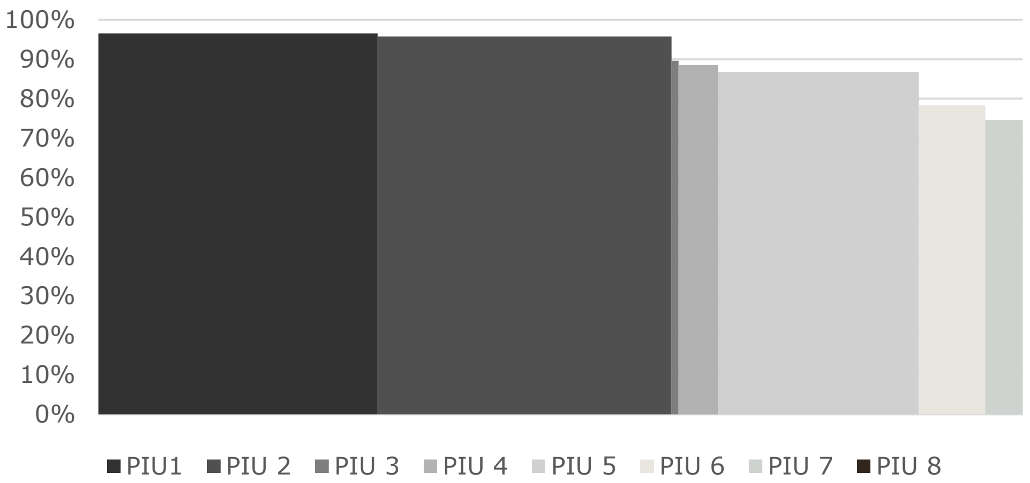
in tariff. This is in line with grid code B9 in Iceland, and does not represent a difference from today's arrangements.

Curtailable consumption is an area we willingly do not address until we review the last priority area (procurement of system services). It is expected that curtailable consumption reduces the need for network capacity, although it is not clear whether it is best achieved via a separate customer group at this stage.

4.3.2 Focus on PIUs

Larger differences were identified between power intensive units. The following figure shows the size and capacity factors of eight PIUs in Iceland. Two data centres were excluded as they started consumption during 2019, as well as a large PIU due to technical problems. The figure nonetheless shows that some of the PIUs are very large (over 300 MW), others are mid-sized (70 – 150 MW) and others are smaller (< 30 MW). Large PIUs and some smaller PIUs have very high capacity factors, whereas smaller PIUs typically have lower load factors.

Figure 7: Capacity factor for eight PIUs in Iceland



The capacity factor is important when identifying cost-reflectiveness. A tariff with a low capacity charge will imply that customers with high capacity factors pay more for each kW they impose on the system than customers with low capacity factors. The capacity factor is thus an obvious characteristic one can consider when defining customer groups. The capacity factor needs to be considered together with how the costs are split between the capacity and energy charges.

The PIUs correlate poorly with system load, the largest PIUs having a correlation of 0.1 – 0.2 (stable consumption throughout the year). This correlation varies between users and can be negative (-0.1, implying that this PIU had lower consumption when system load was high) or quite high (up to

0.7, meaning that a PIU has a consumption pattern in line with system load). A PIU with high correlation will thus lead directly to a higher need for network, whereas a PIU with do so at a lower extent. The consumer's typical load profile may thus also a relevant characteristic. This element can however be accounted for in how the basis for the capacity charge is set. Since we suggest to align the basis for the capacity charge with system peaks, we do not include correlation as a relevant characteristics when we make suggestions on how customer groups could be defined.

On top of these differences, PIUs are connected to the network at 33 kV, 132 kV or 220 kV. This means that some of the PIUs need the power to be delivered at a lower voltage than others, using more network and thus creating additional costs. Different voltage levels is also a characteristic which could be used when defining customer categories.

Differences in capacity factor, size, consumption pattern and voltage levels are thus relevant characteristics for placing PIUs in different customer groups.

In addition, Landsnet disclosed that current connection requests are below 100 MW, and often from customers with short lead times, more expected variation in consumption as well as shorter commitment times. The sum of these elements justify separating PIUs in subgroups, as opposed to one main group for PIUs as today.

Before looking into splitting PIUs in subgroups, AFRY investigated how PIUs are split in other countries[25]:

- France: PIU if minimum 10 GWh and load factor for 7000 hours (which corresponds to a load factor of 80% if expressed in percentage)
- Germany: PIU if minimum 10 GWh and 7000 hours
- Norway: PIU if minimum 15 MW and 5000 hours
- Slovakia: Several groups – yearly consumption of 200/250/350 MW and 1/2/2,5 TWh in consumption

The variation between country gives no clear indication on what may be appropriate for Iceland, although they provide evidence that this is a country-specific consideration.

4.3.2.1 About the 80 GWh limit and security of supply

In the earlier phase of the project, several stakeholders expressed a wish to see the lower limit to qualify as a power intensive units reduced from today's level of 80 GWh. This was also a key aspects of the feedback from stakeholders on an earlier suggestion on how the PIU categories could be changed.

[25] Entso-E (2017) "*Entso-E Overview of Transmission Tariffs in Europe: Synthesis 2016*"

Not all countries differentiate between power intensive users and other types of users. Among those countries that do, the reason is often linked to the location of PIU being close to production (reduced need for transmission network) and the impact on system services (reduced). Examples are:

- France and Germany, with a lower limit set to 10 GWh and 7000 hours (corresponds to a minimum of 1,42 MW)
- Norway, with a lower limit set at 15 MW and 5000 hours (corresponds to a minimum of 75 GWh)

Those countries have a lower limit than Iceland. That being said, there are other differences from the system in Iceland. For example, a power-intensive unit with over 15 MW and 5000 hours in Norway will only qualify as a customer at the transmission level if is directly connected to that level. PIUs connected at the distribution level still qualify for a lower transmission network tariff, but pay an additional tariff to cover the costs of the DSO.

Landsnet is in the process of collecting data from DSOs to identify how a change in the lower limit would affect customers. The process is ongoing and we do not suggest changes at this stage.

In addition, Landsnet is also looking into security of supply, as there are different needs and requirements between network users.

4.4 Suggestion for changes

4.4.1 Suggested categories

The changes are related to PIUs. We chose to retain the following characteristics to justify the change:

- Size and capacity factor
- Stability in consumption
- Voltage level
- Ownership of substation

Correlation between system load and consumption was also deemed a relevant characteristic. However, the suggested change in how the capacity charge in MW is set takes this aspect into account.

Concretely, we suggest the following groups:

(i) Customers with a minimum of 80 GWh (under review)
(ii) Above 30 MW and minimum 6000 hours of consumption

The lower limit is equivalent to today's limit thus far. Customers between 10 MW (8000 hours) and 30 MW (down to 2667 hours) would fall under this category. Most data centres would fall under this category. It is expected that most new customers would fall into this category in the near future, based on information from Landsnet. We would thus find customers with lower capacity factors in this group.

In the second group, we would find larger power intensive units and large data centres, which typically have higher capacity factors.

Some PIU own their substation. It is unfair if they pay the full cost of this substation, and also pay a share of the substation for all other customers. We suggest a new rebate for users who own their substation. We also find it natural to continue with the surcharge for *stepping down the electricity from one level to the delivery voltage requested* (in accordance with grid code B9). The recently introduced shallow connection fee does not impact this model.

5 Share of the revenue cap to be recovered from producers and tariffs

5.1 Current situation in Iceland

Landsnet currently recovers around 1% of the revenue cap from generators. The fee is levied as a yearly fixed delivery charge, flat for all generation plants. The fee does not make any distinctions between system operation and infrastructure costs. There is a separate charge for ancillary services and transmission losses.

There is no exposure to transmission price signals for generators and the payment of a fixed delivery charge encourages larger connection requests.

During the earlier phase of the project, we surveyed the opportunities and challenges from different generation technologies in responding to potential price signals. These are reported in Table 1.

Table 1 – Generation opportunities and challenges in responding to price signals

Generation category	Opportunities for response	Challenges for response
Hydro	Some flexibility in siting decision, subject to resource availability Landsvirkjun already provides some flexibility within existing hydro portfolio (between 1 week and 2 hours ahead)	Hydro plants all owned by Landsvirkjun which prevents effective competition between different hydro generators to provide response
Geothermal	Stable levels of production	Low locational flexibility as have to site within areas of hotspots Can only be on or off, rather than varying production levels Little geographical diversity in existing portfolios of each operator. This makes it hard for existing operators to provide geographical flexibility in operation
Wind	Some flexibility in siting decision, subject to resource availability Flexibility to reduce output	Cannot raise output above potential from wind speed at time Needs storage to flex production over time

Moreover, Landsnet has recently introduced a shallow connection charge, which will reflect the cost of the non-shared cable to connect a new generator to the nearest substation. Finally, Landsnet is minded to introduce a spot electricity market in Iceland, based on Locational Marginal Pricing, which will have effects on the revenues generators will collect.

5.2 How much of the revenue cap should generation cover?

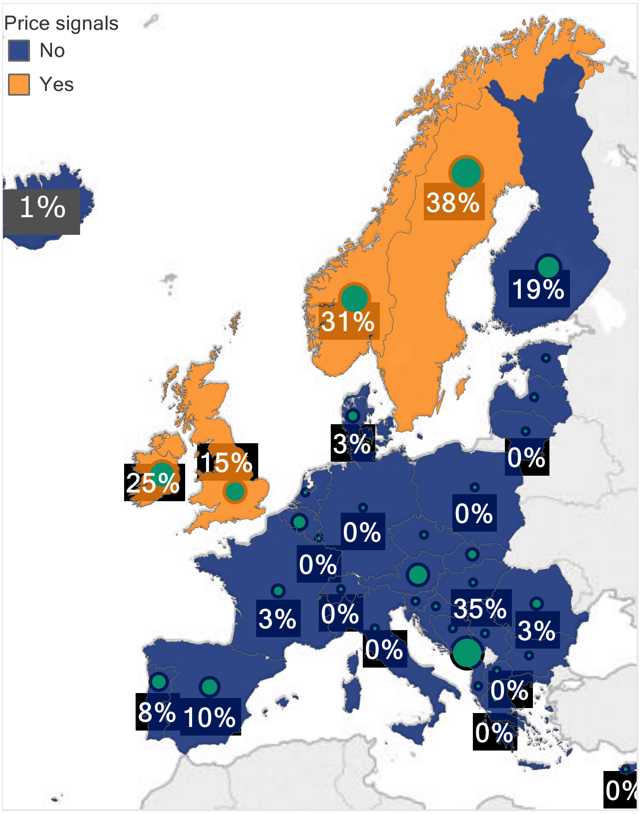
5.2.1 Economic theory

Producers should be charged the share of network costs that they cause to the system (cost reflectivity) and this may vary depending on the circumstances. Specifically, a charge on producers should cover the long-run incremental costs of transmission investment caused by producers.

5.2.2 Share of revenues from generators in Europe

As illustrated in Figure 8, the share of charges levied on generators in Europe varies widely, from 0% in most countries in Central Europe to 38% in Sweden.

Figure 8 - Share of revenues recovered from generators in Europe



Source: ENTSO-E Overview of Transmission Tariffs in Europe: Synthesis 2017

In a recent survey from ACER, countries that charge 0% of charges to generators have asserted that the main reasons for the absence of charges on generators is the legal barrier or a desire to be competitive with other countries that do the same[26].

[26] ACER (2019). ACER Practice report on transmission tariff methodologies in Europe

5.2.3 Share of revenues from generators in Iceland

Landsnet is currently reviewing the costs caused by generators of the total TSO costs, by looking into the various components of the network and allocating it between generators and other users. This process is ongoing and will serve as the base for estimating the share of the revenue-cap which will be allocated to generators.