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Explanatory memorandum

Appendix 3

Dnro 3171/040300/2023

Explanatory memorandum confirmation decisions regulation methods in the sixth regulatory period from 1 January 2024 to 31 December 2027 and for the seventh regulatory period from 1 January 2028 to 31 December 2031

- electricity distribution network operations *and high-voltage distribution network operations*

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1 Adjusted assets and capital invested in network operations

1.1 Principles of determining the assets invested in network operations and rate of return

The Energy Authority notes that the adjustment and straight-line depreciations of network assets and the determination of the rate of return are interconnected. In other words, the method for determining the rate of return sets the criteria for how the adjustment of assets invested in network operations should be made so that inflation is correctly reflected in the methods in the calculation of reasonable return and straight-line depreciation. Below is a discussion of the matter and the reasons why a decision was made to use the nominal rate of return and the adjustment principle this requires.

1.1.1 Background

In previous methods, the Energy Authority has applied a network revaluation method in which the replacement value of the whole network mass is adjusted using the latest unit price list. During the previous regulatory period, a nominal rate of return including inflation was also applied. In relation to the previous methodologies, it was found that unit prices would not be index-adjusted over the periods, as inflation has been taken into account in the rate of return. However, since the publication of the first guidelines in spring 2023, the Energy Authority has observed in its official work that the principle of the previous methodology, which excludes unit prices during the regulatory period only, fails to correctly or sufficiently eliminate the effect of inflation. The Authority found out that the principle of adjustment of the entire network assets would probably need to be changed if the nominal rate of return was used as the rate of return.

In connection with the first public hearing of the guidelines (3/2023) and based on the statements received after the end of the consultation period, the Energy Authority decided to order a report from DFC Economics S.r.l.[1] on the theoretically correct procedure for adjustment for inflation for determining the rate of return, the basis of return and the straight-line depreciation of the regulation methods. The assessments and recommendations of the report serve as a key source for assessing methodological changes related to the rate of return and the valuation of the network.

As abandoning the use of unit prices is not justified due to the objectives set by legislation for efficient investments, it is essential that the rate of return and the network assets adjusted for unit prices are determined so that the methods are as

[1] DFC Economics S.r.l., Rate-base adjustment for inflation in energy networks regulation: A report for Energiavirasto, 2 October 2023

thoroughly justified as possible from the point of view of reasonable pricing and cost equivalence as well as theory and that inflation would not be taken into account twice. At the same time, however, it should be ensured that the changes or the timing of the changes are fair to the different network operators, as the different models produce a reasonable cash flow for the maintenance period of the components in different forms, depending on the age structure of the distribution system operators.

1.1.2 Grounds for the adjustment of network assets based on DFC's report

DFC's report confirms that the valuation of network assets and the determination of the rate of return are interlinked. According to the study, with the nominal rate of return, network valuation must be based on historical costs, whereas with the real rate of return, the valuation must be based on the current value of the whole network mass, regardless of the year of the investment, i.e. the network must be "revalued" at a higher level based on the inflation rate[2].

DFC's report ensures that the nominal rate-of-return approach based on actual historical costs does not, in practice, include sector-specific inflation, as the valuation of the network is bound to the value valid in the year of investment for each investment. On the other hand, the report also shows that if the real rate of return is used with a general inflation projection together with the revaluation of the whole mass at unit prices, a contradiction emerges in that the network valuation will take into account the development of inflation outturn in the sector instead of the general inflation projections. With reference to the above, the Energy Authority considers that, on the basis of the report, the use of the nominal rate of return together with the unit prices simulating historical costs is more justified. In this case, post-investment inflation is not taken into consideration at all on the network valuation side, while on the rate of return side, inflation is taken into consideration generally, and no assumptions regarding the projected inflation need to be made in determining the rate of return.

According to the DFC report, the real rate of return, together with the revaluation performed using unit prices, is therefore not equally justified for the purpose of taking inflation into account, since the assumption of inflation in determining the rate of return does not correspond to the inflation contained in the updates of unit prices. Moreover, the determination of the real rate of return includes uncertainty

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[2] DFC's report also identified a theoretical approach in which, in the context of revaluation, the nominal rate of return is applied instead of the real rate of return and the double compensation for inflation is prevented by a separate negative revenue adjustment, but was not able to provide a practical approach to this method due to the challenges of defining inflation at the sectoral level.

related to the correct determination of the expected inflation compared to the application of the nominal rate of return. Referring to the above, the Energy Authority finds that, from the perspective of theory, the nominal rate of return and the adjustment of network assets based on historical costs carried out using unit prices that this requires is a more justified alternative than the real rate of return and revaluation carried out based on unit prices.

The DFC report also notes that the revaluation of the whole network mass using the most recent unit prices involves a risk, both from the point of view of customers and DSOs, as fluctuations in network value and price developments at the sectoral level that differ from the overall price developments may lead to overproduction or underproduction of network assets. In other words, from the perspective of reasonable return, the real rate of return, together with the revaluation of the whole network at unit prices, is not as cost-reflective as the nominal rate of return and the valuation principle of the network assets it requires.

1.1.3 Steering effects of the valuation principle

The Energy Authority notes that the problem of fluctuations in network value has already become concrete once during the past regulatory periods. The Energy Authority notes that if the revaluation of the entire network mass is used as the adjustment principle as required by the real rate of return, fluctuations in unit prices may confuse the steering effects of the investment incentive to promote cost-effective investments.

After the publication of the initial guidelines, the Energy Authority has also received comments from DSOs regarding the effect of the investment incentive that reduces benefits. For example, if, on average, the sector as a whole operates more efficiently during the period and unit prices decrease for the next period, the efficiency achieved may end up becoming a sanction for old network assets that exceeds any benefits achieved through improved efficiency. This is an undesirable situation, as the fear of its realisation could hinder the DSOs' efforts to make their investments more efficient.

With reference to the above, the Energy Authority notes that an adjustment based on the nominal rate of return based on frozen annual unit prices is a more cost-reflective option from the point of view of both customers and DSOs, and its steering effect is also more risk-free and justified in principle, as it also allows the cost-effective DSOs to retain their earlier efficiency gains throughout the component life cycle, and prevents the possibly lower level of new unit prices from reversing any previously achieved cost-effectiveness benefits into sanctions. At the same time as the methodologies include a benefit cutting system in the investment incentive, customers will benefit from efficiency during the regulatory periods regardless of changes in unit prices and this system included in the investment incentive will no longer pose a risk to the DSOs even if the new unit prices are lower than the previous unit prices.

Therefore, frozen unit prices prevent DSOs from increasing the value of the old mass by operating inefficiently. As unit prices are frozen, it is always worthwhile for the DSO to aim to invest as effectively as possible.

1.1.4 Criteria for final changes to the adjustment of network assets

Based on the Energy Authority's assessment, the principle in accordance with the draft version published in October 2023, in which the entire old network mass was deflated to the average procurement value using the cost-of-living index is not sufficiently equal and cost-effective for DSOs which vary in terms of age structures and lifetimes. In addition, the Energy Authority has estimated that the separate principles of the hearing document issued in December 2023 should be further refined to ensure better equality and cost-effectiveness for DSOs with different network structures.

The Energy Authority has estimated that the valuation of the old net mass invested before 2024 must be carried out with a new component breakdown and unit prices in accordance with Appendix 1 to the regulation methods. This is used to ensure cost-reflective and equitable network valuation, especially for electricity networks. The unit prices given in Appendix 1 describe the cost level valid during the previous regulatory period, as they are principally based on the 2021–2022 cost level.

Especially in the context of electricity distribution networks, the previous unit price list has been found to have been too inaccurate. This is indicated by the results of the new unit price list and in the regulation data obtained during the previous two regulatory periods. If the old network mass were adjusted with the old component breakdown in 2016, it would groundlessly overvalue the network for some and similarly undervalue the network for others. The Energy Authority has considered that when freezing older network mass, the only fair and non-discriminatory and at the same time cost-reflective solution is to use a newer unit price list in accordance with Appendix 1. The use of the unit price list in Appendix 1 in the adjustment of the old mass will therefore lead to a more cost-effective and equal adjustment of the network assets than the use of the older component breakdown.

As the same valuation principles should be applied to all sectors as a rule and the use of component breakdowns older than those specified in Appendix 1 has not been considered sufficiently justified in electricity distribution, the old network mass of DSOs in all sectors will be adjusted using the breakdown and unit prices specified in Appendix 1. Based on the Energy Authority's view, while inflation is double-counted the basis of this principle slightly more often than in the previous draft methodology, the principle is nonetheless more cost-reflective in the valuation of network structures than in the previous draft methodology as a result of the more detailed component breakdown and also treats different DSOs more fairly and equally as the adjustment of the old network mass is based on the same unit prices based on the cost data from the period 2021–2022 for all sectors and DSOs.

Criteria for abandoning the deflation of the value of the old network mass

Concerning the deflation of the value of the old network mass by the cost-of-living index presented in the draft in October 2023, the Authority has considered that this principle would lead to an excessively discriminatory and sudden change, in which the different network structures would also be taken into account too inaccurately.

There are very different DSOs. The influence of the operating environment may result in significantly longer network lifetimes for some DSOs compared to others. In addition, some of the networks also consist of components with longer lifetimes, which means that the network is older as a rule, even if it still has a long service life ahead of it.

The deflation of the older network mass by the cost-of-living index for several years of investment retrospectively would result in a significant and sudden drop in the cash flow for some DSOs, possibly leading to a considerably lower cash flow than the application of an alternative principle that pays attention to inflation on the side of the adjustment of the real rate of return and network assets justifiable from the perspective of the theory.

In previous methods, the cash flow generated by the value of individual components has been consistent in form, similar to the cash flow in the real model, but only at a higher level due to the application of the nominal rate of return. In this case, the age profile of the network has not been so important. However, for individual components, the profile of the nominal rate of return and the required adjustment principle will change from steady to descending straight as the component ages each year. If the network of a DSO consists mainly of an old network, the time of the change has not been considered to be sufficiently equal with respect to those DSOs with a newer network, if the adjustment of the network assets together with the nominal rate of return had been made on the basis of the principle set out in the draft methodology published in October 2023.

If the cost-of-living index is used to value the network retroactively, especially far back in time, to simulate the historical average cost of purchasing, the risk of overvaluation or undervaluation of the network increases on a component-by-component basis. The Energy Authority has studied the actual cost development per component in recent history and compared this to the development of the consumer price index. Based on these, it can be seen that, at the network component level, there may even be considerable variation from the consumer price index. This means that even if the consumer price index described cost trends to some degree on average, in reality, some parts of the network could have been valued higher, and others lower, than the actual average acquisition cost level. As a result, a measure where unit prices would have to be deflated retroactively for a rather long period based on the cost-of-living index has been considered too uncertain in terms of fairness and cost-reflectiveness, especially as cost data on investments is only available from the beginning of anticipatory regulation and more reliable and comprehensive cost data due to more detailed breakdown and better sampling in unit price surveys is only available from the most recent regulatory periods and, for electricity distribution, only from 2023 onwards, as a result of the introduction of the new unit price list in accordance with Appendix 1.

The adjustment principle in line with this change is also supported by a statement[3] by an academic working group set up by the Ministry of Economic Affairs and Employment and a report commissioned by the Energy Authority (DFC Economics), both of which have in practice proposed that the old network mass could be frozen as a single mass in connection with the methodological change using the old adjustment principle using the same unit prices regardless of the year of investment.

Criteria for specifying the application of unit prices

The Energy Authority has estimated that, due to the annual freezing of unit prices, the aim must be to use average unit prices that are as accurate as possible, but which are nonetheless based on verifiable data realised at the same time.

In draft methodologies depicting the situation in October and December, the unit price applied to the investments in the period would in practice always be based on the actual cost data of the previous period, which would have to be corrected with the consumer price index for as long as five years ahead. Individual components may be subject to major changes in costs within this five-year period, which the use of the consumer price index may not succeed in reflecting sufficiently accurately. This is currently occurring in the case of transformers, for instance, where

[3] VN/2314/2021-TEM-3 ”Academic working group on tariff calculation methods for electricity transmission and distribution, working group statement to the Energy Authority”

there is likely to be considerable increase in costs compared to the development of the consumer price index.

In order to make the frozen network value of investments during the period more cost-effective than their actual value at the time of acquisition before the unit prices are frozen, the Energy Authority has estimated that the latest unit price data based on investments made in the same period will always be applied to the final calculations of the period. The frozen unit prices per year are therefore mainly based on the average actual costs of investments made during the given regulatory period, in which case the final unit prices applicable to investments during the regulatory period will be specified at the end of the regulatory period. At the beginning of the period, before there is information about the exact annual unit prices applicable for the period, the most recent unit price data for the current period will always be applied in the annual estimates for reasonable returns. In other words, the annual calculations are indicative of the valuation of investments in the period before the more accurate unit prices have been determined for the period in question. Therefore, at the end of the regulatory period, new index-adjusted unit prices per investment year based on the actual investment costs of the period are always applied in the valuation of the investments made in the period.

With reference to the above, the unit prices for the sixth regulatory will be determined during the sixth regulatory period and applied to investments in the sixth regulatory period. Similarly, the unit prices for the seventh regulatory will be determined during the seventh regulatory period and applied to investments in the seventh regulatory period. During the period, unit prices are always adjusted for each year of investment using the consumer price index. Meanwhile, for the valuation of the investments actually made before 2024, the unit price list given in Appendix 1 of the methodology document will apply, including unit prices without index adjustment, regardless of the investment year.

The key reason for this change is to reduce the risk of overvaluing or undervaluing investments during the period and to make the adjustment for investments during the period more cost-effective and less risky thanks to the more accurate unit prices, as the unit prices describe the actual costs of the period in more detail. Based on the principle in line with the decision, unit prices do not need to be adjusted using the consumer price index for more than two years, and component-specific changes in costs can thus be better taken into account in the network value as realised for investments in the period before the final freezing of unit prices.

This is not an unproblematic principle from the perspective of the predictability of regulation, as the principle and method are known in advance. The DSO receives sufficiently detailed information on the network valuation in advance, already in the context of annual estimates, even though the valuation will be further specified at the final part of the period regarding investments occurring during the period. The network value data will also be otherwise specified as corrections and more detailed statistics are produced. The more accurate unit prices have a minor effect on the value of the entire network, as this only involves improving the accuracy of previous calculations to better correspond with the costs and only applies to investments made during the period. The Energy Authority also considers it more important to freeze unit prices to the correct cost-reflective level rather than to finalise unit prices a few years earlier, especially if more detailed information on the actual investment costs of the period is available during the period. However, the DSO will have a view of the cost development, which also allows it to have more trust in the fact that investments from the period will be adjusted and eventually frozen based on cost-reflective unit prices. As a result, it will not be in the interest of the DSO to delay those investments whose costs have increased more than the consumer-price index.

Summary

Finally, the Energy Authority notes that the unit price list in Appendix 1 used to freeze the old network mass is mainly based on the cost level valid in the period 2021–2022 in the 2022 value of money, i.e. the most recent cost data from the previous period, and is therefore close to the principle of the separate consultation document presented in December 2023, but with the difference that the applicable unit price list is only more equitable and cost-reflective than before in the valuation of network assets, as it allows taking different types of network structures into account in more detail and applies the same cost level for the valuation of old mass for all. In addition, the Energy Authority notes that the applied principle for the application of unit prices leads to a more cost-reflective valuation of investments during the regulatory period.

1.1.5 Criteria for determining the rate of return

The treatment of inflation in the rate of return depends on the network valuation principle. The nominal rate of return can be applied if the value of the old network assets is not revalued during the lifetime. When applying the real rate of return, the expected inflation rate must be deducted from the nominal rate of return. The DFC’s report concludes that an assumed inflation rate based on a temporally equal horizon of inflation as compared to the maturity of the risk-free interest rate applied in the WACC model, i.e. 10 years ahead, should be applied to turn the nominal rate of return into a real rate of return. In the view of the Energy Authority, the assumed inflation rate should therefore also be updated at the same rate as the risk-free interest rate, i.e. defined annually. As the report points out, there is no directly suitable indicator of inflation rate expectations available. The internal report by the Energy Authority supports this, as the inflation projections published by various parties, such as the Bank of Finland, only extend a few years into the future at most.

In a procedure that involves setting the basis of return on a revaluation basis, the inflation projection at the sectoral level should be applied in converting the rate of return into a real ROR, but the DFC report also notes that it has been more common to apply a general expected inflation rate, which may lead to the overproduction or underproduction of network assets. Indeed, setting the expected inflation rate for network assets correctly is more challenging than defining general inflation expectations[4], and would require more subjective consideration in defining the indicator. Risks with regard to the inflation projection would become concrete especially if negative real returns were allowed in the calculation of the permitted return[5].

As previously noted, the revaluation of the whole mass at unit prices, together with the real rate of return, creates a conflict in that in the years when unit prices are updated, the change reflects the evolution of the inflation outturn on the basis of returns, while inflation expectations should be applied on the basis of the rate of return. In this case, the Energy Authority considers that the most neutral way of taking inflation at the sectoral level into account would be to calculate the average change in unit prices, which would be deducted from the nominal rate of return for the year in question. However, this method would not be theoretically correct, would require making assumptions on the determination of the average unit price and could lead to the above-mentioned situation where the real rate of return would be negative if the inflation outturn at the sectoral level were above the nominal rate of return.

Moreover, taking into account average sectoral inflation is not a cost-reflective and balanced principle between different DSOs, as the development of costs is in fact dependent on the built components. Therefore, depending on the DSO's network structure and the investments this requires, a sector-specific inflation rate would probably not reflect the situation on a neutral basis for each DSO. In practice, cost-reflective and balanced consideration of sector-specific inflation would require more accurate cost monitoring from DSOs in accounting and the development of unit prices should be closely monitored at the component level every year. In turn, this would mean that the unit price list, i.e. the breakdown and specification of network

[4] For example, the basket of the total index of the RKI forecast published in Statistics Finland in its building cost index (RKI) and the Ministry of Finance's economic forecast contains inputs that do not reflect the component costs of network assets.

[5] See legal cases KHO 2015:105 and MAO 503/2012

components, could hardly be developed to meet future needs, and collecting the information needed in practice would require determining unit prices separately each year.

Overall, the DFC's report concludes that theoretically, inflation can be taken into account based on the general inflation rate or sector-specific inflation. However, taking sector-specific inflation into account is problematic in practice and also otherwise a poorer alternative for determining the rate of return in terms of the principles of cost-reflectiveness and equality. Therefore, the only viable option for determining the rate of return is to take inflation into consideration based on the general inflation rate.

The use of unit prices in the regulation methods leads to a situation where updated unit prices always include sector-specific inflation, which also at least partly includes the effect of the general inflation rate. The revaluation at unit prices therefore reflects the realisation of the price development of network assets, not the inflation projections that should be used to determine the real rate of return. This means that if the network is revalued to the current value using the unit prices for the whole mass and the correct principles are applied in this context in compliance with the real rate of return, inflation cannot be taken into account in the real rate of return as theoretically required, because instead of sector-specific inflation, the general inflation projection would have to be used in the real rate of return. The above factors concerning the challenges of determining the real rate of return and the difficulties of coordinating revaluation with the theoretically correct inflation projection are essentially in favour of why the Energy Authority considers it more justified to apply a nominal rate of return, which requires using the network valuation procedure in which historical investments are not revalued during the component lifetime.

1.1.6 Summary of criteria

Based on the Energy Authority's view, the use of the nominal rate of return and the required principle of adjustment of network assets at frozen unit prices dependent on investment years will lead to significantly more justified, risk-free and cost-reflective returns on network assets. The method also has better steering impacts and it is more predictable and robust for fluctuations in the global market. Especially in the current global situation, the Energy Authority considers it important and justified that the method used should be as stable as possible in different market situations and that it should create certainty that no deviation in the market situation will jeopardise the DSO's operating conditions or lead to overproduction regarding the old network mass from a customer perspective. In itself, the determination of the real rate of return already contains more assumptions compared to the nominal rate of return, which may result in an excessively high or low rate of return.

1.2 Depreciation difference from network assets

The provisions on depreciation differ from those laid down in the Accounting Act and the Act on the Taxation of Business Income. As a result, depreciation that differs from planned depreciation in accordance with the Accounting Act can be made in taxation.

Depreciation difference refers to the difference between planned depreciation in accounting and depreciation in taxation. A positive depreciation difference is created during the financial period if the depreciation made in taxation is greater than the depreciation in accordance with the plan. Similarly, a negative depreciation difference is created during the financial period if depreciation made in taxation has been lower than planned. The balance sheet depreciation difference consists of the cumulative positive depreciation difference for the accounting periods. As a whole, a negative depreciation difference is not recorded in the financial statements. (General instructions of the Accounting Board for depreciation according to plan 2007, p. 9)

The depreciation difference is a tax planning tool for a company that can be used to advance or delay taxation. Therefore, an item should not be treated in the same way in the regulation methods as planned depreciations, which are used to amortise the purchase price of an asset over several financial years.

The depreciation difference generated during the financial period is recorded in the Appropriations group Change in cumulative accelerated depreciation in the profit and loss account (chapter 1, section 1 (6) of the Accounting Decree) and in the Accumulated appropriations group Change in cumulative accelerated depreciation in the balance sheet (chapter 1, section 1 (6) of the Accounting Decree). In the balance sheet, the accumulated appropriations are separate from equity, but they contain a share comparable to equity and deferred tax liability. According to the general instructions of the Accounting Board, the distribution of the accumulated appropriations to equity and deferred tax liability can be presented as an appendix to the financial statements, and this contributes to giving an accurate and sufficient view of the financial statements.[6] Unlike in special purpose vehicles, the cumulative difference between depreciation made and accelerated depreciation must be shown

[6] General instructions of the Accounting Board on deferred tax liabilities and receivables. Issued on 12 September 2006

in the consolidated balance sheet divided into equity and deferred tax liability (chapter 6, section 7.5 of the Accounting Act (1336/1997).

The calculation of realised adjusted profit begins with operating profit. In the adjustment of the result, the depreciation according to the profit and loss account plan is replaced by the adjusted straight-line depreciation of network assets determined in accordance with section 6.1.1 of methods. The change in the depreciation difference is given in the unbundled profit and loss account after operating profit, in which case the item is not taken into account when calculating the realised adjusted profit (loss).

In the regulation methods for the fourth and fifth regulatory periods (p. 36), it is noted that 'In the adjusted balance sheet, voluntary provisions and the depreciation of assets other than electricity network assets, deducted by deferred tax liability, are also regarded as equity.' According to the methods (p. 38), 'In the depreciation difference of assets other than electricity network assets, the share of deferred tax liability is regarded as non-interest-bearing debt.' In the calculation of reasonable profit, the depreciation of assets other than electricity network assets is divided into equity and non-interest-bearing debt on the adjusted balance sheet. Deferred tax liability arising from the depreciation difference (20% of the depreciation difference with the current corporate tax rate) is adjusted into non-interest-bearing debt. The remaining 80% is adjusted into equity.

In the regulation methods in the fourth and fifth regulatory periods, the depreciation difference from network assets has been eliminated from the adjusted balance sheet. In practice, the entire item has therefore been included in the equalisation item of adjusted balance sheet and thus in equity.

The depreciation difference from network assets is concerned with tax planning by the DSO used to postpone taxation. In practice, the deferred tax liability is a non-interest-bearing debt that the DSO will have to pay in the future. The regulation methods are based on the WACC model, in which a reasonable return is calculated on equity and interest-bearing debt. The WACC model therefore assumes that no return is calculated for non-interest-bearing debt, which also has a significant effect on the reasonable rate of return calculated using the model. Accepting non-interest-bearing debt items as part of the basis of return therefore results in a reasonable level of return that the WACC model is not intended to generate. The methodology applied during the fourth and fifth regulatory periods to the depreciation difference accumulated from network assets is therefore fundamentally contrary to the WACC model and the regulation methodology as a whole.

In their opinions, DSOs have expressed a view that the regulation methods should be tax-neutral and that the reasonable return calculations should not affect whether or not the DSO utilises the depreciation difference. The regulation on the depreciation difference was also found to have an aim to improve the investment capacity of capital-intensive sectors.

The amount of income taxes recorded by the DSO in the profit and loss account does not affect the calculation of reasonable return. Based on the Energy Authority's opinion, the deferred tax liability of the depreciation difference and its processing do not involve the treatment of the DSO’s taxes by means of reasonable return calculations. The deferred tax liability of the depreciation difference is concerned with the accumulated debt and its nature.

In addition, the Energy Authority considers that any other objectives related to the depreciation difference do not mean that the depreciation difference should be addressed in the methods in contrast to the principles and entity of the regulation of reasonable returns. In line with the above, the regulation methods are based on the WACC model, in which a key element is the division of the liabilities side on the balance sheet based on their nature into equity and interest-bearing and non-interest-bearing debt. The share of the deferred tax liability in the depreciation difference is considered non-interest-bearing debt and the methods should not treat it as interest-bearing debt.

The depreciation difference from network assets should be processed in the same manner as the depreciation difference from other assets. The share of deferred tax liability is left in non-interest-bearing debts, and the share of equity is adjusted to equity by a reasonable return calculation.

1.3 Stocks

According to chapter 4, section 4.1 of the Accounting Act (1336/1997), *Stocks comprise goods intended for sale or other transfer or consumption as such or after processing.* According to chapter 5, section 6.1 of the Accounting Act, *The acquisition cost of stocks remaining at the end of the financial year shall be capitalised as an asset*.

Costs related to stocks are recognised as expenses when an asset is disposed of or consumed. Expense entries on stocks from business operations are made through purchases. Meanwhile, stocks are capitalised on the balance sheet if they have been acquired but not transferred or consumed by the end of the financial period. Through capitalisation, the cost impact of procurements is transferred from the time of acquisition to the time of use or transfer. With reasonable return calculations, purchases and changes in inventories are taken into account in operational costs.

Stocks do not play an essential role in electricity distribution network operations in which the actual goods intended for transfer does not constitute stock inventories. High-voltage distribution system operators did not have stocks in the unbundled financial statements for network operations during the fourth regulatory period. Half of the distribution system operators did not have stocks in the unbundled financial statements for network operations during the fourth regulatory period. In 2016, 2017 and 2019, 38 of the 77 DSOs and in 2018, 2020 and 2021 37 of the 77 DSOs had stocks. For all electricity distribution system operators, stocks accounted for an average of 0.96% of the total sum of the balance sheet for network business operations in the period 2016–2021. For the DSOs with stocks on the balance sheet of network business operations, stocks accounted for 1.96% (1.06% for others than network licence holders of a leased network) of the total sum of the balance sheet for network business operations.

Based on opinions received from DSOs, stock inventories mainly include investment-related assets acquired in larger instalments, and which have not yet been introduced or which it has not yet been possible to allocate to an unfinished investment. For network licence holders of a leased network, stocks also include unfinished projects that, once completed, are sold to the network owner and must therefore be recorded as stocks owing to their nature.

The inclusion of the items in the assets side of an unbundled financial statement in the capital invested in network operations and through this in the basis of returns was discussed in the Supreme Court ruling KHO:2010:86. The ruling was more closely concerned with trade receivables and accrued income items. In its decision, the Supreme Administrative Court considered that trade receivables directly result from the actual business operations and are therefore items invested in network operations by nature.

Meanwhile, the decision found that receivables are imputed items used to convert cash-based items into accrual-based items. Receivables were found to include financial asset-like items and receivables for which no business risk could be assigned in practice. Receivables were therefore not considered to be part of the assets invested in network operations.

Stocks may be intended for own consumption or transfer. In both cases, the capitalisation of stocks involves the amortisation of expenditure, which is used to convert cash-based items into accrual-based items. Components and other assets intended for investments have not been introduced or could not be allocated to an unfinished investment if they have been recorded as stocks at the time of issuing the financial statement. The Energy Authority is of the opinion that there are no grounds for obtaining a reasonable return for such pre-acquired stocks until the assets have been introduced.

As with the fourth and fifth regulatory periods, acquisitions capitalised in the inventories of the network licence holders of leased networks comparable to incomplete investments in the network, which will be sold to the network owner and capitalised on its balance sheet, are taken into account in their balance sheet value in the adjusted balance sheet. This procedure aims at the equal treatment of network licence holders of a leased network compared with DSOs operating in the network. Like other system operators, the components and other goods not in use or which cannot be allocated to incomplete investments are eliminated from the stocks of network licence holders of a leased network.

Non-current assets may include stocked assets if an asset that has been used is decommissioned. No changes in regulation methods are proposed in connection with processing these. The Energy Authority considers that such assets in non-current assets, which are only temporarily removed from actual use and are intended to be reintroduced, can be taken into account in their balance sheet value on the basis of return. In practice, for such network components, the balance sheet value reduced by depreciation is lower than the asset's net present value in accordance with the methodology, so the DSO retains the incentive for reintroducing the asset.

As a rule, the transfer of assets is not part of the electricity distribution network business. Based on the Energy Authority's view, as a rule, the criteria for obtaining a return on network assets that have been decommissioned and intended for transfer are not met. The company has already received a return on the asset when it has been used. However, based on the Energy Authority's view, as the Energy Authority considers such assets to be exceptional in companies and as the balance sheet value of such assets is likely to be relatively small due to depreciation, these assets will not be separated from other stored components in the non-current assets.

1.4 Negative financial asset accounts

When the assets side of a balance sheet allocated to the network business is negative, this item is actually business debt. Business debts should primarily be allocated to the liabilities side of the balance sheet, but negative items may end up on the assets side of the balance sheet as a result of unbundling. This may be because the balance of a group bank account may be positive for the company as a whole, but negative for an individual business operation. Since the balances of the unbundled accounts must correspond to the balance of the company's account, even a negative account balance must be entered in the assets side of the balance sheet. However, including the balance in the assets side of the balance sheet does not mean that it is not actually a debt. Therefore, the negative balance included in the financial assets must be corrected for non-interest-bearing debts.

The reasonable costs of financial assets are calculated on the basis of the receivables on the assets side (excluding trade receivables). As a negative financial asset account is debt, the negative balance can be considered as reducing the total balance of receivables and thus also the reasonable costs of financial assets in an unfounded manner. Therefore, negative accounts for financial assets are not taken into account when calculating the reasonable costs of financial assets.

1.5 Demolition costs of replacement investments in network assets

In the regulation methods in the fourth and fifth regulatory periods, it has been possible to take into account the demolition costs of replacement investments in network assets in the adjusted invested assets in the unbundled balance sheet values. The regulation methods for the fourth and fifth regulatory periods noted that this leads to the equal treatment of DSOs regardless of whether the demolition costs have been recorded as costs or capitalised on the balance sheet.

However, taking capitalised demolition costs into account in their balance sheet value means that they are not subject to an incentive to minimise costs (efficiency incentive). By contrast, demolition costs treated as costs have been subject to the efficiency incentive as they have been taken into account as part of the controllable operational costs (KOPEX) and their reference level (SKOPEX).

The cost frontier to be used as the reference level for the efficiency incentive is determined on the basis of the realised controllable operational costs of past years. Meanwhile, when calculating the efficiency incentive's annual incentive impact, the actual controllable operational costs for the given year are always taken into account. Consequently, companies that have not recorded the demolition costs as costs may have benefited from the demolition costs recorded by other companies through the higher SKOPEX value. However, these companies have not incurred the same costs once the demolition costs have been capitalised, and their KOPEX has been lower as a result. The DSOs that have capitalised their demolition costs have therefore gained an additional benefit in addition to the reasonable return calculated on the balance sheet value through the efficiency incentive based on demolition costs recorded by other DSOs as costs.

The demolition costs of replacement investments have not been taken into account in the unit prices of network assets. The same procedure will be used in the sixth and seventh regulatory periods. Taking the costs into account in the unit prices would lead to an increase in unit prices also for those network components and companies that are not subject to the demolition costs of replacement investments. Demolition costs of replacement investments were reported by 26 companies in the 2021 financial statements. The method would therefore lead to an unjustified increase in the basis of return for a large number of companies. Due to the individuality and case-specific nature of demolition costs, the formation of unit prices is also very challenging in practice. In addition, the Authority considers that demolition costs concern such costs that should, as a rule, be taken into account as an expense, if possible. It is irrelevant to the market value of the network whether or not sections of the old network have been demolished to make room for the new network. The Authority also considers that there are no justifications for allowing reasonable returns and depreciations for demolition.

The demolition costs of replacement investments must be included in full in the efficiency incentive to make the principle more equal and justified in terms of cost management both in general as well as between different DSOs. As a result, the capitalised demolition costs of replacement investments in network assets will be adjusted in the reasonable return calculations in the sixth and seventh regulatory periods as if they had been entered as expenses. The demolition costs recorded as expenses in accounting will be taken into account as operational costs as previously.

The capitalised demolition costs of replacement investments in the balance sheet regarding network assets will be eliminated from the adjusted balance sheet. Similarly, depreciations related to these demolition costs are returned to the adjusted result. The demolition costs of replacement investments regarding network goods are not included in the adjusted replacement value or adjusted net present value of network assets. Also, no RCV straight-line depreciation will be calculated for these.

The demolition costs of replacement investments in network assets capitalised during the financial period are deduced from the profits and controllable operational costs (KOPEX) and the general efficiency target reference level (SKOPEX).

During the sixth (2024–2027) and seventh (2028–2031) regulatory periods, annually 1/8 of the balance sheet value of the capitalised demolition costs of replacement investments in network assets in accordance with the 2023 financial statements will be deducted from the operating profit. As a result, the demolition costs capitalised on the balance sheet by the start of the regulatory period will be taken into account as expenses by the end of 2031. As these costs have already been realised before the start of the regulatory period, the demolition costs capitalised before 2024 will be taken into account as non-controllable operational costs that are not covered by the efficiency incentive.

1.6 Subsidies received for the construction of the network

According to the regulation methods of the fourth and fifth regulatory periods, any components financed by subsidies or compensations have been taken into account in the adjusted replacement value of electricity network assets when this is used as a basis for calculating the adjusted depreciations of the electricity network assets in the investment incentive. However, the regulation method has been changed in that the regulation methods of the sixth and seventh regulatory periods will not take the components financed by subsidies or compensations into account in the adjusted replacement value of electricity network assets, when this is used as a basis for calculating the adjusted depreciations of the electricity network assets in the investment incentive.

From the point of view of network users, there is no justification to finance this investment cost through the costs of either reasonable return or adjusted profit (straight-line depreciation), as the components have already been fully compensated to the DSO by the subsidy.

The opinions for the 1st guideline highlighted a need to specify the processing of compensations related to line transfers in relation to the processing of subsidies received for the construction of the network referred to in the method. With regard to the subsidies received for the construction of the network, the Energy Authority has specified that the compensations received for the costs of line transfers will not be treated as subsidies received for the construction of the network in the regulation methods.

2 Reasonable rate of return

2.1 Model for weighted average cost of capital

The method used when determining a reasonable rate of return approved for adjusted capital invested in network operations is the Weighted Average Cost of Capital, or the WACC model

The WACC model indicates the average cost of capital used by the company, weighted by the relative values of equity and debt. The average cost derived from the use of reference companies reflects the level of alternative cost that should be allowed for the fixed capital when comparing an alternative investment project with a similar capital structure and risk level. This ensures a reasonable but sufficient return on the capital employed in the business of the network companies.

In 2022, the Energy Authority commissioned an external report from KPMG Oy Ab on the determination of a reasonable rate of return[7], which has been a key source for assessing methodological changes.

2.2 Reasonable cost of equity

When determining a reasonable rate of return, the reasonable cost of equity is calculated with the Capital Asset Pricing Model, or the CAP model. The model determines the alternative cost based on expected returns proportioned to risks. The model is therefore not concerned with a real cost, but an expected return, which is assumed to correspond to a reasonable alternative cost allowed for capital.

The CAP model describes the dependency between the investment project's required rate of return and risk. It is a forward-looking model that describes the expected return for a risky investment project for the investor in relation to a risk-free investment project.

The CAP model is an internationally widely applied method of defining the expected return on capital in regulated sectors, which has also been deemed suitable by the Market Court.

2.2.1 Risk-free rate of equity and debt and country risk premium

In the CAP model, the return requirement of an investee that is as risk-free as possible should be applied as the risk-free interest rate. In general, the bonds of countries that carry a high (AAA) credit rating are considered such investees. In 2015, Finland's credit rating was updated by S&P from AAA to AA+, where it has remained since then. Germany is therefore the most relevant AAA-rated state, whose bond loan rate is applied as a risk-free interest rate.

As the equity investment horizon must be several years in network operation, the selection of maturity, i.e. the lifetime of the loan, is key. Therefore, the use of long-term bond returns to determine the risk-free interest rate is justified. For the 6th and 7th regulatory periods, the 10-year government bond interest rates in the state of Germany will be applied as the risk-free interest rate. The use of the 10-year maturity is also supported by a previous expert statement requested by the Energy

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[7] KPMG Oy Ab, Selvitys kohtuullisen tuottoasteen määrittämisestä sähkö- ja maakaasuverkkotoimintaan sitoutuneelle pääomalle (Report on determining a reasonable rate of return for capital committed to electricity and natural gas network activities), 20 September 2022

Authority from Juha-Pekka Kallunki, Professor of Accounting at the University of Oulu's School of Business[8].

The country risk premium aims to take into account the risk that a country with a lower rating is more likely to neglect its bond obligation compared to an AAA-rated country. Although taking country risk into account is a controversial topic[9], where the possibility of decentralisation from the owner's perspective is at stake, the regulated electricity distribution network operations and high-voltage distribution network operations are exclusively concerned with Finland. As a result, the Energy Authority finds that there are criteria for taking into account the risk premium between Finland and Germany as a separate country risk premium for the costs of both equity and debt. An external report by KPMG also recommended the application of the country risk premium.

Based on the KPMG report's recommendation, the country risk premium should be derived from Professor Damodaran's data bank, which is updated annually. However, KPMG also noted in a subsequent response that the country risk premium can be calculated as the difference between the interest rate on Finnish 10-year bonds and the interest rate on German loans with an equivalent maturity. This latter method takes Finland's country risk into account in more detail in relation to other countries with a similar credit rating (AA+) and fares better at reflecting the period under review selected in the context of the risk-free interest rate. These factors support the determination of the country risk premium using this method.

2.2.2 Beta coefficient

The beta coefficient describes the risk element of the enterprise under review in

relation to the average risk element in all investments and it is a key parameter in the CAP model when determining the expected return on equity.

The beta coefficient depends on the cost structure, debt ratio and growth of the enterprise. In practice, this results in a convergence of the betas of enterprises operating in the same industry.

The regulation methods are based on the fact that the beta coefficient is a sector-specific quantity and it describes the risk level of investments made in enterprises in the electricity network sector in comparison with all investments in the stock market. According to the Authority's views, there are no sufficient justifications for

[8] Kallunki (2021) Lausunto jakeluverkkotoiminnan valvontamenetelmissä käytetyn riskittömän korkokannan määrittäminen (Statement on the determination of the risk-free interest rate used in the regulation methods of distribution network operations)

[9] Damodaran (2022) Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – The 2022 Edition

applying a separate reference group to high-voltage electricity distribution network operations in relation to electricity distribution network operations.

Enterprises engaged in regulated electricity distribution network operations have been used as the reference group for electricity distribution network operations and high-voltage distribution network operations. None of the enterprises used as reference companies is purely focused on the distribution of electricity, but all of them also have other business activities at a group level. It is not possible to distinguish between the level of risk (beta) in the business operations based on separate operations within reference companies.

The asset beta describes the risk of business operations without the risk arising from indebtedness. In the regulation methods, the asset beta has been calculated with the Hamada formula, in which the impact of the tax rate is also eliminated. The application of the Hamada formula is based on the practices of the previous methodological period, on which the EC commented in its external report in 2014.[10]. The KPMG external report did not comment on the application of the formula, and the Energy Authority does not see any justification for applying another method for taking the tax rate into account.

At the recommendation of the KPMG's expert report, the so-called Blume adjustment is applied to the beta coefficient, which involves adjusting the raw betas of the reference companies using the formula: $\beta_{oikaistu} = \frac{2}{3} \times \beta_{oikaisematon} + \frac{1}{3} \times 1$,

where the raw asset beta has been adjusted by weighting it with one third of the average market risk. In KPMG's view, this is a common practice used in valuation, and in interpreting the practices of regulators at the European level, the Energy Authority has noted that this so-called 'adjusted beta' is a commonly applied practice, as raw asset betas derived from reference companies would be much closer to zero.

2.2.3 Market risk premium

The market risk premium describes the difference between the risk-free interest rate and the return on equity investment, i.e. the degree to which the shares have yielded a return exceeding the risk-free rate.

The market risk premium can be defined in several ways: based on historical returns, based on surveys targeted at financing professionals, and based on implicit

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Ernst & Young Oy (2014), Kohtuullisen tuottoasteen määrittäminen sähkö- ja maakaasuverkkotoimintaan sitoutuneelle pääomalle (Report on determining a reasonable rate of return for capital committed to electricity and natural gas network activities) valuation factors. The view of the Energy Authority involves applying the method recommended by KPMG in its external report to apply the so-called implicit market risk premium, which is derived as the difference between the market return expectation and the risk-free interest rate of a country with an AAA credit rating (USA). While a statement received by the Energy Authority requested that the Authority should apply the risk-free interest rate of Germany to determine the market risk premium, based on the Energy Authority's view, this procedure would be inconsistent when the expected market return is derived from the Damodaran database on the basis of the expected market return for the United States. At the same time, the KPMG study also notes a uniform that an equity market risk premium has been assessed for the AAA-classified countries in the Damodaran database. In addition, the Energy Authority is of the view that country-specific differences in the market risk premium have been taken into account in the country risk premium.

2.2.4 Premium for lack of liquidity

The premium for lack of liquidity describes any illiquidity of an investment.

Factors having a reducing impact on the value of ownership of a company that is unlisted or has a lack of liquidity for another reason may include higher transaction costs and a longer sale period than the ownership of a listed company.

Efforts have been made to use different methods for modelling the premium for lack of liquidity when determining the value of an enterprise. However, it has not been possible to select a single generally accepted method for the calculation. Therefore, the practical application of the premium is extremely discretionary. An external study commissioned from KPMG also notes that, as the assets of the network business operations subject to regulation by the Energy Authority can be considered low-risk, applying a premium for lack of liquidity that is at most moderate is justified in determining a reasonable rate of return.

A moderate level of premium for lack of liquidity is supported by the licence requirements of network operations and the significant acquisitions carried out in the sector even in the past few years.

When assessing the level of the premium for lack of liquidity, it must also be taken into account that the enterprises in the sector are mainly majority-owned. This means that the owners have control of the enterprises and can therefore directly affect the business operations of the enterprises.

The value of the premium for lack of liquidity has been dealt with in several statements [11, 12, 13, 14] in addition to the decision on the Market Court (MAO:271–344/2006). The value of the premium can be determined as an average of the values presented in these statements. Based on currently available information, the Energy Authority does not consider that there are grounds to change the liquidity premium from the previously applied 0.6%.

2.2.5 Capital structure

The capital structure describes the weightings of the cost of equity and the cost of debt in the WACC model.

The capital structure also has an impact on the determination of the beta coefficient. In order to bring the beta coefficients of various shares into a commensurable form, the impact of the capital structure of the enterprise must be eliminated.

The previous methods have applied a uniform assumption of capital structure to the sector in calculating the capital-weighted average cost. The assumption has been derived based on the market value of listed reference companies whose business resembles the examined enterprises as closely as possible. This is a commonly applied practice, also at the international level. It is assumed that these companies have optimised their capital structure to maximise the value of the company. The KPMG study also stands in favour of using this approach, as it ensures the market conformity of the reasonable returns requirement.

Some opinions obtained from stakeholders expressed the need to apply a company-specific capital structure, which should be based on equity and interest-bearing debt shares in accordance with the company's balance sheet. In the case of listed companies, the capital structure of the company in accounting may differ significantly from the capital structure based on the company's market value and therefore, this may also not be used as the basis for determining the rate of return in the regulated DSOs. It is also noteworthy that the company's debt ratio also significantly affects the return on equity requirement. As Finnish electricity distribution

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[11] Martikainen Teppo, Lausunto Sähkömarkkinakeskukselle jakeluverkkotoimintaan sitoutuneen pääoman kohtuullisesta tuottoasteesta (Statement to the Electricity Market Centre on the reasonable rate of return on capital invested in distribution network operations), 4 November 1998

[12] PricewaterhouseCoopers, Lausunto koskien sähkön jakeluverkkotoiminnan pääoman keskikustannusta (Statement on the average costs of capital in the electricity distribution network operations), 7 April 2004

[13] Deloitte & Touche, Energiamarkkinavirasto – Sähköverkkotoiminnan WACC-mallin ja sen parametrien arviointi (Assessment of the WACC model and its parameters in electricity network operations), 6 August 2010

[14] Kallunki, Juha-Pekka, Lausunto Energiamarkkinaviraston käyttämästä sähköverkkotoiminnan valvontamallista (Statement on the regulatory model for electricity network operations used by the Energy Market Authority), 29 April 2011

or high-voltage electricity distribution companies are not listed, the Energy Authority cannot apply an enterprise-specific capital structure derived from the market value.

2.3 Reasonable cost of debt

When determining a reasonable rate of return, the reasonable cost of debt is calculated by adding the country-risk ratio and debt premium to the risk-free rate. Some opinions received from the stakeholders expressed a need to apply the realised accounting cost of debt of the companies subject to regulation in determining the cost of debt. Based on the Authority's view, this method would mean moving away from the commonly applied WACC model, where a reasonable return is averaged by optimal weightings of the relative shares of equity and debt, and a separate rate of return is applied to equity[15]. There is also a risk that this change would lead to inefficient loan conditions for debt or result in companies arranging their financing within their group so that the costs of debt would be unreasonable. In addition, it would not be possible to limit the cost of debt based on an optimal capital structure, as the companies subject to regulation are not listed and their market value, which would be used as the basis for setting limits to the allowed costs of debt, would thus be unknown.

2.3.1 Debt premium

The debt premium describes the cost of the funding of debt on top of the risk-free rate.

Based on the report commissioned from KPMG, the debt risk premium should be based on the most recent information, and the level has been estimated as the average of the 10–30-year bond yields issued by reference companies at the time of the update, after deducting the 10-year risk-free interest rate of the most relevant country with AAA credit rating, depending on the bond issued by the reference company.

Even though publicly-listed bonds can be found for network companies engaged in electricity distribution network operations in Finland (Elenia Verkko Oyj and Caruna Oy), which can be used to determine the interest-bearing debt premium, the Energy Authority has applied the same reference companies as those applied in determining the other parameters of the WACC model based on the recommendation of KPMG. This strengthens the consistency of the parameters applied in the model.

[15] However, some countries, such as the united states, apply realised costs of debt (https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf)

2.3.2 Debt premium and country risk

KPMG's external report also recommended that the country risk premium should also be applied when determining the reasonable cost of debt. Based on the assessment method applied by KPMG, the Energy Authority's view is that the country risk premium must be applied with careful consideration, as the business of some reference companies is located in countries with AAA credit ratings, in which case the country risk premium of the country where the business is focused should have been deducted from the coupon rate on bonds used to calculate the debt premium. The response received from KPMG notes that bonds listed in a non-AAA-rated country may include an implicit country risk premium, but an examination of the used bonds shows that most of these are located in AAA-rated countries, which means that, based on this sample, the country risk must be added to operations located in Finland. In addition, based on an internal assessment by the Energy Authority, the elimination of any implicit country risk in reference companies' loans cannot be carried out in a straightforward manner by deducting the difference between the interest rate in the below-AAA-rated country where the business activities are focused and the interest in the most relevant AAA-rated country. The calculation method would lead to inconsistently low debt premium levels for individual loans.

2.4 Calculation of a reasonable rate of return and consideration of taxes

Total capital cost is calculated with the average weighted costs of equity and interest-bearing debt. The returns requirement of non-interest-bearing debt is zero, and therefore it is not necessary to include it in the calculation of a reasonable rate of return.

A reasonable pre-tax rate of return is used in the regulation methods. That way, corporate tax is taken into account in the calculation of a reasonable return and it is not deducted in the calculation of realised adjusted profit. The application of a reasonable pre-tax rate of return clarifies the regulation methods and puts the DSOs in an equal position regardless of their company form or group structure.

2.5 Frequency of updating regulation parameters and the period under review

Based on KPMG's external report, the applicable parameter values should, in principle, be based on the most recent data and the report provided recommendations on the update frequency of the parameters and determined the information for the time period which should be used as the basis for calculating the parameters for each regulatory year. However, the continuity, predictability and long-term nature of the regulatory methods must be taken into account in the decision-making on the methods. At the same time, the need for updating certain parameters, such as risk-free interest, is higher, as the prevailing market conditions can suddenly affect interest rates and, consequently, the reasonable rate of return.

2.5.1 Frequency of updating the regulation parameters

The external report by KPMG categorised the regulation parameters in order of priority into three categories, depending on their sensitivity to market conditions and economic fluctuations:

- High: beta coefficient, risk-free and debt risk premium
- Average: capital structure
- Low: market risk premium, country risk premium, lack of liquidity premium

The Energy Authority has used this categorisation as a starting point when considering the frequency of updating different parameters. However, factors in favour of a higher update frequency include the practical implementation of the update and the general predictability and long-term nature of the regulation methods. As a whole, the Energy Authority considers it necessary and practical to update the parameters according to the following schedule starting at the beginning of the regulatory period:

Once per year: risk-free interest rate and country risk premium

Once every two years: beta coefficient, capital structure[16] and debt risk premium

Once every four years: market risk premium

Not to be updated during the regulatory period: premium for lack of liquidity

In the previous regulatory period 2016–2023, the risk-free interest rate was updated annually, and the debt risk premium between the regulatory periods (every four years) and other parameters remained the same throughout the regulatory period.

A key area to the regulatory methods is to guarantee an adequate but reasonable return on capital employed in the business. Thus, the reasonable rate of return of the methods should reflect the actual business risk situation during the regulatory period and the reasonable costs of financing as accurately as possible, also as market conditions are changing. This favours the use of the most recent information, especially for parameters that are more sensitive to economic fluctuations. This

[16] Although the capital structure may be less sensitive to economic fluctuations than some other parameters, the Energy Authority considers it necessary to update the optimal capital structure in the same context as the beta coefficient so that the calculated equity beta reflects the situation at the time of the update.

justification plays a key role in why it is important to update the risk-free interest rate annually and the parameters derived from the reference companies (beta coefficient, capital structure and debt risk premium) every two years. This ensures that no gap is formed between the parameters and the reality of the market situation during the regulatory periods.

At the same time, ex-ante, not ex-post, regulation is used, meaning that the parameters of the regulation model must be known before the start of the regulatory year. This sets certain limits to how recent the information used as the basis of the parameters in the regulation methods can be and causes a delay in how soon the changing market conditions will be reflected in regulation and the permitted return.

2.5.2 Period for reviewing regulation parameters

As part of the definition and update of regulation parameters, it is also necessary to select the used review period, the time period used for setting an average for the applied parameter value.

In its report, KPMG largely applied very short reference periods of one day (capital structure), two weeks (debt premium) or one year (market risk premium[17], beta coefficient based on two years' average) at the time of the update. This was used to make sure that the parameter values reflect the most recent information available at the time of the update. However, KPMG also simultaneously notes that some parameters are more sensitive to economic fluctuations, and based on the view of the Energy Authority, this in itself favours the application of slightly longer review periods, such as six-month periods.

The risk-free interest rate is a particularly volatile variable, and there may even be significant day-to-day changes in situations where the market is experiencing difficulties in pricing ownership items precisely due to factors such as uncertain economic conditions and central banks' economic policies. For this reason, the Energy Authority considers it justified to apply the previously applied six-month review period for this parameter.

With regard to the market risk premium, the Energy Authority considers it justified to harmonise the period under review regarding the risk-free interest rate, which is also used to reduce the weight of an individual month when the parameter is locked for four years based on the recommendation of KPMG. With regard to the other

[17] KPMG recommended the application of the value of the most recent month available in the dataset published by Damodaran, based on the profit, dividends and share buybacks during the latest 12-month period.

parameters, the Energy Authority applies the review periods recommended by KPMG.

2.6 Reference companies and defining the parameters calculated based on them

The choice of the reference group for the definition of WACC parameters is a key part of the process when market-driven parameters are used to determine the reasonable rate of return applied in the methods. The reference group is based on the recommended group included in the KPMG report, from which the Energy Authority has removed the companies Fortum Corporation and RWE AG in connection with internal reviews, which no longer had any relevant business operations at the time the parameters were set based on the information available to the Authority. The final reference group is specified in the methodology appendix 2. The reference group also includes companies that have announced their intention to reduce or sell all their shares in network business, such as SSE and EDF, which is in the process of nationalisation.

Based on an internal report of the Energy Authority, the reference companies' business endeavours at the group level also include activities other than regulated network business operations. The assessment of the relevance of the reference group for electricity distribution network operations and high-voltage distribution network operations is presented in Table 1, and, as can be seen, the share of the relevant network business operations in the group's total turnover remains low for some companies. These other business operations, which are market-based, may affect issues such as the level of risk in the business and thus the parameters derived from the companies (beta coefficient, capital structure and debt premium). However, based on the internal additional assessment of the Energy Authority and the opinions received from stakeholders, there are no sufficient justifications for deviating from the sample median in selecting the parameter values and applying, for example, the lower or upper quartile of the sample range, as the share of regulated network business in the group's turnover does not unambiguously explain the deviation between the reference companies in the sampling of parameter values. The samples are also relatively limited as a rule.

Reference company	The percentage (%) of relevant network business of the group's turnover	Source (group's annual report)
E ON SE	17%	2022 p. 280
Edison International	52%	2022 p. 24 and 98
EDP Energias de Portugal SA	16%	2022 p. 362

Electricite de France SA	12%	2022 p. 26
Enel SpA	16%	2022 p. 195
Iberdrola SA	34%	2022 p. 67
SSE PLC	18%	2022 p. 226
Average	**24%**	

***Table 1**: Reference group for electricity distribution network operations and high-voltage distribution network operations and assessment of its relevance*

The parameters of a reasonable rate of return will be updated during the methodology period using a predefined reference group. This will set requirements that the applied reference companies must also have relevant network business operations in connection with the update.

3 Incentives

3.1 Quality incentive

The aim is to retain the basic structure of the quality incentive used in the previous regulatory periods during the 6th and 7th regulatory periods. Any changes in the incentive are mainly related to bringing the parameters used, i.e. unit prices and indicator data, up to date.

3.1.1 Updating DCO unit prices

From 2008 until 2023, the quality incentive applied the unit prices set for the disadvantage caused by outages using indexation. The prices were based on studies conducted in 2005[18], 2006[19] and 2007[20]. The next methodology period extends to the period 2024–2031 when the number of years between the years under review and the studies underlying the applied unit prices is up to 26 years. In such a long period, the electricity use of the DSOs' customers will have changed significantly, and the disadvantages described in old studies may not reflect the current disadvantage caused by outages. The unit prices based on the above reports have also been defined in the monetary value of 2005, in which case unit prices would have to be indexed by 26 years in 2031.

Due to the above justifications, the Energy Authority decided in summer 2022 to order a report from AFRY Management Consulting Oy on the costs[21] of the disadvantage caused by outages, according to which the unit prices of the disadvantage caused by an outage based on the latest research data will be presented in the regulation methods for electricity distribution network operations during the 6th and 7th regulatory periods.

3.1.2 Low-voltage network outages

In 2015, the Energy Authority started collecting energy-weighted key figures on the numbers and periods of outages in the low-voltage network from the DSOs as a result of the regulation on the key figures of electricity network operations and their publication (1730/002/2015). No amendments relevant to this topic have

[18] Helsinki University of Technology, Tampere University of Technology / Silvast Antti, Heine Pirjo, Lehtonen Matti, Kivikko Kimmo, Mäkinen Antti, Järventausta Pertti, Sähkönjakelun keskeytyksistä aiheutuva haitta (Disadvantage caused by outages in electricity distribution), 12/2005

[19] Lappeenranta University of Technology / Honkapuro Samuli, Tahvanainen Kaisa, Viljainen Satu, Lassila Jukka, Partanen Jarmo, Kivikko Kimmo, Mäkinen Antti, Järventausta Pertti, DEA-mallilla suoritettavan tehokkuusmittauksen kehittäminen (Development of efficiency measurement using the DEA model), 12/ 2006

[20] Lappeenranta University of Technology, Tampere University of Technology / Honkapuro Samuli, Tahvanainen Kaisa, Viljainen Satu, Partanen Jarmo, Mäkinen Antti, Verho Pekka, Järventausta Pertti, Keskeytystunnuslukujen referenssiarvojen määrittäminen (Determination of reference values for outage indicators), 5/2007

[21] AFRY Management Consulting Oy / Tkachenko Evgenia, Vihavainen Petri, Selvitys keskeytyksen aiheuttaman haitan kustannuksista, (A report on the costs of the disadvantage caused by outages), November 2022

been made to the currently valid regulation on the key figures of electricity network operations and their publication (2167/002/2016).

From the 6th regulatory period onwards, the key figures on outages in the low-voltage network will also be taken into account in the calculation of the quality incentive for electricity distribution system operators. From the perspective of the DSOs' customers, the part of the DSO's network from which an outage originates does not affect the perceived disadvantage. Therefore, there are grounds for taking the outages in the low-voltage distribution network into account in the calculation of the quality incentive in a manner consistent with the medium-voltage and high-voltage distribution networks.

3.1.3 Energy weighting of the high-voltage distribution network

As a result of the above-mentioned regulations on the key figures for electricity network operations and their publication, the Energy Authority has begun to collect from distribution system operators and high-voltage distribution system operators both average outage key figures for access points as well as average energy-weighted outage key figures for access point outages since 2018.

From the 6th regulatory period onwards, the calculation of the quality incentive for different voltage levels will be harmonised by also using energy-weighted outage key figures for the high-voltage distribution network. The energy weighting in the outage key figures is proportional to the number and duration of outages according to the amount of energy used by the access points, which better reflects the actual disadvantage caused by the outage. The use of energy weighing in the quality incentive for the high-voltage distribution network was recommended, for example, in a Master's thesis completed for the Energy Authority in 2013[22] and in a report commissioned by the Energy Authority from Gaia Consulting Oy on the functioning and development needs in the quality incentive in the period 2016–2023[23].

3.1.4 Planned outages in the high-voltage network are not taken into account in the quality incentive

The Energy Authority has collected information on planned interruptions in the high-voltage network. Due to the nature of the customers in the high-voltage network, the imputed disadvantage caused by the planned outages does not always reflect

[22] Heikkilä, Tuukka, Sähköverkon toimitusvarmuuteen liittyvien valvontamenetelmien kehittäminen (Development of supervision methods related to the security of electricity supply), 9 October 2013

[23] Gaia Consulting Oy, Karttunen Ville, Vanhanen Juha, Partanen Jarmo, Matschoss Kaisa, Bröckl Marika, Haakana Juha, Hagström Markku, Lassila Jukka, Pesola Aki and Vehviläinen Iivo, Selvitys laatukannustimen toimivuudesta ja kehitystarpeista vuosille (Report on the functioning and development needs of the quality incentive for the period) 2016–2023, 27 October 2014

the actual disadvantage caused to customers. As a rule, the DSOs agree on interruptions together with the customers, enabling the customers to schedule their own service downtime, installations and other measures requiring electricity-free time to take place during the planned outages. In addition, planned outages in the quality incentive of transmission system operators are also not taken into account, and the exclusion of planned outages in the high-voltage distribution network from the quality incentive harmonises the regulation of the different high-voltage network types by the Energy Authority.

Additionally, based on simulations carried out with DSOs, the exclusion of planned outages has a diminutive impact on the overall impact of the incentive.

3.1.5 Years used in the reference level

Since the 4th regulatory period, the Energy Authority has been applying an eight-year reference level in the quality incentive. The eight-year reference level is widely recommended in studies related to the quality incentive, such as the above-mentioned report by Gaia Consulting Oy and the opinion[24] of the Academic Working Group appointed by the Ministry of Economic Affairs and Employment, which notes as follows: "As faults, especially major disruptions, occur only sporadically, the current eight-year time span in the historical data provides a reliable view of the actual level of outage costs and the company's operating environment. This has also been decided in an earlier report (Honkapuro 2007). The duration of a single regulatory period does not suffice in providing an adequate picture of the level of outage costs corresponding to the actual operating environment."

To ensure that the applicable reference level would reflect the relevant outage history data of electricity distribution companies as far as possible, the most recent eight-year reference level available will be applied in the 6th and 7th regulatory period similarly as in the previous regulatory periods. Therefore, the reference level consists of the period 2016–2023 in the 6th and the period 2020–2027 in the 7th period. For the high-voltage distribution network, the reference level of the period 2018–2023, i.e. a six-year reference level, will be exceptionally used in the 6th regulatory period. This is done due to the transition to using energy-weighted outage data, which the Energy Authority has been collecting from the DSOs since 2018. The Authority will switch to using the eight-year reference level also for the high-voltage distribution network in the 7th regulatory period.

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[24] Järventausta Pertti, Collan Mikael, Liski Matti, Huhta Kaisa, Akateeminen työryhmä sähkönsiirron ja –jakelun tariffien laskentamenetelmistä, työryhmän lausunto Energiavirastolle (Academic working group on tariff calculation methods for electricity transmission and distribution, working group statement to the Energy Authority), 31 May 2022

3.1.6 Ensuring a reasonable reference level

In the methods, the amount of the disadvantage caused by outages has been made more reasonable in terms of realised costs since the introduction of the quality incentive, i.e. 2008. This has limited the impact of the quality incentive in years of major disruptions to the ceiling and floor levels defined in the methods, which currently account for 15% of the DSO's reasonable return for the year in question. However, the disadvantage caused by outages in the years in question has been taken into account in its entirety in the reference level for the quality incentive during previous regulatory periods.

Ensuring a reasonable reference level has been particularly discussed in the opinion of the academic working group appointed by the Ministry of Economic Affairs and Employment. As noted in the opinion "Reasonable adjustment used in the quality incentive (the effect may be at most 15% of the permitted result) can be justified to ensure that the quality sanction for an individual bad year does not become excessive from the network company's perspective. However, the outage cost of an individual year is used as such in calculating the reference level. In practice, this can mean that even if it is ensured that the impact of a major disruption is reasonable for the network company, customers will pay an additional return for the outage they experience for the network company for several years through a higher reference level, which does not correspond to the original purpose of the quality incentive. In fact, the current method of calculating the reference level may reduce the incentive effect of the quality incentive for the electricity distribution network company."

Furthermore, according to the opinion of the academic working group, "However, we may note that the quality incentive is used specifically calculating the realised adjusted profit based on the operating profit, affecting the profit by either increasing or reducing it, in which case ensuring reasonable outage costs would be well justified and would then describe the exact correct reference level for the quality incentive in the calculation of operating profit. In addition, the formation of actual outage costs should be monitored separately as a part of the monitoring and regulation of quality together with other key figures describing reliability. It should also be noted that in any case, the outage cost is in itself a fictitious value that describes the disadvantage caused to customers by the interruptions and does not represent an absolute cost in euros. In addition, outage costs do not reflect the costs incurred by the electricity distribution network company, but specifically refer to the quality of the network service experienced by the customer."

If the impact of exceptionally high annual outage costs is limited only in the calculation of the realised adjusted profit of the regulation methods and not in the calculation of the reference level, the incentive does not work as desired after the ceiling level has been exceeded and will instead direct the DSOs to increase the outage costs for that year. With the method for defining the reference level that takes the maximum impact into account, the incentive works neutrally for outages that exceed the ceiling level, in which case customers do not have to pay extra returns to DSOs for the exceptionally high number and durations of outages they experience, but no sanctions are imposed on the DSOs due to these either.

From the seventh regulatory period onwards, the amount of disadvantage caused by outages in individual years in the reference level of the quality incentive for DSOs will be adjusted to be reasonable in the same way as realised costs. As a result, if the incentive impact of the quality incentive for the reference year is limited to the ceiling level according to the methodology in the year when the impact was realised, i.e. it is at most 15% of the DSO's reasonable return for that year, the reference level adjusted to be reasonable will consist of the reference level and incentive impact as a sum for that year, i.e. may be at most 15% of the DSO's reasonable return for that year. Similarly, for the sake of symmetry, if the incentive impact of the quality incentive for the reference year is limited to the floor level according to the methodology in the year when the impact was realised, the reference level adjusted to be reasonable will consist of the difference between the reference level and 15% of the DSO's reasonable return for that year.

The application of the practice for ensuring a reasonable reference level will only begin during the seventh regulatory period, as the security of supply in the period 2016–2023 used as the reference level for the sixth period has been on a steady and good level and there is, therefore, no need for adjusting the level to be reasonable. Meanwhile, in the seventh regulatory period, ensuring a reasonable reference level will eliminate the risk that any unusual security of supply levels in the new reference period 2024–2027 would unduly increase or reduce the reference level of the quality incentive.

To illustrate the procedure for ensuring a reasonable reference level, Figure 1 below shows the realised outage costs of an imaginary company in the period 2020–2027 and the reasonable outturns used in calculating the reference level for the quality incentive in the seventh regulatory period, i.e. 2028–2031. The figure shows that the realised outage costs of 2021 have fallen below the floor level of the incentive, which is why a reasonable outturn is used in the calculation of the reference level, which is limited to the floor level. Similarly, the realised outage costs of 2024 have exceeded the ceiling level, so the incentive uses a reasonable outturn limited to the ceiling level for that year. In the other years, the incentive impact has been between the floor and ceiling levels, so the realised outage costs for those years have not been adjusted to be reasonable.

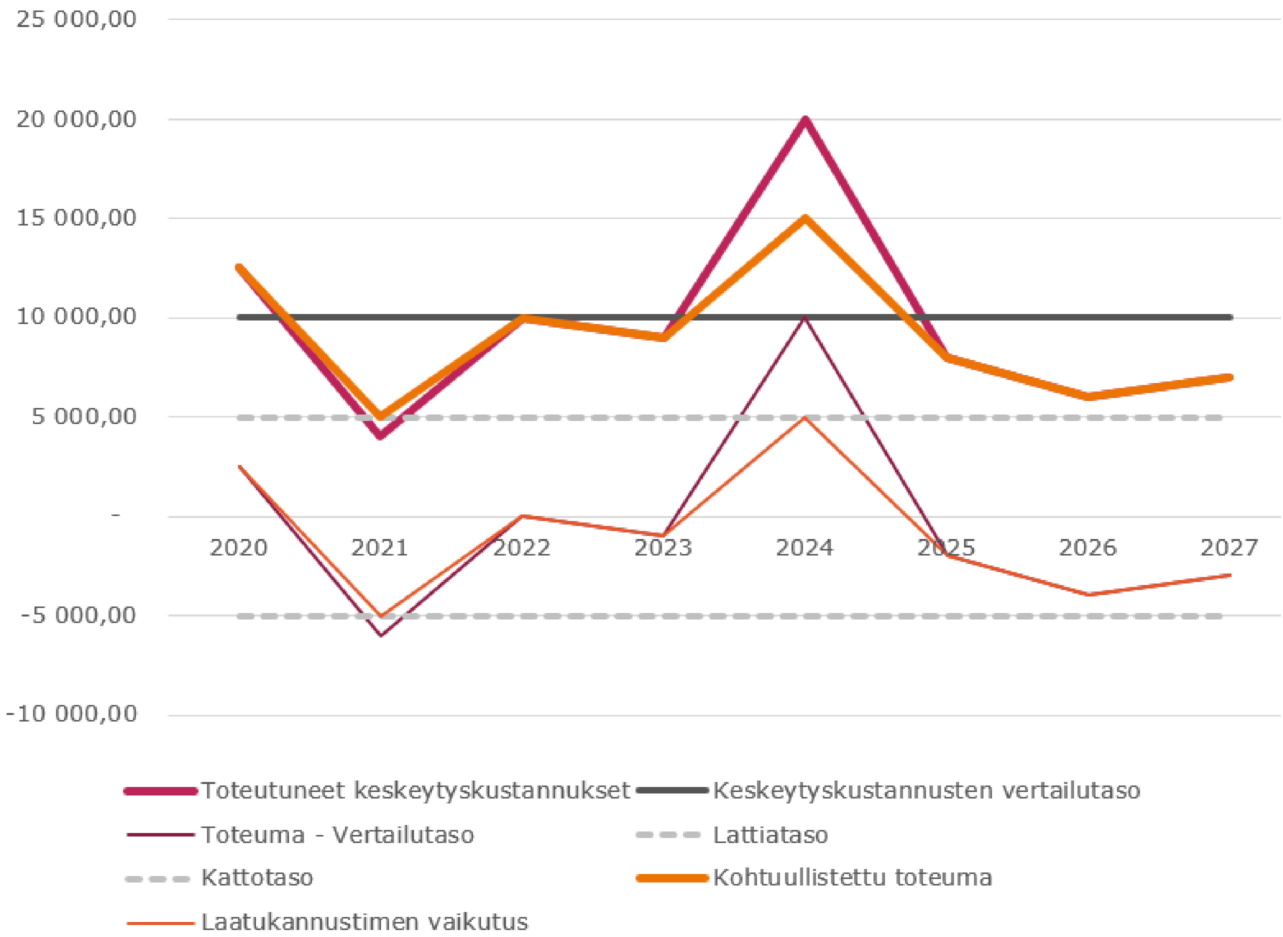

*Figure **1**: An imaginary example of ensuring a reasonable reference level.*

3.2 Efficiency incentive

3.2.1 Description of the current method

The incentives for the regulation methods of electricity distribution network operations include an element that examines operational efficiency, whose purpose is to guide network operators to operate in a cost-effective manner. Network operations can be considered efficient when the inputs used in the operations are as low as possible in relation to the outputs obtained. The efficiency incentive is based on the DSO’s variable costs, i.e. controllable operational costs. The potential of an individual DSO to enhance its operational efficiency is identified by comparing the company’s realised costs with the efficient costs of the efficiency frontier.

In the context of electricity distribution network operations, the cost level of effective network operations is assessed using efficiency measurement methods, which involves estimating the efficiency frontier, which describes efficient operations, on the basis of the input and output data of all DSOs. As the cost frontier model applied to electricity distribution network operations and the estimation method applied to it is in itself complex, including a large number of estimated parameters, the Authority deems it appropriate to provide information about the currently applied model at a slightly more detailed level.

First, an overview is presented of the economic theoretical framework of the current efficiency incentive model. Subsequently, changes proposed to the model for the sixth and seventh regulatory periods are discussed and the grounds for the changes are presented. Finally, the results of the preliminary estimation of the sixth regulatory period are briefly presented.

3.2.1.1 Including the development of the efficiency incentive in the regulation methods

The Energy Authority has been developing efficiency measurement as a part of the supervision of electricity distribution network operations since 1998 and commissioned numerous studies and expert reports related to efficiency measurement. The Energy Authority has consistently sought to develop the applied model on the basis of the latest research data and the experience gained from the practical application of the model. Consequently, the methodology, model specification and variable choices used in the estimation of the efficiency frontier have also been altered or supplemented during different regulatory periods.

The efficiency incentive was included in the incentive mechanism of the regulation methods for DSOs and the calculation of reasonable returns as the Energy Authority moved to advance regulation carried out in regulatory periods in 2005.

3.2.1.2 The economic theoretical framework for the current cost frontier model

The method currently applied by the Energy Authority to assess a reasonable operative cost level is based on the yardstick competition established in the research literature on the topic, which involves creating a framework for cost competition between monopoly companies that do not encounter cost competition due to the nature of their operations or legislation. The most commonly applied yardstick competition practice in the network sector is based on the modelling of variable costs (or operational costs, OPEX) or total costs (operational costs + capital costs, TOTEX) in line with efficient operation.

The regulation of both operational costs and total costs involves certain problems from the perspective of incentive impacts. A problem may emerge in regulation based on total costs due to the fact that this model assumes that all costs are variable costs and may not take the investment risk sufficiently into account, and may therefore end up holding back necessary capital investments. Network sectors are industries where investment decisions are made to concern several decades, and adjusting capital in the short term is difficult. On the other hand, regulation only based on operational costs may create incentives for network companies to compensate for their operational costs through excessive investments, therefore encouraging excessive investments if no other limits are set to the companies' investments in network capital.

In their report, Kuosmanen & Johnson[25] have proposed the conditional yardstick competition as a solution to the described incentive problem, involving cost competition between network companies in terms of changing costs, while taking network capital into account. In practice, the model therefore takes into account two separate input variables, i.e. operational costs as a variable input, to which an efficiency target is allocated in addition to the network value a fixed input that is not subject to the efficiency target. However, as its name suggests, in a conditional yardstick competition, the level of operative costs in accordance with efficient operations is estimated as conditional in relation to the company's capital. Conditional yardstick competition can therefore be used to mitigate both the problem of overinvestment related to operational costs as well as the problem of limiting investments related to total costs.

[25] Kuosmanen, T., Johnson, A.L., Condition yardstick competition in energy regulation, The Energy Journal 41, 2020

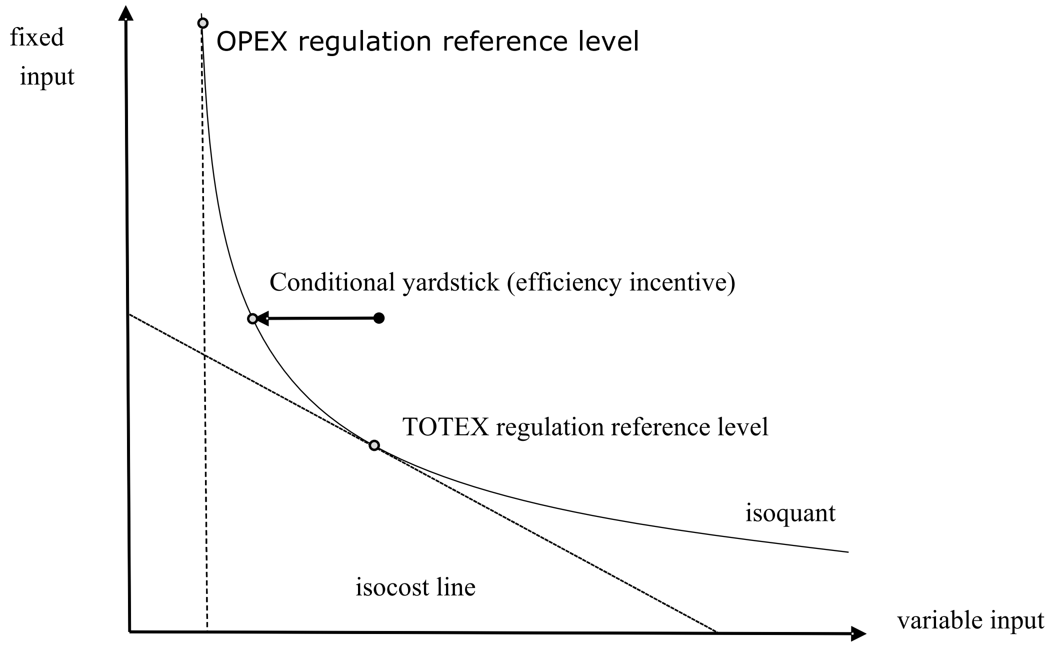

***Figure 2:** Conditional yardstick competition (reference: Kuosmanen & Johnson (2020))*

Figure 2 illustrates the economic theoretical framework of the conditional yardstick competition. Only regulation based on variable costs would involve companies to aim to minimise their operational costs and the reference level minimising costs is presented at the upper point of the vertical line. However, a point minimising variable costs would require the company to make very significant investments in network capital and this would lead to over-investments that would not be economically sound. Similarly, the reference level according to the regulation based on total costs is presented in the graph as a point where the isocost line and the isoquant that describes the technical substitutability of the inputs run parallel to each other. The point represents a fixed and variable input utilisation rate that minimises total costs. However, as mentioned above, it is very difficult to adjust the capital stock towards an optimal level in the short term.

The basic idea of the conditional yardstick competition is to standardise the network capital describing the fixed input in the short term, but nevertheless take it into account in the assessment of the reasonable operational cost level. The reference level of the conditional yardstick competition in Figure 2 is the isoquant point to which the arrow points in the figure. In practice, the distance of the arrow describes the network company’s efficiency potential and efficiency incentive, i.e. the starting point is the network company's current cost level and the end point on the isoquant is the reference level for efficient operation. Therefore, the purpose of the efficiency incentive is to guide the network company in the short term towards the efficient cost frontier described by the isoquant.

In the long term, the fixed input, i.e. network capital, should be adjusted towards a point that minimises total costs. As the conditional yardstick competition does not require the adjustment of capital, it is possible to achieve an efficient reference level for variable, i.e. operational costs, in the short term. Therefore, conditional yardstick competition does not encourage network companies to replace variable costs with fixed capital (over-investment) or penalise the companies for their previous investment decisions if the criteria for this are not met. As the model takes into account the level of operational costs as conditional in terms of the amount of network capital, the model can also be considered to treat the use of different operational solutions in network operations neutrally. Therefore, the model does not restrict, for example, the use or development of various flexibility methods that prove to be economically efficient.

As pointed out above, the Energy Authority has since 2016 been applying the conditional yardstick competition illustrated above, in which the regulation is concerned with operational costs, while also taking into account the network company's network capital, i.e. fixed costs. The model introduced at the beginning of the fourth regulatory period is based on a 2014 report[26] commissioned by the Energy Authority from Sigma-Hat Economics Oy.

3.2.2 Proposed change to the efficiency incentive for the 6th and 7th regulatory periods

As a part of the development of regulation methods for the sixth and seventh regulatory periods, the Energy Authority commissioned a report from ECKTA Oy[27] on the efficiency measurement of electricity distribution network operations, which assessed the currently applied method, model specification, and input and output variables. The report considered that the model currently applied by the Energy Authority based on a conditional yardstick competition is still a recommended option for determining the reference level of the controllable operational costs, and the report did not propose fundamental changes to the model. However, the study recommended that certain changes be made to the applied method and the parameters used in the model, mainly from the perspective of the model's anticipation

[26] Sigma-Hat Economics Oy / Kuosmanen, T., Saastamoinen, A., Keshvari, A., Johnson, A., Parmeter, C., Tehostamiskannustin sähkön jakeluverkkoyhtiöiden mallissa (The efficiency incentive in the regulatory model for electricity distribution network companies), 2014

[27] ECKTA Oy / Kuosmanen, T., Kuosmanen, N., Dai, S., Kohtuullinen muuttuva kustannus sähkön jakeluverkkoyhtiöiden valvontamallissa: Ehdotus tehostamiskannustimen kehittämiseksi 6. ja 7. valvontajaksoilla vuosina 2024–2031 (Reasonable variable cost in the regulatory model for electricity distribution system companies: A proposal for the development of an incentive for the 6th and 7th regulatory period in 2024–2031), 12 September 2022

capacity and incentive impacts. Development proposals for the efficiency incentive put forward by the Energy Authority for the sixth and seventh regulatory periods:

Development of the StoNED method:

- Restricting the distribution of shadow prices

Model variables:

- Replacing the replacement value of the network (RCV) with the net present value (NPV)
- Considering the loss electricity percentage as a control variable

General efficiency target:

- General efficiency target of 0% in the sixth regulatory period and 1% in the seventh regulatory period

Calculation of the reference level:

- Calculating the company-specific reference level takes into account the NPV for each year and the realised DCO value

The amendments proposed by the Energy Authority and the related justifications are discussed below.

3.2.2.1 Limiting the range of shadow prices

The shadow prices of outputs and inputs obtained in cost frontier estimation are interpreted as marginal costs from the perspective of economics. In the context of the efficiency measurement method applied by the Energy Authority, marginal costs describe the impact of adding an output or input unit on operational costs. Shadow prices, i.e. marginal costs, are estimated for each output and fixed input based on the observation data used. Meanwhile, the shadow prices serve as coefficients for realised company-specific output and input observations when calculating a reasonable cost level in accordance with the shadow price profile. In monopoly operations, in the absence of actual markets, shadow prices in the cost frontier model can be interpreted as virtual markets within which companies compete in cost-effectiveness in comparison with other companies.

In the method currently applied by the Energy Authority, setting shadow prices has been implemented so that when calculating a reasonable cost level for each company, a shadow price profile that maximises the cost level is selected and the company's operations appear in the most competitive light. In other words, the method of selecting shadow price profiles also maximises the efficiency of the sector as a whole. Shadow prices that differ from one another take into account DSOs' different output structures and the different shadow price profiles put different emphases on the outputs as cost factors. Indeed, there may be considerable company-specific and annual fluctuations in shadow prices for this reason.

The report by ECKTA Oy proposes that the same logic be used to determine the shadow price profiles for each company, i.e. out of all shadow price profiles, a shadow price profile that maximises the reference level for operational costs is selected for the company. However, the report recommends limiting the shadow prices obtained through frontier estimation, which means in practice that the extreme values of the distribution of shadow prices are excluded in the calculation of the reference level for costs.

Limiting the range of shadow prices is justified from the perspective of improving the model's predictive capacity and from the perspective of so-called overfitting. The output profile of the network companies can be considered to have changed over the past few years, which manifests as occasionally significant annual variations in the amount of transferred energy, for instance. Changes coming from within and outside the sector may increasingly affect electricity consumption in the future and therefore also the amount of transferred electrical energy, which means that the cost frontier model used to model reasonable costs should also be able to predict the cost level more effectively also beyond the used observation data.

On the other hand, limiting shadow prices is also justified when the aim is to prevent overfitting. In research literature, overfitting is referred to occur in a phenomenon where the model succeeds "too well" in explaining the used data. In the problem of overfitting, the model has good explanatory capacity within the framework of the used observation data and minimises empirical risk, but it may not be able to consider observations outside the used observation data. In other words, the model cannot model new data, which means that it has a poor predictive capacity. Overfitting is a relevant problem for the cost frontier model, firstly because the model is complex, including a large number of estimated parameters, which are bound by the theoretical constraints on the form of the cost frontier. Secondly, the efficiency measurement practice applied by the Energy Authority is based on an ex-ante practice, which means that the reference level for costs applied to future years is determined on the basis of observation data from past years. Therefore, in practice, the applied cost fronter model is estimated based on observation data from previous regulatory periods, but the estimated parameter values are applied to determine a reasonable variable cost level for the future regulatory period. For this reason, the report by ECKTA Oy particularly examined proposals for changes to improve the model's predictability.

The report included testing imposing limits to shadow prices using different practices and assessing the impacts of each option on the model's predictability. The impact of limiting shadow prices on the model's predictive capacity has been tested by dividing the company-specific observation data provided by the Energy Authority covering the period 2008–2020 into a so-called training set (2008–2016) and a test set (2017–2020). The parameters of the cost frontier model have first been estimated for the training set after which the parameters have been applied to the test set. This makes it possible to describe the model's predictive capacity, which in turn can be measured using the root mean squared error (RMSE). The tested alternative model specifications were ultimately compared to the model applied by the Energy Authority during the fourth and fifth regulatory periods.

In the comparison, the best prediction capacity was produced by a method recommended in the report in which the shadow prices of each output and input variable are limited separately. This allows still taking into account the scale of each variable as well as their range. Based on the report, it is recommended to limit the top and bottom decile in the distribution of shadow prices for each output and input variable (i.e. the lowest 10% and highest 10%).

As the cost frontier is estimated based on the output and input data of all electricity distribution network companies, freely determined unrestricted shadow prices can lead to unrealistically high marginal costs and particularly overestimate the cost level of network companies with atypical input/output profiles. An atypical profile refers to network companies that do not necessarily have reference companies with a similar output profile. Although marginal costs naturally differ between companies, there are justifications for limiting the marginal costs range to ensure that these do not become unreasonably high. However, the principle of the intensification incentive is to set companies' controllable operational costs at a level that can be deemed reasonable.

3.2.2.2 Replacing the replacement value of the network (RCV) with the net present value (NPV)

There is always a certain ratio of substitution between operational costs and capital investments; in electricity distribution network operations, investments in network capital can be used to avoid operational costs, while operational measures can be used to postpone an investment decision. Due to this ratio of substitution, the impact of the fixed input variable in the conditional yardstick competition model applied by the Energy Authority always reduces the reference level of controllable operational costs. In practice, if the value of the company's network capital is low in relation to the output level, this can be used as a justification for the company's higher operational costs and vice versa. Therefore, the model takes into account the use of different operational solutions in network operations in a neutral way and does not limit the use of different flexibility methods in network operations, for instance.

In the model applied during the fourth and fifth regulatory periods, the fixed input of the conditional yardstick competition, i.e. network capital, was modelled using the replacement value of the network of the electricity distribution network companies. However, the report of ECKTA Oy recommends replacing the replacement value of the network (RCV) that describes the fixed input with the net present value (NPV).

As the net present value of the network is calculated on the basis of the replacement value of the network but takes into account the imputed straight-line depreciation of the network capital, the net present value can be considered to better reflect the value of the network's capital stock in that year. Replacing the replacement value with the net present value is also justified because the net present value takes into account replacement investments in the network, which in turn do not affect the replacement value of the electricity network. Replacement investments can contribute to reducing operational costs, which is why there are justifications for also taking them into consideration in determining the reference level for operational costs. Taking NPV into account as a variable describing the fixed input can be considered to encourage network companies to make economically advantageous investments.

The report also included an examination of substituting the network replacement value with the net present value from the perspective of the predictive capacity of the cost frontier model. The report focused on the comparison of the current model and the weight-restricted model presented in the previous section. The comparison of the model's predictive capacity between the net present value and the replacement value was carried out by dividing the observation data into a training set and test set, and by measuring the accuracy of the predictions using mean square deviation. Based on the results of the study, the use of the net present value as a fixed input improves the predictive accuracy of the model both in the training set and test set. Indeed, the best predictive accuracy can be obtained by using a weight-restricted model that models the network's net present value as a fixed input. Therefore, substituting the replacement value of the network with the net present value as a variable describing the fixed input is also justified in terms of the predictive capacity of the model.

In the calculation of the reference level, the replacement value of the distribution network was fixed at the average level of the period 2011–2014 in the fourth regulatory period and at the average level of the period 2015–2018 in the fifth regulatory period. Averaging was used to reduce the impact of the variation in the network value variable on the determination of reasonable, controllable operational costs. In the sixth and seventh regulatory periods, however, the averaging practice will be abandoned so that changes in the capital stock will also be taken into account in the calculation of the reasonable annual operational costs. This means that the net present value of the given year will be always used in the calculation of the reference level for costs in that year.

In the estimation of the cost frontier for the efficiency incentive, the current net value of the network modelled as a fixed input variable will be defined and harmonised for the period 2016–2023 using the unit price list in Appendix 1. In other words, for the efficiency incentive, a parallel calculation of the net present value is applied for the years covered by the data used in the estimations, in the calculation of which the applied baseline is the net present values determined for 2023. On this basis, the net present values for 2016–2022 are calculated retrospectively. This procedure is used to ensure the most consistent development and comparability of the value of the network from the perspective of the efficiency incentive in the data periods applied in the cost frontier during the sixth and seventh regulatory periods.

The calculation of the net present value is based on the calculation method used in the second regulatory period, in which case the net present value of the preceding year is always based on the net present value of the examined year minus the investments of the year under review and plus the straight-line depreciations of the year under review. The calculation method may also be presented using the below formula:

$$NPV_{y-1} = NPV_{y,UPAppendix1} - inv_{y,UPL2016} + SD_{y,UPL2016}$$

where

$NPV_{y,UPAppendix1}$ = the net present value of year y in accordance with the unit price list provided in Appendix 1

NPV_{y-1} = net present value of year t-1 for estimation

$inv_{y,UPL2016}$ = investments of year t in accordance with the 2016 unit price list

$SD_{y,UPL2016}$ = straight-line depreciations of year t in accordance with the 2016 unit price list

When calculating the net present values as described above, the network values can be harmonised throughout the dataset period, and in this case, the net present values used to calculate the annual reference level values during the regulatory period are based on the network values calculated according to the same unit price list. In this case, from the perspective of the efficiency incentive, the network value will not be subject to variation in network value during the data period due to updates to the unit prices, and the net present value will develop more evenly from the perspective of the model. The calculation will utilise the data from the previous regulatory period in investigating investments and straight-line depreciations, which have been calculated using an older component breakdown, because it would be too challenging to retrospectively determine the investment data and straight-line depreciation for the older years included in the data period with a newer component breakdown until 2016.

For the purposes of the calculation, DSOs are required to submit to the Authority, by June 2024, the quantity and average age data of the network components in actual use as well as the required lifetime data based on the new breakdown in accordance with Appendix 1 depicting the status valid at the end of 2023. The Authority will issue instructions for providing the necessary information during spring 2024.

During the seventh regulatory period, regulation data obtained in the period 2020–2026 will be used as the data for estimating the cost frontier. For the applicable net present values, the period 2020–2023 will be based on the net present values determined as described above; in the period 2024–2026, network value data will be directly obtained from network value calculations in accordance with the network data system.

3.2.2.3 Adding loss electricity percentage as a control variable

ECKTA Oy’s report also recommended that the annual loss electricity percentages of the distribution network companies be added to the model as a control variable, which can be considered to be linked to the technical performance of the distribution network as a variable.

Using the loss electricity percentage in the model as a control variable is justified because it mitigates the so-called endogeneity bias. In econometrics, an endogenous variable refers to an explanatory variable in the model that correlates with an error term. Endogeneity bias is corrected by applying a control variable that can be used to refine estimates and to further distinguish the effect of explanatory variables from the error term. In the context of the cost frontier model applied to electricity distribution network companies, endogeneity is mainly due to the fact that the model's error term may be correlated with input and output variables taken into account as explanatory variables or factors describing the operating environment. If the explanatory variable is positively correlated with the error term, the model may overestimate the effect of that variable in the model by also binding the indirect effect of the inefficiency term with it. Therefore, the model may overcompensate the cost effects of an explanatory variable that positively correlated with the error term. To mitigate the endogeneity bias, a control variable is used, which strongly correlates with the model's inefficiency term.

In the report of ECKTA Oy, the loss electricity percentage is found to correlate positively with the current model's regression residuals, in which case there is a statistical link between the estimated inefficiency and the loss electricity percentage. The report also found a negative correlation between the annual loss electricity percentages and the net present value/replacement value ratio that describes network capital, which indicates that the share of loss electricity is higher in a network older in terms of its lifetime compared to a newer network. The report also found that the loss electricity percentage correlates positively with the connections/metering point ratio that describes the operating environment variable, which in turn indicates that there is a relatively higher number of losses in sparsely populated areas than in urban networks.

The inclusion of the loss electricity percentage as a control variable in the model is considered to reduce the endogeneity bias and the criteria for including it in the estimation phase of the model are therefore met. However, the report does not recommend using the loss electricity percentage as a variable describing the operating environment, mainly due to its incentive effects. As there is a positive statistical link between loss electricity and controllable operational costs, the inclusion of loss electricity percentage in the model would appear to increase costs, which, in turn, would create an incentive to increase losses in the distribution network. Therefore, the loss electricity percentage is modelled as a control variable in the estimation phase, but its effect is restored in the model residuals before the estimation of the inefficiency term.

3.2.2.4 General efficiency target

In practice, the annual company-specific efficiency target or efficiency figure reflects the company's static efficiency, i.e. its short-term performance in relation to a specified reference level, and provides a situational picture of the company's direction towards a long-term efficiency balance. As a result, the efficiency incentive often also includes a general efficiency target, i.e. a dynamic component used to take into account the efficiency potential created by technological developments. In economic terms, a change in production technology describes a shift in the curve of production opportunities, which means that the same amount of input can be used to produce a higher amount of output, or, otherwise put, it should be possible to produce the same output amount with a lower input use. In other words, the general efficiency target aims to guide companies to also develop their cost-effectiveness over time. In the efficiency incentive, the general efficiency target is taken into account annually in the calculation of the reference level.

During the second and third regulatory periods, an annual general efficiency target of 2.06% was applied similarly to electricity distribution network operations. The definition of the general efficiency target describing productivity development was based on a report commissioned by the Energy Authority from Gaia Consulting Oy[28], in which the technical development in the sector was described using the Malmquist productivity index. The Authority also commissioned a report from Sigma-Hat Economics Oy[29] on the application of the general efficiency target for the fourth and fifth regulatory periods. The report recommended that an efficiency target of 2% should be similarly applied based on technological development in the fourth and fifth regulatory period. However, the Energy Authority ultimately decided to set the overall efficiency target at 0% for electricity distribution network operations in the period 2016–2023. The decision was made in order to take into account the new tasks of DSOs resulting from the general efficiency target through both national and European legislative changes. Based on the Authority's view, the clearest and sufficiently valid solution involves taking into account these costs resulting from new tasks and operating methods as well as the benefits in the calculation of realised adjusted profit by adjusting the level of the general efficiency target.

[28] Gaia Consulting Oy, Syrjänen, M., Lausunto tuottavuuskehityksen huomioivasta alan yleisestä tehostamistavoitteesta (Statement on the general target of improving the efficiency in the sector taking the development of productivity into consideration), 9 February 2007

[29] Sigma-Hat Economics Oy / Kuosmanen, T., Saastamoinen, A., Yleinen tehostamistavoite sähkön ja maakaasun siirto- ja jakeluverkkotoiminnan valvontamalleissa sekä tehostamiskannustimen arviointi: Ehdotus Energiaviraston soveltamien menetelmien kehittämiseksi seuraavilla valvontajaksoilla (General efficiency target in the regulatory models for electricity and natural gas transmission and distribution network operations and an assessment of the efficiency incentive: a proposal for the development of methods applied by the Energy Authority in the next regulatory periods).

For the coming sixth and seventh regulatory periods, the Energy Authority commissioned a report from ECKTA Oy on the application of the general efficiency target[30]. The report recommends the uniform application of the 2% general efficiency target in all electricity network sectors. With regard to electricity distribution network operations, the level of the general efficiency target has been justified as an opportunity for companies found to be efficient in efficiency measurements to improve their cost-efficiency over time. ECKTA Oy's report examined the average annual change in the cost-effectiveness of electricity distribution network companies identified as the most efficient in efficiency measurements. According to the report, the most efficient percentage of companies was able to improve their cost-effectiveness by an average of 3.6% per year in the period 2012–2020 examined in the report. However, the report recommends that the general efficiency target be made more reasonable and that the same 2% level be applied in all electricity network sectors.

In accordance with the report by ECKTA Oy, the Energy Authority proposed in the draft guidelines on regulatory methods that the 2% annual level of the general efficiency target should be applied during the sixth and seventh regulatory periods. Nevertheless, the opinions on the draft guideline highlighted that the energy transition would highlight the electricity system, while calling for additional planning, for example through different demand response solutions, growth in small-scale production and energy reserves. Meanwhile, the new operating methods and services mean an increase in operational costs.

With regard to future regulatory periods, the Energy Authority considers it important that the regulation methods will enable more economically cost-neutral development of network operations also in terms of the benefits of the end user. This objective is closely linked to the development of various flexibility services, which means that certain solutions can be used to, for example, avoid or significantly postpone expensive network investments in areas where investments are not profitable in terms of costs and benefits.

In order to maintain the possibility for distribution network companies to develop solutions focused on operational costs, the Energy Authority proposes, by way of derogation from the first draft guideline, a general efficiency target of 0% to be applied during the sixth regulatory period and an annual efficiency target of 1% to be applied during the seventh regulatory period.

The Authority also proposes that, in the seventh regulatory period, the costs of flexibility solutions procured on market terms will be treated as a pass-through item

30 ECKTA Oy / Kuosmanen, T. , Yleinen tehostamistavoite sähkön ja maakaasun verkkotoiminnoissa 6. ja 7. valvontajaksoilla (General efficiency target for electricity and natural gas network operations in the 6th and 7th regulatory periods), 15 November 2022

and they will thus not be included as costs included in the efficiency incentive. In the sixth regulatory period, the costs related to flexibility are included in the controllable operational costs but are subject to a separate bonus mechanism through the flexibility incentive. This provides distribution network companies with an incentive to develop the yet undeveloped flexibility market into an integral part of the electricity distribution network operations. The costs related to flexibility are presented in more detail in the section on the flexibility incentive (4.5).

The Energy Authority considers that this ensures sufficiently taking into account the cost pressure arising from the increasingly complex operating environment and new operating methods and requirements in terms of operational costs. However, the Energy Authority considers it appropriate to include a moderate general efficiency target of 1% in the seventh regulatory period. Taking into account the quality requirements laid down in the Electricity Market Act and the investments made in the electricity distribution network to meet these over the past ten years, the maintenance and service costs of the network will also inevitably decrease as the security of supply of the network improves. Therefore, the structure of operational costs can be considered to change to some extent, but the long-term cost level is not expected to change substantially.

3.2.3 Preliminary cost frontier for the period 2024–2027

In September 2023, the Energy Authority estimated a preliminary cost frontier using the monitoring data provided by distribution network companies covering the period 2016 –2022. The shadow prices according to the cost frontier and the calculation workbook for the reference level of the efficiency incentive were published in connection with draft confirmation decisions and the regulation method appendix. Distribution network companies are requested to check the company-specific information presented in the calculation workbook. Changes in the data set will be taken into account in the final efficiency frontier applied in the period 2024-2027, which will be estimated and published by the end of 2024 at the latest.

The calculation workbook presents the shadow prices and parameters estimated according to the updated model using the data from the period 2016–2022. The calculation workbook also presents annual efficiency figures calculated for each company for each year of data. In other words, for each company, the annual efficiency figures describe the relationship between input-output combinations in the past years and the updated cost frontier.

A comparison of the efficiency figures in accordance with the updated cost frontier with the cost frontier based on the data used in the fifth regulatory period (2012–2018) shows that the efficiency figures for both data periods differ from each other.

As the technology described in the updated cost frontier is more cost-effective than before, the efficiency figures in the updated cost frontier are given lower numerical values compared to the old cost frontier. In practice, technological progress moves the efficiency frontier in time (the isoquant moves in the examination of production potential), where the same input-output combination is located further away from the efficient frontier. The difference between dynamic and static efficiency is illustrated in this examination.

However, instead of looking at the historical evolution of efficiency figures, it is more relevant to examine the shadow prices in line with the cost frontier, which will be applied during the upcoming regulatory period. Table 2 shows the development of shadow prices for the data used during the fifth regulatory period and the preliminary cost frontier applied during the sixth regulatory period. Both estimates are based on the weight-restricted CNLS model presented by ECKTA Oy (WR CNLS (10%, 90%)), in which the net present value of the network is used as the fixed input variable and the loss electricity percentage is used as the control variable. The Energy Authority published the results of the estimation carried out using the data from the period 2012–2018 on its website in late 2022. The table shows the shadow price median, maximum and minimum values of the outputs (transferred energy, network length and number of users), undesirable output (DCO) and the fixed input variable (NPV) for each estimation window.

WR CNLS (10%,90%) 2016–2022	**Energy (s/kWh)**	**Network length (€/km)**	**Number of users (€/user)**	**NPV (€/€1000)**	**DCO (€/€)**
Median	1.390	126.07	55.39	2.122	0.028
Maximum	3.331	271.00	81.00	28.399	0.168
Minimum	0.007	0.00	2.00	0.00	-3.295
WR CNLS (10%,90%) 2012–2018					
Median	1.375	163.74	44.49	2.349	-0.089
Maximum	5.049	334.99	89.99	36.261	0.106
Minimum	0.004	0.00	18.00	0.00	-3.557

***Table 2**: Median, maximum and minimum of outputs and fixed input shadow prices in the period 2016–2022 and 2012–2018*

The shadow prices of cost frontier estimations conducted in different data periods reveal that the median values of the shadow prices of the number of users and transferred energy increase with the updated data compared to the 2012–2018 data. The median shadow prices of NPV which describes the capital stock, and DCO, which describes outage costs, also increase. Meanwhile, the median shadow price for the network length decreases.

The changes in shadow prices and their relationships are natural, taking into account the different data periods used in the estimations. In the rolling estimation procedure applied in efficiency measurement, the oldest periods are always removed in connection with the frontier update, at which point the model practically forgets any input-output combinations of previous years. Meanwhile, the development of the input-output combinations observed in the data affects the estimated shadow prices and therefore also the form and location of the cost frontier.

However, the shadow prices presented in Table 2 are not fully comparable, as the preliminary estimation for the sixth regulatory period takes into account the updated unit prices of outages (DCO value) in accordance with the report commissioned by the Authority from AFRY Management Consulting Oy, whereas the DCO values used in the estimation of the data for the fifth regulatory period are based on the unit prices of outages applied during the fourth and fifth regulatory periods. Nevertheless, based on test calculations carried out by the Authority, the updated DCO values do not appear to have a significant impact on the formation of shadow prices.

It has been proposed that, in the sixth and seventh regulatory periods, demolition costs of replacement investments in network assets capitalised on the balance sheet should be considered as part of the controllable operational costs for the year in question and they would therefore also be included in the efficiency incentive. To ensure that the demolition costs would also be taken into account in the determination of the reference level of the efficiency incentive in the sixth regulatory period, data will be collected from the network companies on the activated demolition costs for 2016–2023 by means of a separate request for information in early 2024, and the corresponding costs will be added to the actual operative costs used in calculating the reference level.

It has also been suggested that the network data systems and the costs of the communication networks in the supervisory control and data acquisition should be included in the controllable operational costs by treating the costs as pass-through items in the sixth regulatory period and including them in the controllable operational costs under the efficiency incentive in the seventh regulatory period. To ensure that the costs will also be taken into account in the calculation of the reference level during the seventh regulatory period, data will be collected from the network companies on similar costs for the period 2020–2023.

While the above costs have not been taken into account in the estimation of the preliminary cost frontier, the costs will be included in the frontier estimates for the sixth and seventh regulatory periods as proposed, and therefore the costs will also be taken into account in the reference level of the incentive.

In addition, the final frontier estimation applied during the sixth regulatory period will take into account the net present value of the modelled network as a fixed input variable based on a uniform definition, as described in section 3.2.2.2.

These changes will contribute to the estimated shadow prices, but on the other hand, the changes will ensure the equal treatment of costs and comparable development of network value from the perspective of the efficiency incentive in future regulatory periods. As noted, the Energy Authority will estimate the final efficiency front applied during the sixth regulatory period once all the necessary baseline data have been checked and the aforementioned cost data have been collected from the companies, however no later than by the end of 2024. In a few of the opinions, it was pointed out that the estimation of the efficiency frontier after the start of the regulatory period does not meet the criteria for the good principles of ex-ante regulation. Nevertheless, data on items included in the controllable operational costs must be collected from the companies to ensure that these also get taken into account in the calculation of the reference level for the incentive. The Energy Authority would also like to point out that the final cost frontier applied during the fourth regulatory period was published in September 2016, i.e. already after the regulatory methods entered into force, i.e. the proposed practice does not differ from the previously used one. The authority has also published a preliminary cost frontier estimation for the sixth regulation period, which is indicative and allows companies to assess to a certain extent the reference level of the efficiency incentive for the coming regulatory period even before the entry into force of the regulation methods.

3.2.4 Equal treatment of electricity distribution network companies

In their opinions, a few distribution network companies have expressed a view at the different consultation phases of method development that the StoNED model treats different distribution network companies unfairly, referring to the results of the analysis[31] commissioned from Gaia Consulting Oy in spring 2023. According to the analysis, especially companies with electricity networks located in both urban and rural conditions (so-called mixed network companies) are put in a disadvantaged standing by the StoNED model compared to exclusively urban or rural network companies. In the Gaia analysis, electricity distribution network companies were divided into seven clusters according to the size of the company (net present

[31] The analysis was published on the Energy Authority's website as part of the opinions received for the first guidelines of the regulation methods.

value) and the operating environment variable (C/M ratio), and the efficiency figures of the formed clusters were finally compared. The analysis concludes that the StoNED model rewards the economy of scale and specialisation.

The equal treatment by the StoNED model specifically related to the so-called mixed networks has also been a topic of discussion in connection with the previous regulation methods and earlier regulatory periods. The StoNED model has been applied as an efficiency measurement method since 2012, and the problem addressed in the opinions has not been identified in the statements of the working groups carrying out studies on the efficiency measurements or by the Energy Authority. However, the Energy Authority considers it appropriate to again comment on the matter in this context.

As a part of the opinions, the analysis submitted to the Energy Authority presents the distribution of efficiency figures by company category, and according to this comparison, "small mixed networks and urban networks" receive the lowest average efficiency figure. However, the analysis does not directly reveal the reasons behind selecting the used seven clusters or how similar the distribution network companies included in the individual clusters are to one another. An examination of Graph 1 of the analysis allows observing visually that the number of observation points for enterprise clusters drawn in the graph does not correspond to the number of network companies included in the clusters indicated in the graph. As no background material for the analysis was submitted in connection with the opinions or the analysis, it is difficult to assess whether there is an error in the graph or whether company categories that differ from the clusters have been taken into account in the examination of the efficiency figures of the company categories. Naturally, the companies selected for the clusters determine what the distribution of efficiency figures between the clusters looks like. The analysis also does not indicate on what basis the cost frontier has been presented or whether the average efficiency figures presented are based on observations made for a single year.

Firstly, with just a few exceptions, almost all distribution network companies can be interpreted as mixed networks, i.e. their operating area includes both urban and rural electricity distribution areas. However, this has not restricted the possibilities of distribution network companies operating in different operating environments to achieve a level of costs indicating efficient operations in accordance with the cost frontier, and consistent efficiency improvements that have taken place over time can be observed for several companies. It should also be noted that the model itself takes into account the heterogeneous nature of distribution network companies also through the shadow prices of estimated outputs, not only through a variable describing the operating environment.

Efficiency figures naturally vary, even for individual distribution network companies, on a year-by-year basis, depending on the actual output-input amount of the year under review in relation to the reference level used for the cost frontier. As a result, it makes sense to examine the distribution of efficiency figures on the basis of a period longer than a single year.

When examining the distribution of efficiency figures of all the distribution network companies in relation to the model's operating environment variable (C/M ratio) like in Figure 3 in accordance with the preliminary estimation published by the Energy Authority for the sixth regulatory period (using data from 2016 to 2022), the distribution of efficiency figures shows nothing exceptional or an impact that would emphasise the efficiency of extremes (urban or rural network). Above all, the graph emphasises that event the efficiency figures of an individual company may vary during the data period and that no company's performance in relation to the reference level is in any way locked in relation to its operating environment. Almost without exception, moving on the axis describing the C/M ratio shows that there are both effective and ineffective observation points.

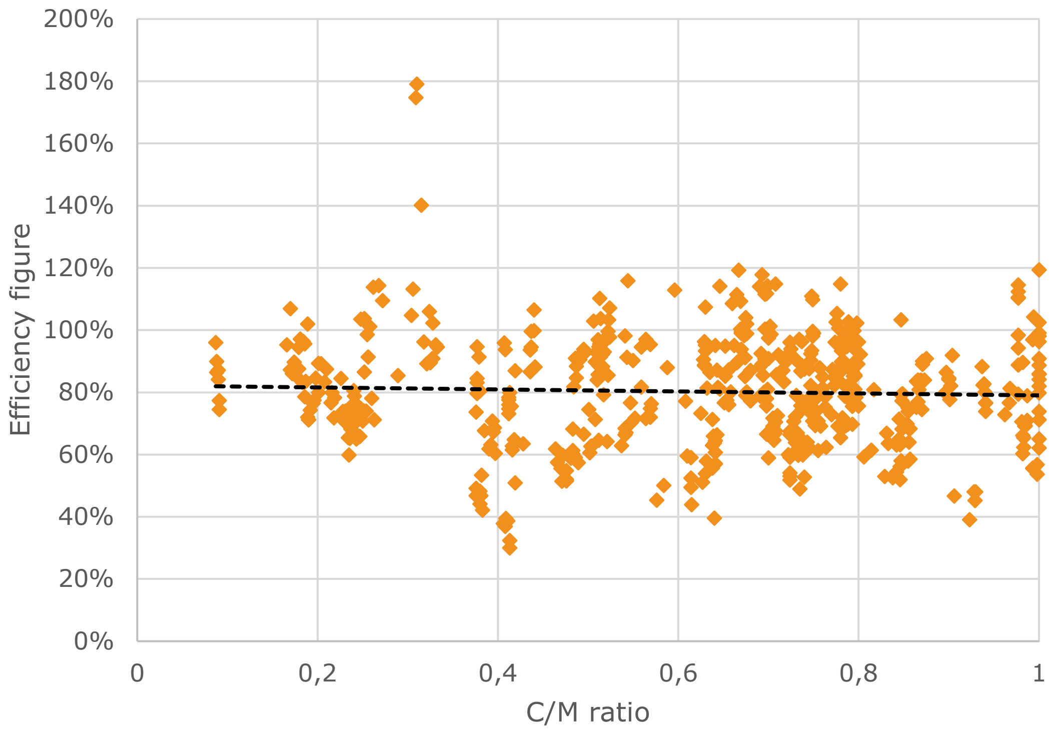

*Figure **3**: Distribution of efficiency figures from the period 2016–2022 in relation to the operating environment variable*

Meanwhile, an examination of the division of efficiency figures per company groups divided into distribution network companies in urban areas, built-up areas and sparsely-populated areas as illustrated by Figure 4 shows that the efficiency figures from the period 2016–2022 are divided somewhat similarly between different company groups. It is also noteworthy that the average of the efficiency figures of the companies operating in built-up areas (which are considered to operate in both urban and rural environments) is given the highest value in the examined dataset.

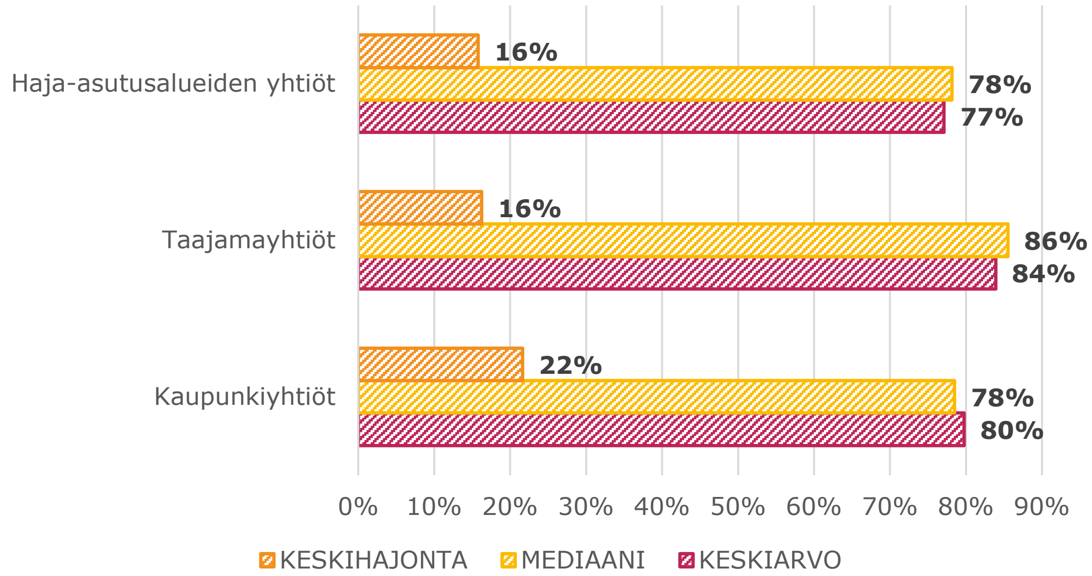

Figure 4: *Average, median and standard deviation of efficiency figures by company category*

As presented above, no element causing inequality can be observed in the application of the StoNED model between different companies. Instead, the model takes into account the input-output structure and operating environment of network companies equally regardless of the size of the company.

3.2.5 Efficiency incentive for high-voltage electricity distribution network operations

The incentives for the regulation methods of high-voltage electricity distribution network operations also include an element that examines operational efficiency, whose purpose is to guide network companies to operate in a cost-effective manner. Network operations can be considered efficient when the inputs used in the operations are as low as possible in relation to the outputs obtained. The efficiency incentive is based on the DSO’s variable costs, i.e. controllable operational costs.

In the fourth and fifth regulatory periods, the controllable operational costs of the efficiency incentive applied to high-voltage electricity distribution network activities are compared with the reference level calculated on the basis of historical costs. In the first year of the regulatory period, the reference level of the efficiency incentive will be determined as the average of the DSO's realised controllable operational costs of the previous regulatory period, i.e. the previous four years. In the following years of the regulatory period, the reference level defined for the previous year, i.e. reasonable, controllable operational costs, will be used as the reference level for the incentive. In calculating the reference level, the impact of inflation and the so-called network volume is taken into account.

The network volume is used to take into account changes in the scope of the DSO's operations, and it is calculated using the DSO's overhead line network, underground cable network and the number of customers and the corresponding cost coefficients. In other words, the regulation model applies the change in the network volume as an output index, and the model allows the DSO to increase its costs at most in line with the increase in the output measured based on the network volume.

As part of the development of regulation methods for the sixth and seventh regulatory periods, the Energy Authority commissioned a report from ECKTA Oy[32] to assess the current efficiency incentive practice. According to the report and the internal assessment of the Energy Authority, it is not necessary to change the current form of the efficiency incentive for high-voltage electricity distribution network operations for parts other than in relation to the level applied in the general efficiency target.

By way of derogation from the first draft guideline, the Energy Authority proposes that the general efficiency target of 0% be applied in the sixth regulatory period and an annual efficiency target of 1% be applied in the seventh regulatory period similarly as in the electricity distribution network operations. The definition of the general efficiency target has already been discussed in section 3.2.2.4. of this memorandum.

3.3 Investment incentive

The same principles as before apply to the investment incentive. The adjusted frozen replacement value of the network component is divided by the network component lifetime. As the aim is to only take inflation into account once through the nominal rate of return, the calculation will be based on frozen unit prices describing average acquisition costs.

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[32] ECKTA Oy / Kuosmanen, T. , Yleinen tehostamistavoite sähkön ja maakaasun verkkotoiminnoissa 6. ja 7. valvontajaksoilla 2024–2031 (General efficiency target for electricity and natural gas network operations in the 6th and 7th regulatory periods 2024–2031), 15 November 2022

The incentive impact continues to arise from the difference between investments calculated with unit prices and the cost of realised investments. When investing cost-effectively on average, the DSO reaps benefits from the adjustment of network assets; similarly, when a DSO invests ineffectively, unit prices cut off overheads in the adjustment of network assets. The benefit of the incentive is therefore reflected in the adjusted net present value and the adjusted depreciation level of the straight-line depreciation.

The benefits brought by this practice have been historically considerable on average, particularly in the case of individual companies. The agency has found it problematic that the benefits may not be transferred to customers. For this reason, the Energy Authority has estimated that any benefits arising from unit prices should be made more reasonable in the future and to otherwise ensure that customers will also benefit from efficient years in the future. As a result, the Energy Authority has decided that in the future, a benefit cutting system will be applied in the investment incentive in relation to straight-line depreciation.

3.3.1 Criteria for introducing the benefit cutting system

For customers, the benefits of the investment incentive have only been visible in the regulatory period when DSOs have made investments on average at prices higher than the unit prices or in updating the unit prises if the costs have decreased on average. Of course, customers have also benefited from an increase in unit prices if it is assumed that the increase in unit prices has not been as great at this point as it might have been without the incentive impact of unit prices.

However, the situation may be such for customers that the unit costs have on average increased or remained the same just before they were updated, which means that even in connection with the update, the benefit brought by the unit prices previously during the regulatory period will only be of use to the DSOs. The previously used principle enables a situation where more expensive investments are emphasised at the end of the period at the time when unit prices are updated. This means that, despite an average improvement in efficiency, the updates to unit prices may not be reflected as an actual decrease in unit prices to the same extent as on average during the regulatory period. It is also otherwise possible to end up in a situation within the period in which the costs are lower than the unit prices at the beginning of the period and higher than the unit prices at the end of the period.

Referring to the above, the benefit cutting system is used to ensure that, despite the evolution of costs, the efficiency previously achieved will also partly benefit customers, especially in the current situation where the adjustment principle required by the nominal rate of return is used, in which updating the new unit prices does not affect the adjustment of the old mass as a whole.

Another key criterion for the benefit cutting system is that it seeks to guide more accurate capitalisation in the DSO's accounting and to prevent unjustified additional returns. The Energy Authority has noted that DSOs have deficiencies in carrying out accurate capitalisation of investments that would reflect the actual time of implementation. In other words, some DSOs retain parts of investments that have already been completed and introduced for too long in their incomplete investments. In such cases, the DSO has already reported the data on the introduced components in the structure data and the investment has been adjusted with unit prices, and has therefore obtained reasonable return and depreciation for them. At the same time, the DSO may still keep the cost item in question in unfinished investments in its accounting and may receive a reasonable return for this through the methodologies. This practice enables the DSO to obtain undue benefit from the methodology.

Utilising the benefit cutting system in the investment incentive guides the DSO to operate correctly, as including this dragging cost item in acquisitions in progress may make the DSO appear more efficient than it actually is, in which case the benefit cutting system may cut some of the depreciation accumulated to the component. For example, for a company that operates precisely in accordance with unit prices, but whose accounting lags too far behind at the time of implementation, a full depreciation level is not allowed for the DSO to the extent that the introduced components are not capitalised, as part of this difference in costs caused by the lag in accounting is cut off from the permitted depreciation using the benefit cutting system. In other words, the apparent efficiency resulting from slow accounting is normally interpreted as investment efficiency, in which case part of this efficiency is attributed to the customer and thus the principle reduces the incentive to increase efficiency through slow accounting.

The Energy Authority has estimated that 85% of the efficiency gains from straight-line depreciation will continue to be left to the benefit of the DSO, to ensure that the DSO will have an incentive to invest in cost-effective solutions, which also continue to serve the best interest of customers. Therefore, 15% of the additional benefits from straight-line depreciations are allocated to customers. Emphasising the share of benefit provided to the DSO can be considered justified because the customer receives the full benefit immediately, whereas the DSO has to wait towards the end of the component life cycle before reaping actual benefits.

The steering impacts of the investment incentive have also been highlighted in the opinions and comments received by the Energy Authority. It has been pointed out that if the value of the whole network mass is always adjusted at unit prices and if the investment incentive is subject to the benefit cutting system, this may in certain cases guide individual DSOs to raise their investment costs. However, this problem cannot now arise in the same way as before, because of the use of the nominal rate of return and the adjustment principle required by it, in which the old mass is not revalued at new unit prices. Based on the new valuation principle required by the nominal rate of return, the investment incentive works appropriately and correctly in terms of its steering effects when efficient companies benefit from their cost-effective years of investment until the end of the component life cycle, and updating the new unit prices does not affect this gain.

The opinions also pointed out that the benefit cutting system could be symmetrical. The Energy Authority notes that a similar principle is not appropriate in terms of its steering effects. If a higher depreciation level in the benefit cutting system would be allowed for companies that have invested inefficiently, it would significantly reduce the incentive to invest in a cost-effective manner and, on the contrary, encourage inefficient investments. In this case, inefficient companies would be allowed to have costs exceeding a reasonable average level of costs and there would no longer be any restrictions on the valuation of investments. The main criterion for unit prices is precisely to limit inefficient investments and to ensure that customers do not have to pay the costs of inefficiency.

3.3.2 Elimination of separate inflation adjustment for straight-line depreciation

The use of a separate inflation adjustment for straight-line depreciation is not justified. The determination of the straight-line depreciation depends directly on the determination of the rate of return and the adjustment of network assets principle used for calculating the replacement value that this requires. In other words, if the real rate of return and the revaluation of the total network mass required by it were used annually, the change caused by inflation would be taken into consideration during the regulatory period in the replacement value by an annual index adjustment of the unit prices. As the principle required by the nominal rate of return is used as the adjustment, the criteria are not met for separately including inflation in the network assets or depreciation level.

With reference to the above, where the methodology uses a nominal rate of return, the calculation of straight-line depreciation must be based directly on the frozen replacement value divided during the lifetime determined on the basis of the principle of the nominal rate of return.

3.4 Innovation incentive

The Energy Authority will also retain the innovation incentive as a part of the regulation methods in the sixth and seventh regulatory periods. Encouraging DSOs to engage in innovative activities was also highlighted in the publication by CEER[33] as an important part of the regulators' activities. One of the perspectives highlighted in the CEER publication included the increasing digitalisation of energy services and the opportunities this brings to new business solutions. The Energy Authority wants to encourage DSOs to develop such opportunities.

The permitted share of costs recorded in the innovation incentive will change from 1% of the total network turnover of the DSO's unbundled profit and loss account from the regulatory period used in the previous regulatory periods so that, in the sixth and seventh regulatory periods, a share corresponding to 0.5% of the total network turnover of the DSO's unbundled profit and loss account from the period can be accepted to the innovation incentive. The Energy Authority justifies the change above all with the aim of shifting the focus of the incentive towards the development of flexible solutions. The flexibility incentive is presented as a new incentive for future regulatory periods, and therefore no further solutions purely aimed at developing flexibility would be accepted as a part of the innovation incentive. It is appropriate to link both innovation and flexibility incentives more closely together and to enable the DSOs to have a combined incentive effect of up to 1.5%, taking both incentives into account. The Energy Authority also notes that the current use of the innovation incentive has not been very high among DSOs, and the DSOs have not utilised the full impact of the incentive in the previous regulatory periods.

3.5 Flexibility incentive

3.5.1 Flexibility incentive during the sixth regulatory period

The Energy Authority presents a new incentive for the regulation methods, the purpose of which is to encourage DSOs to develop and utilise flexibility solutions as a part of electricity network operations. Under Article 32 of Directive 2019/944, Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services. In order to develop flexibility in the sixth regulatory period, the Energy Authority will implement the flexibility incentive in which DSOs can record at maximum a share corresponding to 1% of their total turnover from network operations in the unbundled profit and loss accounts. The flexibility market is currently undeveloped, so during

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the sixth regulatory period, the Energy Authority aims to encourage distribution system operators to develop market solutions.

3.5.2 Flexibility incentive in the seventh regulatory period

As mentioned above, the flexibility market is currently undeveloped. For this reason, during the sixth regulatory period, the Energy Authority’s specific aim is to encourage DSOs to develop market solutions. Meanwhile, in the seventh regulatory period, the aim is to encourage the DSOs to integrate flexibility solutions developed during the previous regulatory period into their daily activities. When formulating the flexibility incentive, the Energy Authority has taken into account the overall benefits for all parties. From the perspective of the Energy Authority, the greatest overall benefit will be achieved by utilising market-based flexibility solutions, which is why the requirement of a market basis for flexible services will be emphasised especially during the seventh regulatory period. Therefore, the Energy Authority proposes an opportunity to treat the costs of flexibility solutions obtained to the flexibility incentive on a market basis as pass-through items with up to 2% sum of the DSO's turnover in the unbundled profit and loss account during the regulatory period.

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