Feedback on draft business plan: SSEN

The RIIO-2 Challenge Group has been established by Ofgem as part of the RIIO-2 enhanced engagement process, in order to strengthen the voice of current and future consumers in network price controls. The Challenge Group's objective is to provide an independent challenge to ensure that regulated network companies deliver the value-for-money services that are needed, with particular regard to affordability, the protection of vulnerable consumers, and the transition to Net Zero.

As part of this role, Ofgem has asked the Challenge Group to provide scrutiny of all draft business plans submitted by network companies in the course of RIIO-ED2. Our feedback on the draft business plan that you submitted on 1 July 2021 follows below.

The Challenge Group recognises the challenging nature of the work that the DNOs are being asked to carry out during the period of RIIO-ED2, and its crucial importance. In what follows, as per our remit, we have generally focussed on areas where we feel there is room for improvement. This is not to detract from the standard of your planning and its broader implications. Where we focus on affordability, we recognise that other disadvantages may be at stake if the networks are not upgraded as required, and where we focus on your environmental impacts, we recognise that other environmental benefits may be enabled by those upgrades. Nonetheless, affordability and sustainability remain vital considerations. The Challenge Group is keen that no contradiction should be seen between a business plan that meets the coming challenges and one that provides value-for-money, mitigates environmental impacts and supports vulnerable consumers.

Our feedback focuses on three areas:

1. Costs, scenarios, and DSO and whole system proposals
2. Outputs:
    i. EAP
    ii. Vulnerability strategy
    iii. Reliability
3. Finance

We expect this feedback to be reflected in the final business plan submitted on 1 December 2021.

1. Costs, scenarios, and DSO and whole system proposals

This note summarises our initial comments. Additional detail is provided in a supporting annex.

1. ED1 Track record

You are forecasting a 3.4% totex overspend for ED1, and that output targets will be met or exceeded. Asset heath delivery is largely on track. ED1 demand was below forecast. You have provided limited information on demand and network utilisation parameters to show the

expected network capacity position at the start of ED2 - we suggest this analysis should be included in the final plan.

2. *Scenarios and forecasts*

Your baseline scenario for LRE assumptions appears to be Net Zero compliant, which is welcome, but we find it difficult to relate this scenario and the assumptions for low carbon technologies to the network demand forecasts used in the plan. Your forecasts for heat pumps appear to be higher than might be anticipated for the chosen scenarios.

We would welcome clarification about how the demand and LCT forecasts have been derived, how they have been applied in the plan LRE assumptions, and a clear demonstration of consistency with common industry scenarios.

3. *Totex overview (£4129m)*[1]

We have reviewed your totex data submitted in your business plan data tables (BPDT). Your baseline totex proposal for ED2 represents a 44% increase over average annual ED1 expenditure. A profile of the overall totex plan and main expenditure categories is shown below, showing a significant increase at the start of ED2.

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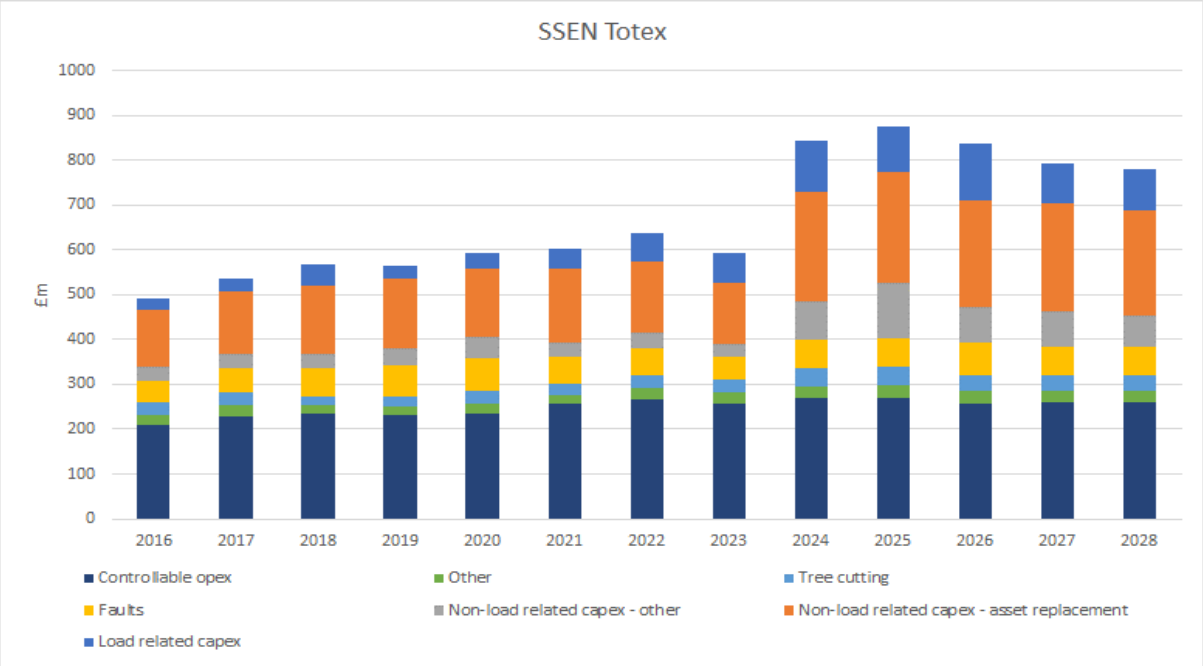


The following table compares the changes in the main totex cost categories in company plans between ED-1 and ED2. These cost categories are reviewed further below. While we think the following comparisons are representative, we have observed some inconsistencies in assumptions used in supporting data tables for DNO ED-1 track records and ED-2 baseline totex bids. For final plans we would request that the bids for the baseline totex

[1] All totex figures quoted have been taken from the equivalent company BPDT or PCFM submissions for consistency. This may result in differences with numbers quoted in business plans. We have not attempted to reconcile these differences or differences between company assumptions at this stage.

(within the price control) are clear and are based on consistent assumptions so that we may assess proposed changes with ED-1, and between DNOs.

	ED-1 Average Totex	ED-2 Average Totex	% change	LR Capex	NLR capex - assets	NLR capex - other	Opex
ENWL	259	400	54%	180%	68%	124%	24%
SPEN	504	641	27%	107%	15%	188%	7%
SSEN	573	826	44%	152%	62%	150%	13%
WPD	1050	1332	27%	134%	15%	118%	6%
UKPN	831	869	5%	27%	5%	48%	-4%
NPg	470	641	36%	351%	12%	100%	10%
Total	3686	4709	28%	128%	24%	110%	6%

a) *Load related expenditure (LRE): £528m*

Your average annual LRE is expected to increase by 152% between ED1 and ED2 with the large increases in all cost categories. Your upper view adds another £211m to this forecast. We don't think the expenditure assumptions have been justified and would like additional clarification about investment included in baseline, upper view and in uncertainty mechanisms, together with reasons for prioritising expenditure at the start of ED2. The impact of potential downward cost drivers such as falling demand, capacity headroom, flexibility, and network visibility should also be addressed. For your final plan, we would like to see justifications why additional LRE is required during ED2 given that your peak demand by 2028 appears not to reach your historic levels.

b) *Non-load related capex – assets: £1205m*

This cost category increases by around 62% between ED1 and ED2. This includes a number of asset related cost categories, and of these, asset replacement expenditure for asset health reasons is forecast to increase by 7%. Overall, we don't think these expenditure increases for ED2 have been justified given that the asset base remains largely the same as for ED1. We are concerned that the ED2 increase in this cost category is due to expenditure being deferred to ED2 and customers having to pay twice for the same activities. We would expect these costs to remain stable or potentially reduce as efficiency savings are applied, and would like to see justification that the proposed investment increases are necessary. In your final plan we would like to see clear evidence for any expected change in asset health risk and associated expenditure.

c) *Non-load related capex – other: £435m*

This cost category increases by around 150% between ED1 and ED2, due to significant increases in IT, telecoms and property expenditures. While we welcome expenditure that delivers enhanced network visibility and flexibility, forecast benefits from flexibility appear low. We would like to see enhanced justifications that benefits will be delivered from this increased investment.

d) Opex[2] and efficiency: £1827m

You forecast a 13% increase in operating costs between ED1 and ED2 (including network operating costs, business support and closely associated indirects). Justifications for these increases are high level and we are concerned that efficiency opportunities have not been sought. We suggest you consider opportunities to hold these costs flat during ED2.

A 0.5% ongoing efficiency challenge has been included which we suggest should be increased to the 1-1.2% levels as for the 2020 RIIO-2 price control decisions.

4. Uncertainty mechanisms

You have proposed several bespoke uncertainty mechanisms and present a range of about minus £80m to plus £700m–900m to address these uncertainties. We agree that it could be appropriate to include LRE uncertainty mechanisms but would like to see evidence that these are appropriately calibrated in terms of costs, volumes and triggers, and do not provide windfall gains for companies. However, we think the other uncertainty mechanisms relate to cost risks that are best assessed and managed by the company and should not be passed to consumers. For your final plan we would like to see evidence to support the calibration of proposed uncertainty mechanisms including the baseline totex assumptions.

5. DSO and digitalisation

You are proposing to spend £98m on DSO activities in ED2 compared to £20m for ED1 and are targeting 19% of secondary substations to have metering installed. Flexibility markets are expected to defer reinforcement by £27-58m over ED2. Your flexible connections proposals aim to help customers avoid £417m of expenditure in the longer term. Your DSO and digitalisation plans are high level. There is limited evidence to give confidence that the plan can deliver benefits from the significant increase in expenditure and planned activities.

We welcome the initiatives that you are planning for digitalisation and DSO but are concerned that the enhancements and benefits are inwardly focused and may not allow all benefits to be sought from external market participants. A network-centric vision may block routes to other electricity markets, including community models. We suggest that the enabling technologies and processes should be further considered.

Overall in your final plan, we would like to see a clear justification for costs and benefits associated with your DSO and enabling investments. This should include benefits from distributed energy resources to enhance resilience, from active network management, and from interaction with the ESO.

6. Whole system

Your whole system plan is based around a business transformation plan to embed new thinking and practices across the organisation, which is welcome. Also proposals to work with Local Authorities and community groups to help them transition to NetZero appear promising. However, the plan does appear to be predominantly focused on electricity

[2] Opex includes tree cutting, faults, revenue pool expenditure and controllable opex.

system activities and the ultimate identification and delivery of whole system benefits seems uncertain.

2.i. EAP

In reviewing the environmental commitments and EAPs in all the draft plans we have focused on decarbonisation. This is not to undermine the importance of other commitments to address environmental impact but given the need for this price control to be focused on the pathway to Net Zero, and the excellent work which stakeholders and CEGs have done in challenging all the companies in relation to all aspects of their EAPs, this seemed the area where it would be most valuable to look across the plans.

Overall, vision, strategy and longer term goals are well articulated in the EAP and the approach to assessment of environmental impact seems comprehensive and holistic. Your proposed science based target (SBT) target of 2033 is aligned with anticipated grid decarbonisation and end of ED3, is clearly articulated. Benchmarking included in the EAP shows recognition of the scale of the challenge and a commendable aim to compare performance across sectors.

However, we have been unable to reconcile the plans in the EAP with the forecasts in the BPDT. In the EAP, you commit to reduce emissions (excluding scope 3) in line with a 1.5°C SBT, which would mean a reduction of 35% against 2019/20 levels by the end of ED2. But the BPDT figures for scope 1 and 2 excluding losses suggest a decrease of only 7% over the same period, and a slight increase in scope 1. You also raise a similar problem on losses emissions. As it stands, therefore, the submission gives limited confidence of your ability to meet the SBT, with losses or without.

Although you give a reasonably detailed account of the steps you will take to reduce your scope 1 and 2 emissions excluding losses, this is not sufficiently linked to targets in each area (operational transport, buildings etc.) and in several areas such as energy efficiency they are still under development. In particular, the diesel strategy sets targets for process rather than BCF outcome. If you expect your diesel emissions to increase in ED2, please state this clearly, and by how much. We were also surprised by the scale of proposed expenditure on afforestation, which is partly to provide future carbon sink, and would expect to see much clearer justification and exploration of costed options.

You intend to announce a voluntary target for scope 3 emissions later in 2021. While this is a reasonable approach, the very low scope 3 emissions recorded in the latest year and forecast for 2028 in the BPDT suggest that there is more work to do in setting an appropriately wide boundary. In line with SBTi guidance on scope 3, your proposed SBT includes a target for a certain proportion of your supply chain to have signed up for their own SBT by 2026/27 and 2033. This is a useful complement to your forthcoming direct target on scope 3.

You propose a target of a 35% reduction in SF_6 leakage in ED2. This is an ambitious target and is welcome given your historically poor performance. You are proposing a PCD on SF_6.

You will not be publishing a full SF_6 strategy until your final submission but a useful outline included in the draft suggests that your thinking in this area is reasonably well developed.

You are forecasting emissions from losses to rise in ED2. No target for losses reduction is proposed, and only minimal other performance measures are mentioned. You do not intend to publish your full losses strategy until your final Business Plan. Most of the losses section of the EAP is given over to two case studies, but one relates to less than 0.1% of your total losses, and the other, on improving the efficiency of substation buildings, seems only minimally relevant. It would be good to see the quantification and justification of actions and benefits to tackle losses set out more clearly.

Questions and challenges

- Overarching challenge: please ensure that ED1 performance, proposed actions and benefits are expressed as clearly as possible, in consistent units (ideally both in absolute and percentage terms) and that baselines are identified and justified.
- Please explain the figures in the BPDT for scope 1 and 2 and how they reconcile to SBT. How confident are you that you can achieve the reductions required by the SBT?
- The Climate Group's EV100 target will lead to early electrification – is this cost efficient given current state of market? What other options have been considered?

2.ii. Vulnerability strategy

We welcome the following points in your vulnerability strategy.

- It acknowledges that you have been behind your peers in terms of ED1 performance and says you will continue to review your approach and services in advance of ED2.
- The 'strategy wheel' device is a clear way to show the relationship between priorities, tools/processes and targets. We particularly welcome the target for £/customer benefit levels.
- It gives a clear articulation of how you use data to understand PSR gaps in terms of different needs and to prioritise further activity. It shares an actionable insight that you have learned that customers are more likely to sign up to the PSR if they receive sign up information at the same time as other practical details – for example, when they are being discharged from hospital.
- It proposes more outcomes-based PSR metrics including 'PSR gap' – with a target of 28% by the end of ED2, and '% of households deemed accurate on PSR every 2 years'.
- You will operate a new business support register for business customers by 2023, following stakeholder feedback.

Questions and challenges

The main themes of our questions and challenges are that your final plan should:

- Do more to define and measure the outcomes that you are aiming to achieve with your activities in this area

- Provide a detailed plan for how you will deliver your strategy, particularly when you are committing to a significant increase in activity
- Set out a clear justification for why you, as a DNO, are best placed to deliver your proposed activities.

- PSR reach: We want to compare the reach of DNOs' PSRs on a like for like basis. By 'reach' we mean the proportion of all and eligible customers who are registered. We are therefore asking all DNOs to clarify:
    - Your current (ED1 actual) and targeted (for ED2) reach as a percentage of all customers.
    - Your current and targeted reach as a percentage of eligible customers (i.e. all those who fall into any of the MDD PSR needs codes).
    - A breakdown of the percentage of eligible customers registered by each needs code.
    - If you use a definition of eligibility other than the full set of needs codes, please explain what this is, why you use it, and what your current and targeted reach is as a percentage of this group of eligible customers.

  Throughout, please be clear whether you are talking about individual customers or households, and what multiplication factor you are using if relevant. Please also give details of any customer groups that you define as 'high priority' and the reasons for this prioritisation. To what extent and in what way will your PSR recruitment be targeted on high priority groups?
- PSR quality: When you contact customers in an attempt to keep the PSR up to date, how do you assess the effectiveness of this activity and its impact on data quality? You say you will measure '% of households deemed accurate on the PSR'. How do you deem this data to be accurate, what level of accuracy are you targeting, and what is the comparable figure for ED1? What other criteria, if any, do you use to 'cleanse' PSR data and to remove people from the register?
- Impact of your support during a power cut: Other than the headline customer satisfaction metric, how do you currently measure the impact, reach and relevance of services that you provide to customers in vulnerable circumstances during a power cut? To what extent have you assessed any gaps between the specific needs of different groups of customers and the impact of the support that you offer? In what ways will the ED2 services that you offer to customers during a power cut be targeted on people with different needs?
- Fuel poverty: You say you will support 50k households in fuel poverty in ED2 (or 10k per year) compared with c3.8k this year. How was 50k decided on as the optimum number (other than via stakeholder support) and what evidence (from tests or trials, for example) can you provide that gives confidence that your targets are achievable? Can you also explain the assumptions you have made to calculate the £9.1m of value that 'helping with energy efficiency' will achieve. What plans do you have to measure the actual benefit achieved by customers?
- Education material: You say you will produce education material on LCTs and EVs with partners and distribute it through local community groups. What evidence do you have that this approach is likely to be effective? How will you prioritise the use of the £250k fund you have allocated to help customers with the take up of LCTs and EVs? What support do you have from consumers or stakeholders for this type of direct

financial help? We understand that this £250k cost will be funded by shareholders, with the implication that it will not be passed on to bill payers. What assurance can you provide that this claim is meaningful?

- Culture: How will you measure whether you are being successful in embedding a culture of understanding and responding to the needs of consumers in vulnerable circumstances across the business? In terms of the training you propose, how will you measure its impact or success?
- Costs: Please clarify: your total expenditure on vulnerability-related activities in ED1 (including any costs that are 'funded' by shareholders) with a breakdown by the main areas of activity. Please do the same for your proposed expenditure in ED2.
- CVPs:
    - Regarding your proposed CVP on 'personal resilience plans', how developed is this idea? Have you trialled it with partners or some customers, for example? How does it differ from any current proactive work you do to identify and support customers on your PSR?
    - You say you will offer it to all newly registered PSR customers (and most medically vulnerable customers already on the PSR). What is the reasoning behind this prioritisation?
    - What will the costs and benefits be?

2.iii. Reliability

Compared with other DNOs, you have had the worst reliability performance in ED1, and did not achieve your target for customer minutes lost in 2019/20. You are targeting a '20% reduction' in both customer interruptions (CI) and customer minutes lost (CML) in ED2, although given your performance in ED1 this might still leave your customers in both regions with comparatively poor reliability. You are also aiming to 'remove at least 75% of customers from our worst-served customer list' at a cost of £35.5m in your Scottish network and £3.3m in southern England.

Questions and challenges

- CI and CML targets: how have you weighed up the relative levels of investment in overall reliability improvements compared with those benefiting worst-served customers given than your overall performance is currently weakest of all DNOs and likely to remain so in ED2?
- Worst-served customers: what is the current experience in terms of number and length of outages for your worst-served customers and what would it be after your current plans are delivered? Can you confirm that your target to remove 75% of customers from your WSC list is using Ofgem's new definition of WSC?

3. Finance

We were pleased to note that the finance section of your Plan was very largely compliant with the requirements set out by Ofgem in the Sector Specific Methodology (SSMD) and that you have carried out, and presented clearly, the full scenario analysis requested.

Although there are a number of positive aspects to your Plan, there are some areas which we consider need attention before submission of your Final Business Plan (FBP):

- You express reservations about the concept of the outperformance allowance. You should be aware that we concur with Ofgem's stance on outperformance and that we consider it to be very well supported by historic evidence. We expect to continue to be supportive of any measures which Ofgem decides to take to address this issue;
- You are targeting a rating of BBB+/Baa1 in the base case for both the Notional and the Actual Companies. It is in our view clear from the results of your scenario analysis that you can expect to attain that rating. As you will know, Ofgem takes the view that it is for individual DNOs to select their target rating for the Actual Company, subject only to a licence requirement that that rating never falls below investment grade (and now with arrangements that Ofgem must be alerted if there is an immediate risk that it falls below that level). Because the maintenance of an investment grade rating is a licence requirement, your target rating is clearly a significant consideration but we also regard it as important that consumers are not impacted by an excessively high target rating for either the Notional Company, on which Ofgem bases its individual financeability assessment, or the Actual Company which impacts its generic view of the cost of financing the sector. In that context, we regard BBB+/Baa1 as at the upper end of the acceptable target range;
- We note the statement on page 15 of your Plan that your Board has 'acknowledged and confirmed that the Directors are satisfied that the licensee is financeable on both a notional and actual capital structure . . .'. That section of your Plan goes on to 'acknowledge and confirm' that the Board were satisfied that your draft Plan provided the 'level of assurance required by and in compliance with the terms of the Ofgem Business Plan Guidance'. We consider that those two statements, when taken constitute a clear indication that your Board considers your Plan to be financeable on the basis of the W/As set out in the Business Plan Guidance. You indicate that that is not, in fact, the case. This is an important area for clarity and we suggest that your final Business Plan incorporates an unambiguous statement as to the financeability of your Plan on the basis of Ofgem's W/As. As far as the underlying position is concerned, we have, of course reviewed both Section F of, and Annex 29 to, your Plan. It is true that there is some pressure on credit metrics in the financial projections you have shown but we do not believe these are such as to make your Plan unfinanceable on the basis of Ofgem's W/As for the Cost of Capital. To the extent that there are difficulties, we do not consider the most appropriate remedy to be a 6.75% Cost of Equity allowance. The proposal is not, in our view, in the interest of consumers: you may wish to reconsider it before submission of your FBP. We do not, in any case, support the concept that it is appropriate to change the Cost of Equity allowance to support the varying requests of, and issues relating to, different DNOs**;**
- You should be aware that we are supportive of Ofgem's proposed Cost of Capital allowances which we regard as based on sustainable Capital Asset Pricing Model (CAPM) analysis with appropriate cross-checking. The clear evidence of appetite for the acquisition of utility distribution companies – and at a very substantial premium to

RAV - does not support an argument that Ofgem's analysis of the WACC appropriate to DNOs and hence its Cost of Capital W/As are miscalculated. We also consider that the extent to which expenditure in ED2 will be subject to adjustment arrangements (uncertainty mechanisms and other) and the escalation arrangements which Ofgem proposes in relation to the cost of both debt and, through adjustment of the risk free rate, equity, are indicative of a significant lowering of the risk profile for DNOs as against that in ED1. They are not, therefore, in our view, supportive of an increase in Ofgem's Cost of Capital allowances over those currently proposed;

- You say that you do not consider it appropriate to adjust either depreciation or capitalisation rates to improve financeability (apart from a potential one-off change in the capitalisation rate in relation to the Shetland Link). We think it important that you examine whether there may be benefits from doing so in terms of costs to consumers. In the same vein, we believe you should demonstrate that you have explored whether alternative levels of gearing might be beneficial to consumers;
- We note that, although you have presented analysis compliant with Ofgem's W/A for the Cost of Debt allowance, you have proposed that it be increased to incorporate a small company premium. It is clearly for individual DNOs to determine their debt funding strategies and the extent to which they implement those strategies on a group-wide basis but you should be aware that we can see no reason for a small company premium in the Cost of Debt allowance.

Annex: assessment of costs, scenarios, and DSO and whole system proposals

This annex sets out our supporting comments on the SSEN July plan. In each of the following areas we have set out what we are looking for in each plan and our observations about the draft plan.

1. Scenarios and forecasts

We are seeking to understand how the companies have aligned their forecasts with Net Zero objectives, as set out in the FES and 6th Carbon Budget and take account of any local customer-led drivers. We wish to see how these forecasts lead to investment at different network voltages, including where flexibility resources will be used instead of investment.

SSEN has used the ESO FES as the starting point for their own DFES. There is evidence that stakeholders have helped inform their forecasts but it's difficult to see which suggestions have been adopted or rejected. The FES Consumer Transformation scenario has been used as the baseline future pathway for the draft SSEN Business Plan. This is the FES scenario which has the highest level of ASHP heating and uptake of EVs. The plan has used this scenario for funding in years 1 and 2 with a lower electricity heating scenario (System Transformation) being used for the following years.

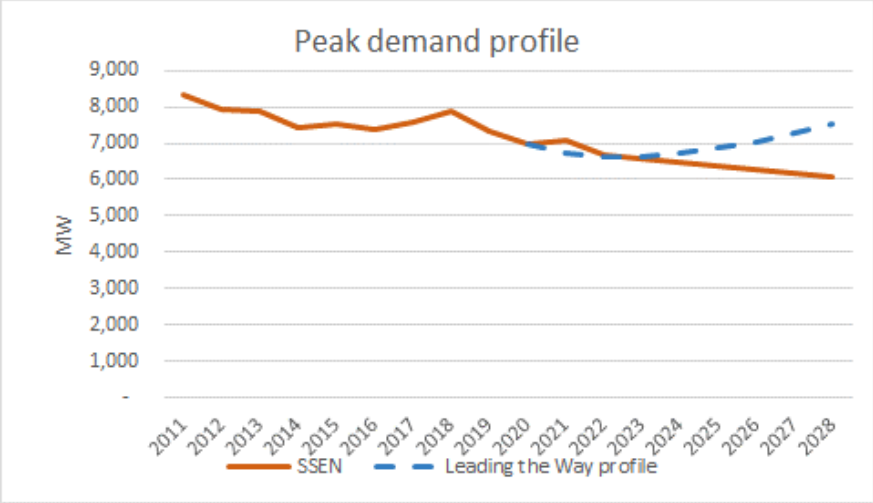
By the end of ED-2, SSEN forecast they will connect

- 993,674 EV's and 503,493 heat pumps by 2028 under their Best view scenario and
- 1,344,071 EV's and 805, 573 heat pumps under their Upper view scenario.

SSEN has around 13.1% of the Networks' customer base. The forecast number of EVs across this customer base in 2028 is broadly in line with the ESO FES Consumer Transformation scenario which forecasts 7.7m BEVs (cars + vans). The forecast number of EVs is not in line with the System Transformation scenario which SSEN states is the basis for its 2028 forecasts and forms part of its justification for LRE Uncertainty Mechanisms.

However, SSEN's forecast for ASHPs, including hybrids, is considerably greater than is consistent with the ESO FES Consumer Transformation or System Transformation scenarios. We would welcome a clear explanation of this.

We welcome that the SSEN plan has used scenarios with Net Zero targets but we find it difficult to relate these scenarios to the system demand forecasts. For example, the SSEN submission of demand profiles in the BPDTs shows a decrease between 2020 and 2028. The following chart shows the relative forecasts SSEN and the ESO (Leading the Way) forecast, which they consider to be the fastest credible pathway to Net Zero targets. The SSEN profile (from BPDTs) shows a decline of 13% between 2020 and 2028, whereas the ESO profile increases by 8%.

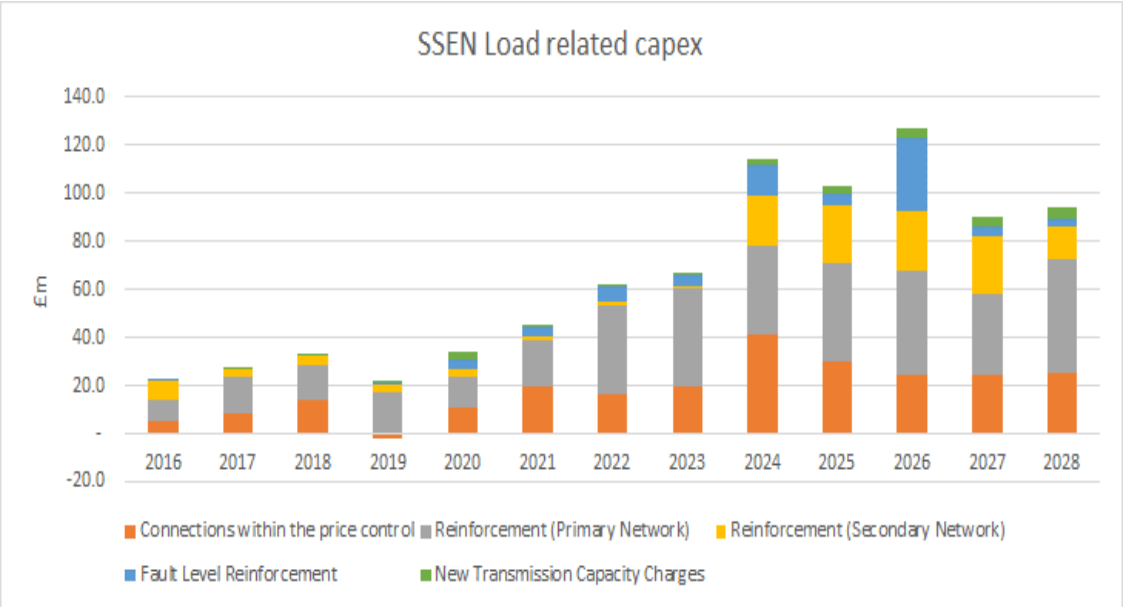


2. Totex - Load related capex

We are seeking to understand company investment pathways for load related expenditure, and how they have taken account of:

- Historic levels of network utilisation and reinforcement expenditure
- Downward cost drivers, including efficiencies, innovation and flexibility
- Upward cost drivers including demand scenarios and anticipatory investment

We are looking for evidence from EJPs and CBAs which justify costs, volumes and timings of expenditure together with uncertainty mechanisms where justified and PCDs to provide delivery certainty.



SSEN	£m	% change
Total load related capex	**528**	**152%**
Connections	146	155%
Primary reinforcement	201	94%
Secondary reinforcement	107	576%
Fault levels	55	353%

SSEN's baseline load related capex profile is shown in the above chart and table, totalling £528m in the ED2 period. SSEN's upper forecast adds an additional £211m to this baseline.

We would welcome a quantified description of the path from the scenarios to the demand forecasts used to justify the levels of assumed investment at different voltages, and then to the investment profiles for the above categories. We would welcome clarification on which schemes are anticipatory (if any) and a clear linkage to the associated PCD.

There is evidence that flexibility and system losses are being considered in the EJPs. For larger schemes, further evidence is required that a reasonable range of options have been considered, not just non-credible ones which are summarily dismissed.

There is little evidence that flexibility assumptions have been used to reduce this capex profile. The investment profiles show a significant increase at the start of ED-2 which does not appear to be linked to the demand and network utilisation profiles. This may lead to inaccurate prioritisation of investment needs and consequent inefficiencies.

3. NLRE totex for ED2

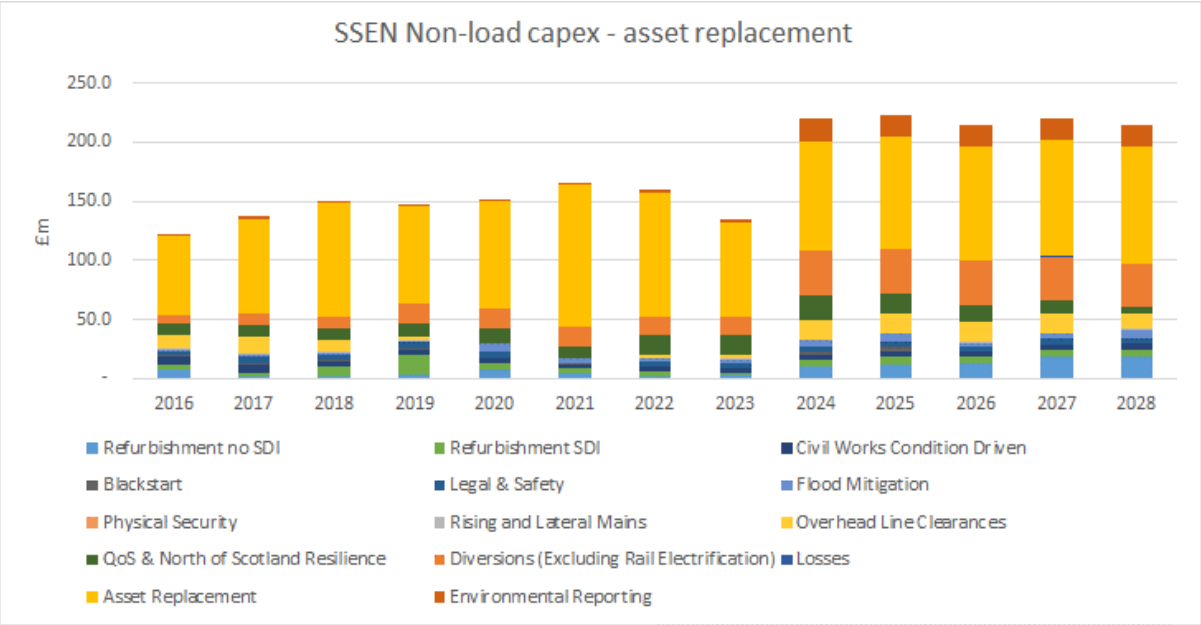
As in the case of LRE totex, we are seeking to understand company investment pathways for non-load related expenditure, and, again, how they have taken account of:

- Historic levels of non-load related expenditure, asset health and reliability levels
- Downward cost drivers, including efficiencies, intervention options, and innovation
- Upward cost drivers including demand scenarios and anticipatory investment

We are looking for evidence from EJPs and CBAs which justify costs, volumes and timings of baseline expenditure to deliver asset health and reliability outputs during ED2, including PCDs where appropriate to provide delivery certainty. We are also looking for evidence that, where a higher rating for a replacement asset is proposed, utilisation and load data is provided to justify this and that due consideration has been given to replacement vs refurbishment.

We have examined SSEN's proposals for a) NLRE - asset replacement and b) NLRE - other. The NLRE asset replacement profile is shown below, together with the major changes between average ED1 and ED2 expenditures.

NLRE – asset replacement

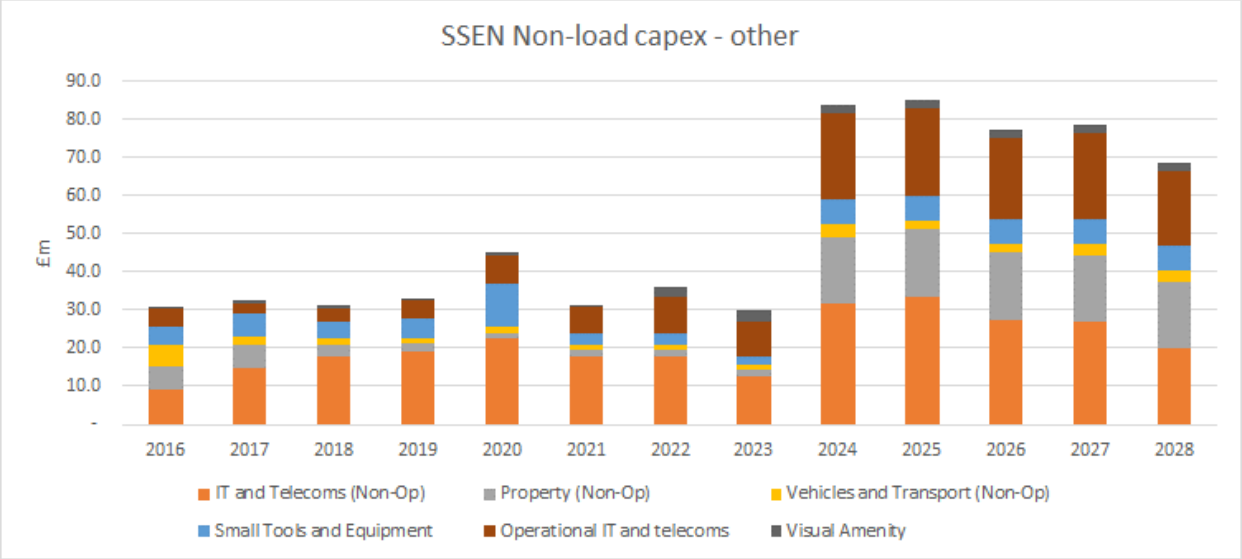


The above table shows significant increases in several cost categories, including diversions and overhead line clearances. SSEN evidence for increased expenditure includes potential increases from 'injurious affection' claims and overhead line clearance issues. SSEN's business plan states that their overall capital investment is reducing from £755m in ED1 to £732m in ED2 and we would welcome clarification of how this is consistent with the above submission.

Overall, we do not think the expenditure increase for ED2 above that for ED1 has been well justified. SSEN are continuing to maintain largely the same assets as ED1 and we would expect costs to remain stable or reduce as efficiency savings are applied.

NLRE – other

The following chart shows the forecast profile for NLRE – other. There is an average increase of 150% from ED1 driven by significant increases in IT/telecoms and also in property.



We welcome additional expenditure where it delivers enhanced network visibility and flexibility markets and would like to see justifications that show how these enhanced outputs are delivered effectively and efficiently. We would question whether additional property and other expenditure offer value for money.

4. Totex - Opex and efficiencies for ED2

SSEN's average operating costs increase by 13% overall for ED-2 compared with ED-1, with business support costs increasing by 23%.

SSEN	£m	% change
Total Operating costs	**1,962**	**13%**
Network operating costs	698	19%
Closely associated Indirects	681	13%
Business support costs	409	23%

SSEN justify this increase due to the increased capital delivery programme across load and non-load programmes. However, as set out above we have concerns with the efficiency of these proposed expenditure programmes.

While explanations for annualised cost increases are detailed, we are concerned that the same analysis and efficiency opportunities have not been applied with corresponding rigour, and these costs may be overstated as a result.

Overall, SSEN have proposed a 0.5% pa efficiency challenge for ED-2 which we think is unambitious. We think that this efficiency challenge should be set at levels equivalent to those proposed for electricity and gas transmission and gas distribution i.e. an ongoing efficiency challenge of 1.15% p.a for capex and 1.2% pa for opex.

We note that the common cost sources used in your plan forecast are RIIO-ED1 actual unit costs with an additional 2.5% (SHEPD)/5% (SEPD) assumed efficiency where these are above upper quartile rates in asset replacement, together with costs derived through competitive tendering processes and market cost data. We welcome that SSEN will seek third party assurance of these costs for the final business plan.

5. Bespoke uncertainty mechanisms

SSEN have proposed the following additional bespoke uncertainty mechanisms for ED-2. The total range of the costs SSEN propose to address by UMs relative to the ED2 baseline is around -£80m to +£900m, but several potential costs are unquantified so this value may be higher.

Category	Risk addressed	Mechanism	Cost
1. Wayleaves and diversions	Uncertain diversion costs following wayleave determinations	Reopener	£49.3m included in totex.
2. Shetland	Uncertain costs of providing an enduring supply, incl. back up after new transmission link completed	Re-openers and pass through	£93.8m included in totex
3. Subsea cables	Uncertain subsea cable replacement costs	Volume drivers and reopeners	Baseline costs do not include reactive replacement, fuel & decommissioning costs.
4. Radio spectrum allocation	Costs of construction of new private communications network, if needed following Gov't spectrum allocation	Re-opener	Not specified
5. DG monitoring	Costs of additional monitoring equipment, if needed by Ofgem review	Re-opener	Not specified
6. PCB asset replacement	Costs to meet legislative requirements	Volume driver	Not specified
7. Ash dieback tree removal	Costs of removing diseased trees near network	Re-opener	Not specified
8. Strategic load related investment	Uncertain load related expenditure due to increased electricity demand	Volume driver	£388.1m included in totex
9. Access SCR	Uncertain costs arising from regulation change	Re-opener	Not specified
10. LV network Monitoring?	Uncertain costs of LV monitoring equipment	Volume driver	[redacted]m included in operational IT

We think most of these risks are best managed by the company and should not be passed to customers. Addressing such risks through uncertainty mechanisms means that the company may be disincentivised to manage the risk effectively, instead seeking to prioritise additional revenue allowances through price control uncertainty mechanisms.

Our specific comments on these risks are:

- Strategic load related investment – (-£39m to £209m) we agree that this is a risk that could be covered in a volume driver uncertainty mechanism. We would like to see greater detail provided on how these estimates are derived, and how the mechanism will balance the risk between company and customers. We think a utilisation metric is a key part of any such mechanism.
- Shetland – a set of UMs are proposed to fund standby supply costs before and after the Shetland transmission link becomes operational in 2024. Baseline costs of £94m have been assumed and an uncertainty range of +£20/-£13m appears to apply. Given that network failure risks on Shetland will fall significantly after the transmission link is commissioned, and that these potential variations form a small proportion of SSEN overall totex, we question whether this reduced risk should be continue to be managed through the price control uncertainty mechanisms.
- Subsea cables – SSEN identify that they will have allocated £171m for cable replacement, inspection and maintenance, and have proposed upwards volume drivers (only triggered by SSEN) for additional expenditures, covering cable replacement, back-up generation, cable decommissioning. Potential additional costs have not been fully identified but could be in excess of £76m. We think that SSEN's considerable experience of cable operation mean it is best placed to manage these costs through a baseline allowance without UMs.
- Others - Wayleave determinations, LV network modelling, radio spectrum allocation, DG monitoring, PCB asset replacement, ash dieback – these all appear to be activities where SSEN are best placed to manage them as part of its ongoing business activity. We don't think these are risks that should lie with consumers and be addressed by uncertainty mechanisms.

6. DSO and digitalisation, and whole system strategy

We are seeking to understand how DNO plans will demonstrate delivery of:

- Digitalisation, providing high visibility of network utilisation and available capacity
- DSO functions, especially for third party access to flexibility markets,

We are seeking to understand proposed costs and benefits from these DSO initiatives, including how this ambition exceeds business as usual expectations. These include benefits from working with the ESO.

<u>DSO and digitalisation</u>

SSEN set out the following parameters for their DSO activities:

- Network visibility - at end ED1, SSEN will have 2% of Secondary substations with demand monitoring, and are targeting 19% by end of ED2.
- Flexibility markets – 5GW of MW procured over ED2, avoiding £27-58m of investment. ED1 forecast is 2GW.
- Costs - SSEN's DSO costs are £20m for ED-1, supported by £160m+ on systems to build DSO capabilities. SSEN are proposing to spend £98m in ED-2 including £75.1m of new DSO investment and other ongoing costs.

SSEN's plan proposes to invest this £75.1m to deliver these DSO capabilities and meet the minimum requirements laid out by Ofgem, including £30.2m to scale up workforce capabilities, and a further £44.9m in various Information Technology (IT) and Operational Technology (OT) projects that will underpin their ability to deliver the primary DSO roles.

They propose to use a 'Flexibility First' commitment to avoid the need for reinforcement. In addition, they plan to grow flexible connections to 3.7GW of capacity to avoid £417.6m of reinforcement cost.

The DSO plan refers to many of the ENA Open Networks project initiatives, including:

- Planning & network development – DFES will be improved in collaboration with other DNOs – aiming to introduce new tools to improve quality of data. Planning to have an exchange for data sharing; network capacity portal to be introduced; annual DNOA to be published
- Network operation – ENA DSO roadmap to be completed late 2023 to facilitate data exchange and system visibility; future flexibility statement has been produced. LV monitoring is being introduced
- Market development – adopting common ENA processes

Overall, the SSEN digitalisation strategy is set out at a high level but it's difficult to assess how benefits are calculated e.g. ANM and gain confidence about delivery. The scale up in metering is welcomed.

Similarly, the DSO action plan appears relatively high level with most delivery dates to be confirmed, and the delivery of flexibility targets are not well evidenced.

We would welcome a clear explanation of proposed DSO costs (including enabling system systems, metering, ANM, etc) together with the associated benefits. Cost increases from ED-1 should be clearly justified.

DSO CVP

The following table sets out the proposed SSEN DSO CVPs. We think there is merit in the local and community flexibility market facilitation, which could perhaps be combined with the similar proposal for whole system. However, the detail is unclear. We would welcome a clear explanation of what is planned and when, together with details of what the money is being spent on and what the benefits may be.

CVPs				
Energy Efficiency accelerator for smarter networks	CVP	We will proactively work with partners to identify and implement energy efficiency measures across our customer base.	£22.9m	Stakeholders have asked that we support all our customers in the energy transition. **Benefits:** £26.6m net customer benefit - Reduced need for reinforcement, lower customer bills, support for the fair distribution of benefits from smart technology, wider societal benefits (eg carbon savings).
Local and community flexibility market stimulation	CVP	We will partner with aggregators and Energy Suppliers to actively target recruitment of flexibility with a focus on fuel poor customers and those in vulnerable circumstances.	To be included in final plan	Our approach will actively promote a localised, balanced energy system, ecosystem benefits. **Benefits:** Communities empowered to participate in flexibility markets, benefiting from the energy system transition.

7. Whole system proposed strategy and ambition

We are seeking to understand the costs and benefits of whole system initiatives that companies plan to undertake in coordination with stakeholders across electricity and other sectors. We are seeking to understand how this exceeds business as usual benefits.

SSEN's plan focuses on three key steps to achieving their long term vision for whole systems

- Reflecting on progress and lessons learned
- Reviewing internal processes to embed and promote Whole Systems solution delivery
- Embedding Whole Systems thinking into decision making

SSEN propose to establish a temporary Whole Systems Change Management team to take ownership of the change management required to achieve this plan and embed it into BAU by the end of ED2.

We welcome SSEN's proposals to work more closely with Local Authorities and community groups to help them transition to net zero. However, there is little evidence that the action plan developed for the Whole Systems goes significantly beyond the electricity system. While we appreciate that this is 'work in progress', we would hope to see further development of the transition plan in the final Business Plan.

Overall, while we welcome SSEN's whole system ambition and approach, we are concerned that this may have a primarily inward focus and additional benefits above business as usual appear uncertain.

Whole systems CVP

SSEN propose the following CVPs for whole systems.

CVP	**Purpose**	**Value to consumer**
Embedded Whole Systems Support Services for Local Authorities	We will provide support to local authorities and community groups by applying our expertise to facilitate the optimisation of the electricity network, delivery of whole system opportunities and net zero transition.	11.5

We think the proposal to provide local authorities with embedded support to help them optimise the electricity network has merit, and should be developed further for the final plan, demonstrating what the costs and potential benefits might be. As described in the previous section, this CVP could potentially include support for these groups to understand how they could participate in flexibility markets.