

# CONNECTIONS COSTS AND INDUSTRIAL AND COMMERCIAL DEMAND

Evidence from 27 sessions across the connection ecosystem -  
ADE: Demand, August 2026

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This report is released with an accompanying condensed and illustrated headline report for stakeholders and policy makers.

Find it here: [ADE: Demand Connections Costs - Final Headline Report](#)

## **Executive Summary**

### **The problem is early cost confidence**

Industrial and commercial businesses cannot obtain a credible estimate of connection cost early enough to support an investment decision. That is the specific failure documented by this study. High connection prices matter, but the evidence points to a prior problem: businesses often cannot establish a usable cost range before they commit money and staff time. When a formal figure arrives, they may still struggle to understand which elements relate to dedicated assets, which costs arise elsewhere in the network, and which dependencies sit with the transmission system. For a board considering electrification, the timing of that information changes the financial meaning of the quote.

Ofgem's Access SCR reduced the reinforcement costs borne upfront by most demand customers. That reform does not remove uncertainty over sole-use works, high-cost exceptions, transmission-linked costs or delivery dates. The remaining problem is whether a business can understand its likely exposure early enough to act on it.

### **Industrial investment decisions cannot wait indefinitely**

Many industrial electrification decisions are tied to physical asset-replacement dates. A furnace, boiler or other process asset may remain in service for twenty years or more. If the electricity connection cannot be costed and delivered within the replacement window, the electrification option can pause before a formal application is ever made. The fossil-fuel replacement can then remain the practical option available at the point when the site has to invest.

The evidence supports a narrower point: projects can fall away before the stages the system currently measures, without any evidence of deliberate deterrence by the connections process.

### **What we studied**

The study draws on 27 research sessions conducted in the first half of 2026. Participants included distribution network operators, NESO, Ofgem, government policy teams, trade bodies, connections specialists, intermediaries and industrial and commercial customers.

The report presents six composite case studies and three shorter vignettes. Their purpose is to show recurring mechanisms in the evidence. They do not estimate prevalence across all businesses. Participant-reported figures are approximate and have not been independently audited.

### **What the research found**

Cost information arrives too late. Published charging methodologies explain the formal rules, but they do not normally give a larger I&C customer a site-specific cost range that can be used at the point when an investment case is being assembled. Formal application remains the main route to a firm answer. By then the customer may have paid fees,

committed internal resource and developed the project far enough to make an application meaningful.

There is no public, comparable benchmark for larger I&C connection quotes across DNO regions. DNOs publish charging methodologies, indicative prices for some connection types and a growing range of network data. That material is useful. It does not allow a business holding a large project-specific quote to compare the figure, its component costs or its delivery assumptions with similar projects elsewhere. The same gap limits Ofgem's and government's ability to compare outcomes.

Transmission risk can become visible after the customer has already committed to the distribution process. The evidence records demand projects where upstream assessment changed the expected cost or date after the initial DNO offer. The size of project that triggers this interaction varies with local network conditions and the relevant grid supply point. Customers therefore experience one connection while responsibility for assessment and delivery may be split between the DNO, the transmission owner and NESO.

Delay is part of the cost faced by the business. Staff time, adviser fees and technical work continue while dates move, and designs may need to be revisited. The evidence also records the opportunity cost created when a connection date misses an asset-renewal or capital-allocation window. A price that appears manageable at one date may support a very different investment decision if delivery moves several years.

Deterred demand is largely missing from official data. A business may need cost and timing information before it can mature a project, yet the most reliable information is usually obtained through a formal application that itself requires project maturity. Several participants described projects pausing at this earlier stage. Because these projects never enter the queue, they are absent from queue statistics and can also be missed by network planning. A smaller recorded queue can therefore coexist with industrial demand that has not reached application.

### **The current system also contains practices that work**

The evidence records useful practice within the existing framework. Early conversations with network operators helped customers test capacity options and avoid unsuitable applications. Where projects crossed organisational boundaries, named contacts improved communication.

Some customers also benefited from flexible, phased and self-build routes, although their suitability depends on the customer's operations and the constraint being addressed. Access to this support is inconsistent.

The case evidence shows why this matters for investment. One industrial composite received an indicative proposition of around £10 million for roughly two kilometres of new network with a delivery period of about five years. The figure was difficult for the business

to test because it lacked a comparable benchmark and sufficient decomposition of the assumptions behind it.

Other evidence described portfolio investment decisions where connection feasibility and timing influenced which sites were prioritised. The evidence supports a qualified conclusion: connection uncertainty can materially alter the business case alongside electricity prices, capital costs and the timing of asset replacement. It does not establish connection uncertainty as the sole determinant of where investment goes.

### **Earlier cost information should be the starting point for reform**

The strongest intervention is earlier cost confidence. DNOs should provide decision-grade indicative information before formal commitment, based on a minimum level of information from the customer. That response should set out an indicative cost range, the assumptions behind it, known network constraints and the factors most likely to change the figure.

The early estimate would remain indicative, with contractual certainty reserved for the formal offer. Its job is to give a business enough information to decide whether the project should mature to the next stage. The ED3 framework should support this pre-application function and measure whether major demand customers can obtain useful early information.

Quote transparency also needs a common minimum standard. Ofgem should require larger connection offers to show the reasoning behind the figure, including the relevant treatment of sole-use assets, shared works, contestable and non-contestable elements, and any upstream dependencies. Where an allocation or apportionment calculation applies, the customer should be able to see it.

Ofgem should also require publication of anonymised benchmark data on larger I&C connection quotes, component costs and delivery timelines so that customers and the regulator can compare outcomes across regions.

### **Demand needs to become visible before it enters the queue**

Uncertain industrial demand needs a route into planning before a formal application. NESO's work on demand signalling provides the obvious mechanism. A demand register should allow businesses to submit ranges and non-binding estimates without reserving capacity or entering the connection queue, while making clear that formal applications remain the stronger evidence of committed demand.

That information should inform Regional Energy Strategic Plans and DNO investment planning. DESNZ and Ofgem should also measure projects that pause before application, because queue data alone cannot show the demand that the current process never receives.

Connections that span DNO, transmission-owner and NESO processes need clearer accountability. Upstream dependencies should be disclosed before acceptance where they are known, and customers should be told which dates remain provisional. When a

connection date changes, one named contact should be able to explain the responsible process, the reason for the change and the next decision point. Service standards should reflect the experience of the customer across institutional boundaries.

### **Industrial policy has a part to play**

Government support for industrial electrification should recognise that upfront connection costs and asset-replacement timing can determine whether an otherwise credible project proceeds.

Industrial electrification and data-centre demand should remain distinct in policy analysis where their economic purpose and project characteristics differ. Network planning still needs to account for both where they compete for, or can share, the same infrastructure.

### **The test for the reforms now underway**

Ofgem's connections work, ED3, Regional Energy Strategic Plans and work on demand signalling will shape what information an industrial customer can obtain before committing to a connection.

The evidence in this report points to a practical test for those reforms: can a business establish a credible range for cost and timing early enough to make an investment decision, understand what sits behind that range, and become visible to planners before it is ready to join the formal queue?

At present, too many cannot.

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## 1 The issue in brief

When an industrial site decides whether to electrify, the decision is usually anchored to a physical asset. A furnace or a boiler reaches the end of its life, and the operator chooses between a like-for-like fossil replacement and an electrified alternative. The choice binds the site for the life of the new asset, often twenty years or more. The grid connection sits on the critical path of that choice, and for many sites it is the one element of the business case that cannot be pinned down in time.

This report is about a specific failure. Industrial and commercial users cannot find out, early enough to make a credible investment decision, what a new or upgraded electricity connection is likely to cost them. The problem is commonly described as high prices. The evidence gathered for this study points somewhere more precise. Businesses cannot get a believable early estimate of what they will pay. When a figure does arrive, they often cannot see which parts of it are theirs alone, which are shared, and which have come down from the transmission network. By the time the picture clarifies, the money and staff time have already been committed. The policy problem is cost confidence, cost attribution and the timing of information. Most of the remedy is better information, provided earlier with its assumptions stated.

The uncertainty shows up at different points in different forms. A site trying to build a business case may find no route to an indicative figure short of a formal application, because connection costs do not rise smoothly with capacity. They jump at technical thresholds, a voltage step, a transformer, a reinforcement trigger, that only the network operator's models can see. One connections specialist interviewed for this study put the consequence plainly: on a large project, a £2 million quote "could just as likely be £4 million when you finish". A quote, when it arrives, may present a headline figure without the apportionment calculation behind it, so the customer cannot check whether their share of reinforcement or shared assets was derived correctly. A distribution-level project of a few megawatts can trigger a transmission impact assessment, a modification fee and a place in a different queue, none of which the customer anticipated when they approached their local network operator. A business that connects first may pay for capacity that later users benefit from. Around all of this sits a layer of internal cost that never appears in any quote: staff time, adviser fees, repeated technical studies, and investment windows that close while dates move.

The deepest version of the problem is the threshold itself. At present, the main way to get a firm answer is to submit a formal application. But an application costs money, consumes internal resource and, once accepted, can reserve capacity the business is not ready to use. Businesses therefore face an unattractive choice between committing before their project is commercially ready and staying invisible to the system entirely. Many choose invisibility. Interview participants from government, trade bodies and the research community all made the same observation: projects that die at an informal early conversation never

appear in any queue or dataset, so the formal connection statistics understate how much industrial demand is being suppressed.

Participants described connection feasibility changing portfolio priorities. In one consultancy example, a global manufacturer prioritised a German electrification site over similar UK sites mainly because UK connection timing was uncertain. Other multi-site work showed the best technical electrification site losing priority when its connection was materially more expensive. The opacity reaches further up the system than might be expected. One government policy participant described connection charging as opaque even to the officials working on it, which leaves a manufacturer weighing a furnace replacement with little chance of doing better. Distribution network operators, for their part, described a divided customer base: experienced applicants can self-serve, while first-time decarbonisation customers, often the manufacturers government most wants to electrify, need translation and options work before they can frame a request. The businesses least equipped to carry uncertainty are the most exposed to it.

None of this starts from a blank page. In March 2026, ADE: Demand published its first position paper on connections and industrial and commercial demand. That publication identified distribution-level connections for I&C users as a gap in a reform agenda that had concentrated on transmission-level generation. It argued that published charging methodologies and open-data tools, useful as they are, do not give a prospective customer a comparable picture of actual connection quotes, and it identified the absence of a public, regionally comparable dataset of actual connection costs, queue positions and typical timelines as a constraint on customer benchmarking and regulatory oversight. It also committed ADE: Demand to a case-study-led research programme to test those claims against real experience. This report is the output of that programme. The earlier publication established the policy gap. The sections that follow show what the case evidence reveals about it.

The timing matters because the surrounding system is being redesigned now. The connections process is under end-to-end reform. ED3 will set the next distribution price control and the service standards that come with it. Regional Energy Strategic Plans are standing up, and they will only be as good as the demand information that reaches them. NESO is developing routes for demand signalling ahead of formal applications. Demand itself is growing from industrial electrification and from data centres, which this report treats as a distinct category rather than a proxy for industrial need. Decisions taken in these processes over the next two years will determine what information an industrial customer can get, and when, for the rest of the decade. The risk is that reform concentrates on the stages of the process that are already visible and measured, such as queue management and quote turnaround, while the early stage, where electrification decisions are made or quietly abandoned, stays untouched.

What follows is grounded in empirical evidence. The study behind this report gathered evidence across the whole connection ecosystem: distribution network operators, the

regulator, government policy teams, trade bodies, connections consultancies and intermediaries, industrial and commercial customers, and data-centre developers. That evidence was coded and cross-checked, and it is presented in this report through composite, anonymised case studies. The cases carry the report. Before they appear, the box below names the specific fears that recur across them, because the single clearest finding of this study is that businesses are not frightened of one big number. They are frightened of particular, identifiable things, and each of those things has a policy owner.

The report is organised so that the reader meets those businesses quickly. A short review of the existing literature comes next, because the case for new evidence rests on what the published material cannot show. A brief method note follows. The case studies then carry the central sections: composite accounts of real connection experiences, followed by a synthesis of what they reveal, and recommendations addressed to the actors able to act on them.

A note on scope. This is a report about connection costs: what they are, who they fall on, and when they become known. It is not a general connections reform report, and it does not cover queue management, service quality or network planning except where they change what a customer pays or what a customer can know. Timelines appear throughout, but only because delay creates cost and because a date that cannot be trusted undermines a cost figure that depends on it.

## 1.1 What businesses are afraid of

Before entering a formal process, a business needs to know what it is likely to pay, which part of the system is driving that cost, how firm the figure is, and what it can decide before committing. The fears below are the ways those questions currently go unanswered.

- **Unknown total cost.** No credible estimate is available before the business has already committed time and money.
- **Reinforcement and shared-asset allocation.** Quotes often omit the apportionment calculation, so the customer cannot check or challenge their share.
- **Sole-use treatment.** A large connection can be classed as the sole user of assets that later customers will share.
- **Transmission pass-through.** Costs and delays that originate upstream arrive late, unexplained and outside the distribution network operator's control.
- **First mover exposure.** Whoever connects first may pay for capacity that later users benefit from.
- **Ongoing network charges.** Where relevant, uncertainty about future use-of-system charge exposure becomes tangled with the one-off connection cost and inflates the perceived risk.

- **Internal costs of delay.** Staff time, adviser fees and repeated technical studies accumulate while dates move, and investment windows close.
- **Entering the process too early.** The only route to a firm answer is a formal application, which commits resource and can reserve capacity before the project is commercially ready.

## 2 What is already known and what remains unclear

### 2.1 Industrial electrification raises the stakes at distribution level

Most industrial and commercial sites connect to the distribution network, and the literature indicates that this is where the pressure will build. Modelling by the Aldersgate Group projects UK industrial electricity demand rising by 78% by 2050 under a high-electrification pathway, with distribution-level constraints emerging from 2030 and around three-quarters of large industrial sites facing access constraints by 2050. Most of those constrained sites are dispersed rather than located in industrial clusters, which means they cannot rely on cluster-focused infrastructure policy (Gailani, A *et al.*, 2025). Sector studies show the same dynamics at ground level. A grid connection assessment of UK paper mills estimated some 758 MW of new connection capacity needed across 19 mills at a cost of roughly £224 million, and found that feasibility hinged on local network headroom: around a third of the mills could connect at existing substations, while others required higher-voltage connections, substantial reinforcement or transmission-level solutions (Marquand, 2022). A preliminary IDRIC survey of 26 industrial respondents reported connection and upgrade costs from around £100,000 to £75 million, and delays of 2 to 12 years, with some offers reaching into the 2030s (IDRIC, 2023).

These sources establish scale and variability. What they cannot show is how an individual business experiences that variability when it has to make a decision.

### 2.2 Distribution-level demand is distinct from transmission reform

The recent wave of connections reform grew out of the transmission-level generation queue. The Connections Action Plan and the queue reforms that followed it target speculative applications, project milestones and readiness, problems characteristic of a long queue of competing generation projects (DESNZ, 2023). Industrial and commercial demand customers at distribution level face a different problem. Their difficulty is rarely a decade-long queue of rivals. It is that they cannot establish their likely cost exposure before applying, and the reforms built for the transmission queue do not address that. ADE: Demand's March 2026 publication identified this distribution-level gap and argued that cost transparency for demand customers had remained under-addressed while attention concentrated upstream (Fay, Ocean, 2026). Where the two levels meet, the effects are concrete: a distribution-connected demand project can inherit transmission-driven costs and delays through impact assessments and upstream constraints, as both the regulatory framework and regional evidence show (Ofgem, 2022; Ricketts, 2025)

### **2.3 What is known about cost drivers**

The formal drivers of connection cost are well documented. Charging statements and Ofgem's connections policy guidance set out the main variables: the capacity requested, the voltage level of connection, the distance from the existing network and the assets needed to bridge it, available network headroom, whether reinforcement is triggered, civil works, and land rights (Ofgem, 2014; National Grid, 2025). Charges are built on a minimum scheme principle, meaning the customer pays on the basis of the cheapest technically acceptable design. The literature is also clear that cost does not scale smoothly with capacity: a request that fits within existing headroom can be cheap, while a marginally larger one that triggers a voltage step or reinforcement can be far more expensive (Marquand, 2022). Knowing the list of drivers, however, tells a customer very little about their own site, because the decisive inputs, headroom and reinforcement need, sit inside the network operator's models.

### **2.4 What charging methodologies and regulations explain**

Every distribution network operator publishes a statement of its connection charging methodology. These documents explain how quotes are constructed: the boundary between sole-use extension assets and shared reinforcement, apportionment rules for shared assets, the split between contestable and non-contestable works, and assessment and design fees (National Grid, 2025). The second-comer regulations govern what happens when a later customer uses assets an earlier one paid for, giving the first mover a partial reimbursement route with a ten-year window (*The Electricity (Connection Charges) Regulations 2017*, 2017; ENA, 2024). This body of material is authoritative on the rules. It contains no GB-wide dataset of larger I&C quote outcomes. A methodology statement explains how a charge would be derived after assessment; it does not tell a prospective customer what a connection like theirs actually cost anyone else, and industry guidance itself notes that reimbursement rules for reinforcement narrowed after the Access reforms, concentrating second-comer exposure on shared extension assets (ENA, 2024).

### **2.5 What the Access SCR changed for demand users**

Ofgem's Access and Forward-Looking Charges Significant Code Review, implemented from April 2023, changed the charging boundary for demand connections. Demand customers now generally pay for their sole-use extension assets only, with network reinforcement funded through use-of-system charges rather than upfront quotes, subject to a high-cost cap for unusually expensive reinforcement and a speculative-development assessment that can return full reinforcement costs to an applicant who cannot evidence their project (Ofgem, 2022; Scottish and Southern Electricity Networks, 2024). This was a material improvement in upfront exposure for many demand projects. It did not resolve the confidence problem. Analysis of the final decision suggests the principal uncertainty for I&C demand users has shifted rather than disappeared: it now sits in whether a project qualifies under the high-cost or speculative criteria, and in transmission-attributable cost elements that remain outside the shallow boundary (Ofgem, 2022). A customer can therefore face

the old question in a new form: not “how much reinforcement will I pay for?” but “will my project be the exception that pays?”

## **2.6 What published charging information shows**

A structured scan of published connection information from all six GB distribution network groups, conducted for this study, confirms two things. The formal charging rules are highly standardised, and the cost a specific customer will face stays out of view until late in the process.

Every group applies the same Common Connection Charging Methodology set out in the Distribution Connection and Use of System Agreement. The high-cost threshold is £200 per kW for generation and £1,720 per kVA for demand. For demand connections, the DNO funds reinforcement up to the threshold and the customer contributes only reinforcement costs above it. The Cost Apportionment Factor applies to generation reinforcement under the generation threshold, not to demand reinforcement. Where connection charges exceed £20,000, the offer carries a cost breakdown. These common rules were verified against primary published sources.

Published pricing is a different matter. What each group discloses about likely cost varies, and none of it amounts to a comparable record of real quotes. National Grid Electricity Distribution, UK Power Networks and Northern Powergrid publish indicative price tables. Above small low-voltage jobs these resolve to “price on application” or a figure “provided after application review”. Northern Powergrid goes further than its peers by publishing average as well as starting prices, which shows how far a typical case sits above the headline figure: its typical small business connection starts at £1,900 but averages £18,100, and its typical large business connection starts at £2,700 but averages £78,500. SP Energy Networks and SSEN publish no price table, offering budget estimates and optioneering instead, with SSEN charging between £248 and £8,060 plus VAT for a feasibility study.

The pattern holds across all six groups. A prospective customer can read the rules that govern a charge without being able to see a comparable record of larger I&C demand quotes across regions. NGED publishes a limited historical dataset for high-volume, low-voltage on-street EV connections, which is useful but not comparable with the HV and EHV industrial connections examined here. For larger I&C demand connections, the scan found no public, regionally comparable dataset of actual issued quotes. This is the gap the case study evidence addresses. The methodology is legible on paper. The number that decides an investment becomes visible only once a business has committed to a formal application. An annex at the end of this report sets out the published charging information by network group.

## **2.7 Why published rules do not amount to early cost confidence**

Taken together, the methodologies, regulations and the post-SCR regime mean a well-advised customer can understand in principle how a charge is calculated. The literature offers nothing that lets them judge, before committing, whether a specific offer is

reasonable. Three published resources fall short in specific ways. Capacity and headroom maps give a view of where the network is constrained, but sector evidence shows that map-level headroom is an unreliable basis for a firm decision where a large request can dominate a substation and trigger upstream works that no map displays (Marquand, 2022). Open-data programmes and self-service tools are expanding, and distribution network operator reporting shows genuine investment in them, but they describe the network rather than the composition of quotes (UK Power Networks, 2024). And industry responses to Ofgem's engagement incentives have flagged that the accuracy and consistency of pre-application datasets varies across operators (Renewable Connections Developments Limited, 2022).

The measurement regime reinforces the gap. Ofgem's Major Connections Incentive requires distribution network operators to report customer satisfaction, time to quote and time to connect, and it sets baseline expectations for quote breakdowns (Ofgem, 2024). What operators publish under it is service performance: days to quote, satisfaction scores, initiative progress (Electricity North West, 2025; UK Power Networks, 2025). No equivalent GB-wide publication exists for larger I&C connection cost. There is no public, comparable dataset of actual larger I&C demand connection quotes, their component costs, or how similar requests were priced in different regions, a gap ADE: Demand's earlier publication identified as a constraint on both customer benchmarking and regulatory oversight (Fay, Ocean, 2026). The pattern is long-standing. As far back as 2013, a review of community energy connections documented wide regional variability in connection costs and limited pre-application optioneering, and proposed standardised cost breakdowns as a remedy (Simonds and Hall, 2013). A decade later, no comparable GB-wide dataset exists for larger I&C demand connections.

The concentration on timeliness has a history. The RIIO-ED1 price control sharpened incentives on quote and connection times for smaller connections and required strategic engagement on larger ones, and successive reforms have kept speed and service quality as the measured dimensions of connections performance (Ofgem, 2014, 2024). Speed can be measured from data distribution network operators already hold. Early cost confidence has no equivalent metric, so no operator is rewarded or penalised on it. The data problem runs deeper than incentive design: Ofgem's own impact assessment for the Access reforms recorded that limitations in historic data constrained its analysis of how the existing high-cost cap had affected applications, and the Connections Action Plan acknowledged material unknowns at the transmission and distribution interface, proposing a unified data view to address them (Renewable Connections Developments Limited, 2022; DESNZ, 2024).

Timelines belong in this picture only because they corrode cost certainty. The IDRIC survey's reported delays of 2 to 12 years matter for a cost report because a quote attached to a date that moves is a different financial proposition from the same quote attached to a firm one, and because every year of slippage adds internal cost that no quote captures

(IDRIC, 2023). The literature documents the delays. It does not document what they cost the businesses waiting.

## **2.8 The gap this report fills**

The literature reviewed here can explain the formal charging framework and the broad drivers of connection cost. What it cannot do is show how industrial and commercial customers experience cost uncertainty inside real investment decisions: what they knew at the point of decision, what they could not find out, which perceived risks changed their behaviour, and how they read the costs attributed to them. Published sources describe rules and service metrics; none of them contains the decision. Case-study evidence suits this problem for a practical reason, made by government participants in this study: industrial demand connections are still comparatively rare events, so how the charging regime behaves in practice is better observed through individual cases than through statistics that do not yet exist. This report addresses that gap through case-study evidence on customer decision points, perceived risks and cost attribution concerns. The next section describes how that evidence was gathered, and the case studies follow immediately after it.

## **3 Method and evidence base**

The findings in this report draw on 27 research sessions conducted in the first half of 2026, comprising interviews, stakeholder meetings and two asynchronous documentary case studies. Sessions were structured around five research questions: how distribution-level connection costs are calculated; the connection process from feasibility to energisation as customers experience it; what is and is not standardised across network regions; how cost and timeline uncertainty affect investment decisions; and what practical reforms would improve transparency, predictability and fairness. From these sessions, 937 evidence items were extracted and coded against a 16-code framework, and the coded items were cross-checked into the analytical themes that structure Sections 4 and 5.

The evidence base covers the entire connection ecosystem. It includes six GB distribution network operators, the system operator, the regulator, government policy makers, sector trade bodies, consultancies, intermediaries, industrial and commercial customers including manufacturing and strategic infrastructure operators, data-centre developers, and an energy research centre. The research also examined how distribution assessment, transmission assessment and delivery interact. Sections 4 and 5 set out the findings.

Three features of the evidence shape how it should be read. Consultancies and trade bodies frequently speak for anonymised clients or members, which widens sector coverage but means some cost detail is second-hand and commercially guarded. The evidence on deterred demand is indirect by nature, because a project abandoned before application leaves no record to examine; the report treats suppressed demand as strongly indicated rather than measured. And the strongest evidence is case based rather than statistical. That

is a fit to the problem rather than a concession: as a government participant observed, industrial demand connections are still comparatively rare events, so how the charging regime behaves in practice is better observed through real cases than through statistics that do not yet exist.

The six case studies in Section 4 are composite, anonymised archetypes. Each is anchored in one or more real connection accounts and widened with cross-cutting material from other sessions. They are written to reduce identification risk and to carry recurring mechanisms rather than one participant's full circumstances. Three shorter vignettes carry single mechanisms the same way. Where a case rests mainly on a single account, the text says so. Figures are participant-reported and approximate; they are presented as evidence of where risk concentrates, not as audited costs, and where a figure could identify a site it appears as a range or a rounded order of magnitude.

Organisations are described by role or sector, with identifying detail removed, in line with participant consent.

Data-centre evidence is included but held apart wherever it matters. A government participant asked that the analysis not blend data centres with industrial manufacturing, describing them as two different strategies for government with different project characteristics. Data-centre cases expose the transmission interface, queue pressure and date-driven investment with unusual clarity, and the report uses them for that. It does not treat them as representative of industrial electrification demand.

The limitations are those of a qualitative study of a system in flux. The sample is structured rather than representative; the figures show where cost and timeline risk concentrates, not a cost distribution; and connections policy was moving throughout the fieldwork, so the policy mapping in Section 7 reflects the position at the time of writing. None of these limits the central findings, which rest on patterns recurring independently across participants with no reason to coordinate their accounts. The published-information scan described in Section 2 is baseline context rather than primary evidence: its purpose is to establish what a customer can and cannot learn before applying, and every figure in it is linked to a primary published source.

## **4 Case studies: connection cost uncertainty in practice**

The findings in this Section and the next draw on 27 research sessions with distribution network operators, the regulator, government policy officials, trade bodies, connections consultancies and intermediaries, and industrial, commercial and data-centre customers. The coded evidence base behind them runs to 937 evidence items. Section 3 sets out the method; this section sets out what the evidence, taken together, says.

## 4.1 What the evidence shows

The first thing it says is that there is no single connections problem. Participants described four distinct problems, with different mechanisms and different fixes. Reform debates tend to treat them as one, which helps explain why single-instrument reforms keep disappointing.

### 1. Cost variability

Near-identical sites can receive very different quotes. Some of the variation is legitimate engineering: point of connection, route complexity, local headroom and network condition all move the number for sound reasons. Some of it is procedural inconsistency, and the evidence shows that inconsistency inside a single distribution network operator can be as sharp as inconsistency between operators. One developer received two contradictory answers to the same constraint question from the same network operator, corrected only when an experienced area planner intervened.

### 2. The translation gap between published methodology and actual quotes

Charging methodologies are public documents. Yet participants who handle connection quotes at volume told the study that the rates on real quotes cannot be reliably reconciled with the published rates, and that base prices form in ways that are not a clear process. A quote can be fully itemised and still impossible to interrogate. One customer put the experience plainly: "I don't think I understand how connection costs are calculated at all. I think it is a black box, and a number comes out the other end." A distribution network operator participant, asked about the line items in that organisation's own offers, said: "It's great having all these line items of cost, but I don't really know what they mean."

The gap between published methodology and actual quote is structural as well as presentational. Distribution network operators are required to offer the minimum-cost technically acceptable scheme at the quote stage. Evidence from a major distribution and transmission licence holder confirmed that the minimum-cost design is not always the same as the most deliverable solution: design assumptions made at quote stage can be revised when the work moves to the delivery team, which is one mechanism by which the gap between a quoted figure and the final cost widens. The effect compounds the already-limited ability of customers to audit a methodology against the price they are offered.

### 3. The character of the connection process itself

Customers can usually name every stage they are in. What they cannot obtain is a reason or a date: why the minimum scheme was chosen, or what assumption is driving the reinforcement element. When a dependent upstream decision will land, nobody can say. The process is procedurally legible and practically opaque.

### 4. The fourth is the handoff between institutions

Where a distribution connection touches transmission infrastructure or system-operator processes, uncertainty multiplies. The structure is a tri-party one. The distribution network operator retains the customer relationship and delivers the

distribution works. The system operator coordinates transmission impact assessment, while the transmission owner designs and delivers any required transmission-level works. From the customer's perspective, this structure is largely invisible. They experience a distribution offer that is conditional on a transmission assessment they had not anticipated, issued through an institution they may not have contacted. System-operator evidence collected for this study confirmed that a distribution offer may leave the customer without a complete cost and timeline picture until the transmission assessment is finished. The most damaging delays in the evidence base trace back to these seams: offers accepted and paid for before transmission impact is assessed, gate decisions with no published dates, and energisation dates moving by years without explanation. The regulator's view deserves equal weight. In its assessment, interface friction explains months of delay, while genuine constraint and delivery limits account for much of the longer slippage. The cases present both readings.

Across all four problems, one message recurred more consistently than any other, and it concerned time. "Often the cost is not the issue. It's the delivery timescales that are the main problem," a connections consultant told the study. A trade body agreed: "Probably the bigger issue is still timing." The same consultant described asking nineteen times, across twelve people, what was driving a single 2037 connection date, without ever receiving an answer.

This report is about connection costs, and the time finding belongs in it, because businesses experience time and cost as a single quantity. Delay is a cost: staff time, consultant spend, design work that ages and must be redone, board patience, missed investment windows. A quoted price that cannot be trusted to hold across a five-year delivery period is not a price a board can approve. And for industrial sites, connection timelines compete with fixed asset-renewal windows; an offer that arrives after the window closes has no value at any price. The cases that follow show cost uncertainty and timeline uncertainty compounding each other at exactly the moments when investment decisions are made.

The evidence also shows what businesses do in response. Some never enter the process at all, deterred by informal signals long before a formal application, which means the demand they represent appears in no queue statistic. Others work around the network with on-site generation, private wire or optimisation within an existing connection. The rest proceed and absorb the uncertainty as risk premium, contingency and delay. Each response carries a system cost that current reform metrics do not count.

The six case studies below are composite, anonymised archetypes built from this evidence. Each is anchored in one or more real connection accounts and widened with cross-cutting material from other sessions. They are written to reduce identification risk and to carry recurring patterns rather than one participant's full circumstances. Figures are participant-reported and approximate and are presented as evidence of where risk concentrates rather

than as audited costs. Three shorter vignettes sit between the cases. The set also records what worked: the evidence contains real examples of good service, and the report is stronger for naming them.

## 4.2 Case Studies and Vignettes

### 4.2.1 Case study 1: The manufacturer deterred before the first form

#### Profile

- **Sector:** energy-intensive manufacturing, a dispersed site outside the main industrial clusters.
- **Connection need:** a step-change import capacity increase to electrify process heat at the next plant rebuild.
- **What it knew:** electrification is technically attractive; the rebuild window is fixed by the life of the existing asset.
- **Decision at stake:** whether the next asset-renewal cycle is electric or gas. The choice locks in for the life of the new plant.

The need emerges years before any application could sensibly be made. The site's main process asset is approaching the end of its life, and the board has asked the energy manager to test whether the replacement can be electric. The technical case is respectable: in the glass sector, participants described electric melting as the most efficient way to melt glass, viable all-electric below roughly 250 tonnes a day.

There is no formal application, because the business is not ready to make one. It does not yet know its final capacity requirement, and a formal application would commit fees and reserve capacity against a project with no approved business case. So the energy manager explores informally: liaison meetings with the network operator, a high-level enquiry route that gives a yes or no answer subject to design, conversations through the trade body. One large site in the evidence base had last made a formal request for connection information around a decade ago, with only informal exploration since.

What comes back is discouraging without being a refusal. A trade body for energy-intensive industry described members receiving informal signals that delivery could be several years away and said such responses can mean potential applicants never enter the formal process at all. For this site, the indicated timeline lands on the wrong side of the rebuild window. Sector evidence was clear about the consequence: if the connection takes eight years and equipment expires in two, the timing mismatch can force a fossil-fuel replacement regardless of the connection price.

Cost information is no better. The site cannot obtain even an indicative range without entering the process. What it has instead is a sector rumour mill, in which connection horror stories of no availability, long delays and large upgrade costs circulate through member

networks and stand in for data. One comparable site's earlier study had put combined electrification costs above £100 million once network reinforcement and customer-side plant were added together, a figure the business could not decompose into its network and non-network parts. With electricity discussed internally at around five times the cost of gas per unit, the energy manager cannot build a case the board could approve.

The project pauses without ever formally existing. The trade body described dispersed sites as “sat on the fence”, waiting for movement on the electricity-gas price differential and on capital support. Some members examine workarounds that avoid the connection process altogether: private-wire supply, through-the-fence generation, or in one perverse example, an on-site electrolyser burning hydrogen less efficiently than direct electrification would, because a funded business model exists for the electrolyser and none exists for the connection.

The wider consequence is statistical invisibility. Because the project never entered the queue, no distribution network operator, regulator or government dataset records it. A government policy participant described the blind spot directly: industry is not applying for grid connections at anything like the scale net zero requires, so the system cannot learn from applications that are never made.

**What worked:** regular informal liaison meetings surfaced potential capacity availability early, and participants valued them; the high-level enquiry route exists and costs little; trade-body networks supplied some second-hand market intelligence.

**What broke down:** no credible pre-application cost or capacity signal; informal multi-year timeline indications, delivered without options or explanation, acted as a de facto refusal; the deterred project left no trace, so its demand is invisible to network planners, Ofgem and DESNZ alike.

### Policy implications

1. **Measure deterred demand:** Queue statistics cannot show the scale of suppressed industrial demand; Ofgem and DESNZ should commission systematic evidence on projects abandoned or paused before formal application.
2. **Mandate decision-grade pre-application information:** Distribution network operators should be required to provide indicative cost ranges and constraint information at enquiry stage, with stated assumptions and confidence levels.
3. **Create a non-committal demand signalling route,** so a site can lodge a rough, non-binding electrification plan without forcing a premature application.
4. **Recognise renewal windows in electrification support design:** A connection offer that arrives after the asset-renewal window closes has no value to the customer.

#### 4.2.2 Case study 2: Two kilometres, ten million pounds, five years

##### Profile

- **Sector:** energy-intensive manufacturing within a global group.
- **Connection need:** a new or substantially upgraded import connection for an all-electric process, requiring roughly 2 km of new network.
- **What it knew:** an early indication of around £10 million and about five years to deliver.
- **Decision at stake:** a group-level capital allocation choice between electrifying the UK site, electrifying a sister site overseas, or reinvesting in gas.

This business gets further than the site in Case 1 (4.2.1). It is large enough to resource a serious feasibility exercise, and its group is actively comparing decarbonisation investments across countries. It obtains a genuine early indication of the connection requirement: around 2 km of connecting infrastructure, an expected cost of about £10 million, an expected timeline of about five years. Participants noted that 2 km is not a long distance; the figure reflects works, reinforcement exposure and route, not extreme geography.

The figure arrives with little decomposition. The business cannot see how much is sole-use assets, how much is reinforcement, what triggered any reinforcement element, which works are contestable, or what assumptions about route and civils sit underneath. Distribution-operator-side evidence explains why the number resists interrogation from outside: quotes are built from framework contractor rates, design fees, land rights, overheads and risk elements that even experienced intermediaries say they can only partially reconstruct, and published methodology rates do not reliably match quoted figures. An intermediary managing hundreds of applications said the main difficulty is estimating costs before the quote arrives, because the point of connection is hard to predict and historic data has not been reliable.

Friction emerges when the figure meets the investment case. The connection cost is only the entry fee: running all-electric implies operating costs around 2.5 times the equivalent gas cost at current UK prices, on participant testimony. The group now compares a UK option carrying a £10 million connection charge, a five-year wait and a large operating-cost penalty against a sister site in a country with a smaller electricity-gas differential and a lower connection cost. The sector body's assessment of that comparison was direct: "You know who is going to win." Consultancy evidence describes the same pattern in live decisions: one global manufacturer prioritising a German electrification project over similar UK sites mainly because UK connection timing was uncertain, and multi-site feasibility work in which the connection can completely override everything, with the best site for electrification losing priority because its connection would cost several million more.

The customer delays. The project does not die publicly; it slips down the group's capital queue, waiting for the differential, the support offer or the connection cost to move. Five years of lead time also means the decision cannot simply be revisited later. To electrify at the next rebuild, the application would need to be made years ahead of a commitment the board has not approved, which is precisely the premature-commitment trap the evidence shows businesses avoid.

The consequence is a competitiveness question for internationally owned sites. The connection quote is one of the few components of the comparison that UK policy directly controls. Where a site proceeds with partial electrification inside existing capacity, it can also use headroom that later expansion would have needed, so production growth and decarbonisation may compete for the same connection.

**What worked:** the business obtained a real early indication of cost and timeline before formal commitment, which Case 1's (4.2.1) site never had; the trade body could aggregate and anonymise member experience, making a boardroom decision visible to the study.

**What broke down:** a headline figure without decomposition cannot be interrogated, challenged or benchmarked; there is no public, comparable dataset of actual larger I&C demand quotes across DNO regions against which anyone could test whether £10 million for 2 km is in line with comparable works; the five-year delivery indication interacts with a renewal window and an international capital comparison.

### Policy implications

1. **Mandatory itemised quote templates**, separating sole-use assets, reinforcement, contestable and non-contestable works, design and administration, with the apportionment calculation shown.
2. **Published benchmark data on actual quotes:** a regularly published, anonymised dataset of connection quotes, costs per unit of capacity and delivery timelines by region and voltage.
3. **A defined route** to have a quote's assumptions reviewed without losing queue position.
4. **Treat connection costs as industrial strategy:** International capital comparisons are decided on the combined stack of connection cost, timing and operating differential, and DESNZ should assess connection exposure explicitly in electrification support design.

#### 4.2.3 Case study 3: The infrastructure operator that cannot afford to ask for future power

##### Profile

- **Sector:** nationally significant transport and logistics infrastructure; the composite draws on a multi-site operator.
- **Connection need:** staged import-capacity growth for electrification of operations, fleet charging and customer or tenant demand.
- **What it knew:** an unusually complete picture of staged future demand across its portfolio.
- **Decision at stake:** whether the operator can commit to electrification and customer infrastructure on the timetable major users are setting.

The operator's own forecasting shows electricity demand rising materially over a long-term investment horizon. Large customer loads are a major driver, and each additional electrified activity can create a step change against existing connection capacity.

The operator can describe how its demand builds over the long term. What it cannot do is ask for all of that capacity at once. Reserving future capacity now would mean paying for headroom it will not use for years: the evidence describes capacity-based fixed charges rising with committed capacity. Holding material unused capacity can create a large recurring cost. Asking early can therefore be commercially unattractive; asking late risks the required reinforcement not being ready when demand arrives. For some future requirements the operator cannot yet specify a firm capacity figure, and the current process gives it nowhere useful to lodge that uncertainty.

The distribution network operator engaged constructively. It discussed incremental growth in stages at the focal site, with wider reinforcement planned later. To move sooner, the operator accepted a non-firm demand connection, taking capacity that can be curtailed in defined conditions.

Friction emerged at the system-operator interface and in process cost. The operator applied for the non-firm arrangement and paid a substantial deposit, then found that the system operator did not have an established policy for the non-firm demand route proposed. Separately, the operator described being charged repeatedly for technical studies and questioned why a fresh study was needed when the network had not materially changed.

The operator proceeds in phases because major customers are increasingly requiring electrified infrastructure. Delays therefore carry a commercial risk. Operationally, the focal site manages growth within limited connection headroom. The case shows a strategic infrastructure operator planning a large future demand increase through a charging and connection model that can make early capacity commitment expensive, lacks a standard product for the non-firm route it was offered, and treats a long-term investment programme as a sequence of individual applications.

**What worked:** the distribution network operator offered capacity in increments rather than all-or-nothing; a non-firm demand connection was offered and accepted, connecting load ahead of firm reinforcement; the operator's staged forecast gives planners useful information about future demand.

**What broke down:** capacity-based fixed charges can discourage early signalling of known future demand; the non-firm demand route lacked a defined system-operator policy, leaving a paid-up applicant in procedural limbo; repeated study fees were charged despite limited network change; and there was no mechanism for a multi-site operator to plan capacity across its portfolio.

### Policy implications

1. **A standard non-firm demand product**, with clear curtailment terms, review points and a route to firm status, mirroring what has existed for generation for years.
2. **Strategic demand planning for multi-site operators:** Regional Energy Strategic Plans and network operator planning should accept portfolio-level demand plans from strategic infrastructure operators as planning inputs.
3. **De-risk early demand signalling**, so that telling the network about future demand does not itself trigger prohibitive holding costs.
4. **Proportionate study fees**, justified against material network change, with prior studies reused where conditions have not moved.
5. **Connection prioritisation criteria** capable of weighing the economic role of strategic infrastructure, which first-come queue logic cannot see.

#### 4.2.4 Case study 4: The cold store that is a battery the system cannot see

##### Profile

- **Sector:** cold storage and temperature-controlled logistics; sector evidence covers around 420 cold stores using roughly 1.6 TWh of primary energy a year.
- **Connection need:** additional import capacity for electrified transport, HGV charging plus trailer refrigeration, on top of existing site refrigeration.
- **What it knew:** its load is controllable, and its control systems are built to prove it.
- **Decision at stake:** whether and where to electrify the vehicle fleet, and whether growth investment goes to this site or to one with better power access.

The need emerges from two directions at once. Refrigeration already makes the site energy-intensive, and vehicle electrification is the step change: the sector body identified

transport electrification as its biggest future challenge, because refrigerated transport adds a refrigeration power demand on top of HGV traction charging.

The customer knows something the connection process has no way to use: its load is controllable. Cold stores hold large thermal inertia. The sector body described them as a large thermal battery, able to hold temperature when demand must fall and run refrigeration harder when extra demand is useful, which is why the sector has been identified as a priority for demand-side response in both directions. Sites already sequence loads to stay within their connection: vehicles do not charge while refrigeration runs at full load, duty cycles shift overnight, and on-site solar, storage and in some cases combined heat and power fill the gaps. The site's theoretical maximum demand, every load at full draw simultaneously, is a number its control systems are specifically designed never to reach.

Yet on the sector body's account, when members approach their distribution network operator about adding load, assessment can proceed on that theoretical maximum. The controllable, pulsed character of refrigeration load, and the operational interlocks between charging and refrigeration, have no standard place in the application form or the assessment. Distribution-operator-side evidence in the study describes ramp-aware practice, so the picture is better read as inconsistency of treatment than universal failure; the point is that no defined route exists for evidencing controllability, so the outcome depends on which operator, and which engineer, a member happens to meet.

Friction follows a familiar pattern. Some members have been told local substations cannot accommodate proposed investments; one paid for an upgrade and then found a further upgrade was needed. The sector hears the same stories as everyone else and behaves accordingly: firms optimise within the connection they already have, choose new sites where power access is better, and in some cases invest in on-site gas or combined heat and power because the business case beats grid electricity, with paybacks well under ten years. The sector body was candid that direct blocked-project examples are limited today precisely because members pre-emptively avoid the connection process. Its assessment of the medium-to-long-term risk was specific: grid access could block transport decarbonisation across critical food-supply infrastructure.

The wider consequence is a double loss. The system fails to connect load that could be its friend: flexible, controllable demand at scale, often already paired with on-site generation and storage, clustered near industrial areas and ports where networks are comparatively strong. And the sector's electrification is quietly rationed by connection avoidance rather than by any explicit decision.

**What worked:** members engage directly and locally with their distribution network operators; operational load management already demonstrates in practice the controllability a flexible connection product would need; the sector body collects annual benchmarking data across its member stores, a ready-made evidence base for load profiles.

**What broke down:** assessment on theoretical maximum demand ignores demonstrable controllability, inflating the assessed requirement and the works it triggers; no standard route exists to evidence a controllable load profile in an application; repeated upgrade costs at one member site suggest weak forward-looking assessment.

### Policy implications

1. **A defined assessment route for evidenced operational load profiles**, using metered history, control-system interlocks and thermal inertia, so controllable sites are not sized and charged on a maximum they never reach.
2. **A recognised operational-evidence standard**, agreed by Ofgem and the Energy Networks Association, so treatment does not vary by operator or by individual engineer.
3. **Sector-specific flexibility design**, co-designed with sectors whose notice-period and duration needs are known and documented.
4. **Forward-looking capacity assessment** where a customer pays for an upgrade, so customers are not charged twice for consecutive increments.
5. Treat the sector's connection-avoidance behaviour as **evidence of suppressed demand** for planning purposes.

#### 4.2.5 Case study 5: The generation site that could not simply turn around

##### Profile

- **Sector:** energy and digital infrastructure development.
- **Connection need:** modifying an existing export-only connection at a renewable generation site to allow import, so an adjacent new demand development can use the established grid position.
- **What it knew:** the demand ask sat in the 5 to 10 MVA range, and the existing site already had a grid position worth reusing.
- **Decision at stake:** whether the project can be powered through the existing asset in time to hold its land position and commercial model together.

The idea is resource-efficient: an existing generation site already has a grid position, and converting or extending an export connection to allow import ought to be quicker and cheaper than building new network. The same logic appears at larger scale elsewhere in the evidence, where a data-centre case converted two substantial generation connections to demand through modification applications.

The formal process has no obvious front door for this, so the developer explored informally, through multiple grid surgeries: low-cost, roughly 45-minute conversations in which the applicant explains the project and a distribution network operator expert talks through local constraints, firmness options and capacity tipping points, including the useful news that trimming the original request could change the answer entirely. The surgeries screened out difficult options early, among them a grid supply point with no capacity in the near term unless the applicant funded a new one, and helped the developer frame better questions, in the participant's words avoiding the need to "throw stuff at the wall and see what sticks".

Information quality was personality-dependent. One distribution network operator experience was very good when a knowledgeable person was involved. In another exchange, the wrong person misinterpreted the request and warned of huge reinforcement, and was later corrected by the area planner, who said the proposal should be fine. Two answers to one question, from the same organisation.

The application proceeded, and direct dialogue between the developer's consultant and the distribution network operator's planner proved decisive. It let the developer understand what the assessment was finding before the quote arrived, and helped the project avoid a potential system-operator modification process that would have added a 90-day wait, which the participant said could have delayed the earliest offer to a point that put the project in serious jeopardy.

Friction persisted in three forms. The existing asset owner needed commercial comfort: adding import to an export agreement must not put generation revenues at risk, and no standard framework exists for that conversation. Time kills options: land was not initially secured, roughly a year passed between an early surgery and the application, and the participant's rule of thumb is that a surgery followed by six months of land work can fail because "what might have been possible nine months ago, now isn't." And the quote itself remained a black box. The participant understood the contestable and non-contestable split but experienced the non-contestable element as a monopoly, take-it-or-leave-it position, and wanted quotes to explain the decision context: which options were considered, why they were rejected, and what alternative question the applicant should ask if the offered strategy did not fit the wider project.

The wider consequence: the system's fastest and cheapest capacity, latent in existing connected assets, is accessible only to applicants with the persistence, contacts and advisory support to assemble an informal route through it. For the developer, the price was a year of elapsed time, consultant spend, and repeated exposure to jeopardy from process steps a better-defined route would have avoided or priced earlier.

**What worked:** grid surgeries, cheap, early, candid and off the record, screened options and improved the application; direct consultant-to-planner dialogue surfaced assessment findings before the quote and avoided a 90-day detour; a named, technically literate area

planner corrected a wrong early steer; the developer reused another party's expired quotes as an improvised private benchmark.

**What broke down:** no standard product or process exists for export-to-import conversion or hybrid sites, so the route ran on informality; inconsistent expertise within one distribution network operator produced contradictory constraint advice; no framework exists for the commercial triangle between asset owner, new demand party and network operator; capacity is not held or flagged during the land-assembly gap any real project needs; quotes explain the offered works and omit the alternatives considered.

### Policy implications

1. **Standardise modification and conversion applications:** a defined route, with published process steps and timescales, for export-to-import conversions and hybrid arrangements.
2. **Formalise the grid surgery** as a defined, resourced, consistently staffed distribution network operator service with published availability.
3. **Quote decision-context disclosure:** offers should state which connection strategies were considered and why the offered one was selected.
4. **A commercial template for shared assets:** standard heads of terms for adding import to an existing export connection.
5. **Short-term capacity flagging:** a time-limited, non-binding way to hold an identified option while land assembly completes.

#### 4.2.6 Case study 6: One connection, three institutions, and a date nobody owns

##### Profile

- **Sector:** large-scale commercial and industrial demand; the mechanism applies to any demand project large enough to trigger transmission assessment.
- **Connection need:** a firm, large demand connection with a bankable energisation date, connecting at distribution level.
- **Scale:** illustrative range from around 30 MW, where transmission impact assessment bites, up to a documented 120 MW case; heat-electrification schemes as small as 5 to 10 MW have triggered transmission modification processes.
- **Decision at stake:** whether the company can commit land purchase, design spend and customer contracts against a date that three institutions each partially control.

The need emerges conventionally: a large site needs power, applies to its distribution network operator and expects the operator's answer to be the answer.

The customer receives a distribution offer. The offer is real but conditional: it is issued subject to transmission impact assessment, and the assessment is only progressed after acceptance. Distribution-operator-side evidence describes the sequence in exactly those terms: the operator assesses the distribution works, sends an offer subject to transmission impact assessment, and the customer must accept, and pay, before the transmission question is examined. An intermediary quantified the exposure: obtaining a distribution quote can cost about £5,000 to £20,000, acceptance around £50,000 to £100,000, and only then does the customer wait to learn whether transmission effects will move the project. In that intermediary's experience the answer can arrive as a year of additional delay and millions of pounds of additional cost, after the customer has already spent and committed.

System-operator evidence collected for this study describes the tri-party structure from the inside. The distribution network operator retains the customer relationship but cannot confirm the transmission position alone. The system operator coordinates assessment with the transmission owner, which designs any required works. Even after a distribution offer is accepted and the assessment starts, gate decisions and transmission design can add months before the customer has a complete picture. There is no single MW threshold that determines whether every demand project requires this work; the outcome depends on the network, the relevant grid supply point and the upstream impact. In the evidence, a demand scheme of roughly 30 MW required a transmission impact assessment with an indicative minimum timescale of around eight months. Some heat-decarbonisation schemes in the 5 to 10 MW range also triggered transmission modification processes, with high fees and reinforcement-queue exposure.

Assumptions stay provisional long after money has moved. In the documented 120 MW case, the connection ran four years beyond its initial date, then took a further ten-month delay before power became firm, with non-firm status meaning defined events could switch the site off for an undetermined period. Gate criteria added interpretive uncertainty: a rule requiring a specified proportion of allocated power to be used at the allocated site was described as open to numerous interpretations, and requests for clarification as fruitless. Communication split along institutional lines. The transmission owner's communication improved markedly once customer relationship managers were appointed, while the system operator's engagement was described as webinars about gate compliance, with portal queries often left unanswered. In a parallel data-centre case, offers depended on upstream gate releases with no published dates for key steps, making scenario planning extremely difficult; connections originally due 2027 and 2028 slipped to 2033 and 2037. "The process is neither transparent nor predictable," that customer concluded.

Costs and dates move after commitment. The 120 MW customer had bought land and spent millions on design work to meet milestone obligations, design work it expects to redo nearer construction because requirements will have changed. An intermediary described multi-year slippage across schemes, and a project with a 2037 connection date where repeated requests never produced an explanation of what was driving the delay.

The customer proceeds, because sunk cost and market demand leave little alternative, but the project is now structured around institutional uncertainty. It uses phased builds, generator contingencies and renegotiated customer commitments. Some projects buy diesel or gas generation as a bridge, importing carbon and cost to work around the grid. The customer experiences one connection, while the system delivers three loosely coupled processes. When the date moves, no single institution is accountable for explaining the cause, identifying the next action and setting out any remedy.

**What worked:** the transmission owner's customer relationship managers measurably improved communication once appointed; the distribution-side quote process is comparatively regulated and predictable, with the failure concentrated after acceptance; where escalation reached the right people, engagement improved.

**What broke down:** payment and acceptance are required before the largest source of cost and date risk is assessed; no published dates for gate and assessment steps, unanswered queries, and gate rules open to multiple interpretations without an authoritative ruling; date slippage of years with no explanation, no meaningful penalty and no single responsible institution; early commitment obligations bind the customer years before power-on, while nothing symmetrical binds the delivery side.

### Policy implications

1. **Mandatory interface disclosure:** any distribution offer that depends on transmission assessment, gate decisions or upstream reinforcement should disclose those dependencies explicitly, including which body, which process and which dates are provisional.
2. **Re-sequence risk and commitment:** customers should see the transmission impact position, or a bounded assessment of it, before acceptance fees and binding milestones; where impossible, acceptance should carry defined exit or adjustment rights.
3. **A single accountable point of contact** for connections spanning distribution operator, transmission owner and system-operator processes, on the model of the transmission owner's relationship managers.
4. **Service standards with remedies at the interface,** so date changes driven by system-operator or transmission processes carry the same reporting obligations and customer remedies as distribution-side failures.
5. **Authoritative rulings on ambiguous gate criteria,** through a rapid, binding clarification route.

#### 4.2.7 Vignette: the quote nobody can benchmark

One distribution operator in the study described its connection offers as highly transparent, with individual line items for plant, equipment, traffic management, wayleaves and land

rights. It was probably right. And its own account continued: customers welcome the detail and still do not know what the items mean, because the terminology comes from contractor frameworks, and wording changes are messy.

Itemisation, it turns out, is not the same thing as challengeability. A connections specialist managing hundreds of projects told the study that published charging-methodology rates do not reliably match the rates in actual quotes, that base prices form in ways that are not a clear process, and that on large jobs a £2 million quote “could just as likely be £4 million when you finish.” A high-volume applicant said some offers arrive with no itemised breakdown at all, costs lumped together against a written description they cannot be matched to, and that the reinforcement apportionment calculation, the one number that would let a customer test their share, has disappeared from even the better offer templates. Meanwhile no distribution network operator publishes a comparable GB-wide set of project-level cost outturns for larger I&C demand connections; annual reporting gives average time-to-connect by broad segment, which one operator conceded is relatively vague.

So even a diligent customer with a fully itemised quote has nothing to compare it against: no dataset of actual quotes for similar works, no regional cost-per-MVA benchmarks, no published queue or timeline distributions. The evidence shows what customers do instead. An experienced developer reviewed another party's old and expired quotes as improvised data points, and intermediaries test contestable elements by tendering them, which works only for the contestable share.

The policy point is short. Transparency that stops at the quote document is decorative. A quote becomes challengeable when the customer can put it next to what other customers actually paid, and that requires published, anonymised benchmark data on real quotes, costs and timelines, which no institution currently provides.

#### **4.2.8 Vignette: the formal application that never happened**

An industrial site in Scotland was electrifying its process heat and running at the limit of its existing connection. It briefly explored increasing its import capacity. Then it dropped the idea. There is no record of that decision in any queue statistic, because there was nothing to record: no application was made and no quote was issued.

Participants described this pattern across dispersed industrial sites. Sites hold informal conversations with their network operator, receive an indication that delivery could be years away, and sometimes never enter the formal process. Conversations can stop once the timeline becomes apparent. The mechanism is specific: industrial decarbonisation investment rides on machinery end-of-life windows, and where the connection indication is eight years and the kit expires in two, the business may have to reinvest in gas and miss the electrification window for an asset generation. There is no formal process for recording a project deterred before applying, so nothing is counted.

The result is a measurement trap. Connections reform is scored on queue length, quote turnaround and acceptance rates, indicators that improve when discouraged projects stay away. A system that quietly deters demand can look like a system that is working. Reform needs its own denominator: deterred and paused projects should be counted, through periodic sector surveys, enquiry-stage data and a non-committal demand register, and treated as a headline performance measure alongside queue statistics.

#### **4.2.9 Vignette: the good DNO conversation**

A developer trying to power a novel project did not start with an application form. It started with a grid surgery: a 45-minute conversation, at low or no cost, in which the applicant explained the project and a distribution network operator expert talked through local constraints, firmness options and tipping points. Nobody was formally on the hook, and that was the point.

The conversations kept paying. Surgeries screened out a grid supply point with no capacity available before any money was spent on it. Later, direct dialogue between the developer's consultant and the distribution operator's planner surfaced what the assessment was finding before the quote arrived, and helped the project sidestep a modification process that would have added a 90-day wait at a moment that could have put the scheme in serious jeopardy. When a less experienced contact misread the request and warned of huge reinforcement, the area planner corrected it: the proposal was fine.

The distribution-operator side of the study shows the commercial logic of such conversations: queue hygiene. One operator described connection surgeries, budget routes and application charges together lifting offer acceptance rates from around 10 to 15% to over 40%, because early honest conversations filter out applications that were never going to proceed and improve the ones that do. An intermediary's description of good practice was almost mundane: a named contact who picks up the phone, calls back, follows up when the quote lands and convenes the right people when something goes wrong.

Good service here changed which options were pursued and when land was committed, and it decided whether the project survived. The policy question is why access to it should depend on knowing whom to ask.

## **5 What the cases reveal**

The six cases and three vignettes (4.2) describe different sectors, scales and entry points, and the same system. This section draws out the recurring sources of cost uncertainty that run across them, and what each means for where reform should concentrate. Seven recur, and they compound: a business facing two or three of them at once experiences a single problem, a connection it cannot price.

## **5.1 Unknown total cost**

The most basic uncertainty is the first one the cases show: businesses cannot find out what they are likely to pay until they are already committed. The manufacturer in Case 1 (4.2.1) could not obtain an indicative range without entering a process it was not ready for. The infrastructure operator in Case 3 (4.2.3) paid a substantial deposit into a process for which the system operator lacked an established policy. The developer in Case 5 (4.2.5) improvised a benchmark from another party's expired quotes.

The gap is specific. Published charging methodologies explain the formal rules, and capacity maps and open-data tools have improved. What none of them provides is the investment answer a customer needs at the start: what am I likely to pay, why, and how uncertain is that figure? Between the methodology and the quote sits a translation that customers, and by their own account some distribution network operator staff, cannot perform. The gap is partly presentational and partly structural: the minimum-cost design required at quote stage is not always the most deliverable solution, and design assumptions can move when work reaches the delivery team. Because no institution publishes actual quote outturns, a customer holding a figure for two kilometres of network has no way to judge whether it is reasonable, cautious or wrong.

The system change this points to is early, decision-grade cost indication: indicative ranges with stated assumptions and confidence levels at enquiry stage, and a published, anonymised benchmark dataset of real quotes, costs per unit of capacity and timelines. Section 6 develops what distribution network operators can realistically provide early without giving false certainty.

## **5.2 Reinforcement and asset allocation**

Where a figure does exist, the next uncertainty is what it is made of. Customers in the evidence could rarely establish how much of a quote was sole-use assets, how much was reinforcement, what triggered the reinforcement element, or how their share was apportioned. One high-volume applicant reported that the apportionment calculation has disappeared from even the better offer templates. The developer in Case 5 (4.2.5) could see the contestable and non-contestable split but experienced the non-contestable element as a take-it-or-leave-it monopoly position.

The Access SCR was meant to settle much of this for demand customers by moving most reinforcement to shallow charging, and it has reduced upfront exposure. What it has not done, on this evidence, is make quotes legible. Participants still could not reconcile published rates with quoted figures and still could not see the rationale for the minimum scheme, the assumptions underneath it, or what would change the number. The detail that exists is itemisation; what customers need is the reasoning. A quote that lists equipment without showing the apportionment mathematics or the options considered cannot be interrogated, and a customer who cannot interrogate a quote cannot challenge one.

The direction of change is disclosure of reasoning, and it costs little: show the apportionment calculation, state the assumptions, log them when they move, and explain why the offered scheme was chosen over the alternatives.

### **5.3 Transmission-linked uncertainty**

The sharpest cost and date risk in the evidence sits at the seam between institutions. Case 6 (4.2.6) shows the sequence: accept and pay, then learn whether transmission effects will move the project. Fee exposure at acceptance can run to tens of thousands before an assessment that may add a year and millions. A 30 MW scheme faces a fixed minimum assessment period of around eight months; smaller heat-decarbonisation schemes can now trigger transmission modification processes with a high fee and the risk of a reinforcement queue. Connection dates slipped by several years across the schemes intermediaries described; examples included a connection moving from 2027 to 2033 and another moving from 2028 to 2037, without explanation.

The tri-party structure compounds the difficulty. As system-operator participants confirmed, a distribution offer alone does not give the customer a complete picture: the distribution network operator holds the customer relationship and delivers distribution works, but the system operator coordinates transmission assessment and the transmission owner designs transmission-level works, each on its own timeline. The result is a customer who experiences one process and the system delivers three loosely coupled ones. Service levels apply at each institutional boundary, but transmission reinforcement is outside those standards, and the combined impact is felt by the customer without any single institution owning it.

The regulator's caution belongs alongside this. In its assessment, interface friction accounts for months rather than the full multi-year slippage, much of which reflects genuine constraint and delivery limits. The distinction matters less to the customer than it might. What the customer cannot obtain is an account of cause: which body, which process, which dependency moved the date. Accountability follows the institutional split, and the customer's exposure is left without an owner.

The change the cases point to is sequencing and ownership: transmission dependencies disclosed before acceptance, bounded assessments before binding fees where possible, one accountable contact spanning the institutions, and remedies that do not stop at the distribution operator's organisational boundary.

### **5.4 First mover exposure and the queue**

Queue reform was live throughout the fieldwork, and every participant supported tighter queue discipline. The regulator described it as a central precondition for demand connection predictability. The evidence also shows what queue reform does not solve. Readiness tests front-load cost before the system delivers any certainty, and viable projects can fail them on technicalities. Strategic prioritisation criteria are not public or contestable, and participants questioned who decides what counts: in one consultant's words, "How do we develop the UK economy without prioritising 40 years' worth of data centres before we

can do anything else?" Risk shifts onto smaller, slower applicants without freeing capacity for them. Queue reform redistributes places in the queue; the underlying scarcity remains.

Two specific gaps stand out. Non-firm demand has no equivalent of the established non-firm generation route: the infrastructure operator in Case 3 (4.2.3) hit exactly this wall, paying a deposit into a process without an established policy. The acceleration and priority routes intended for strategic projects are also not landing consistently. Multiple participants across the study independently reported that at least one relevant scheme lacks clear rules, published criteria or any demonstrated effect; one trade body reported that no member had been through it, and that one distribution network operator it approached did not know the scheme existed.

The deliverable ask here is narrow and concrete: a standard, reusable non-firm demand product across the distribution and system-operator interface, and priority routes with published criteria and demonstrable effect.

## **5.5 Ongoing network charges**

Upfront connection costs and ongoing network charges are different things, and the report keeps them separate, but Case 3 (4.2.3) shows why they belong in the same conversation about early confidence. Band-based capacity charges rising steeply over the planning horizon turn early capacity commitment into a recurring liability. The customer that most wants to signal future demand is the customer the charging structure most penalises for doing so. Where charging design makes prudent forward requests irrational, demand visibility suffers with it, and the network plans against a future its own price signals have suppressed.

## **5.6 Administrative and opportunity costs**

Delay is a cost even when no invoice arrives. The cases record staff time, consultant spend, repeated study fees for unchanged networks, design work done to meet milestones and expected to be redone, land held at risk through the assembly gap, and board confidence eroding with each moved date. The 120 MW customer in Case 6 (4.2.6) spent millions on design it expects to repeat. The developer in Case 5 (4.2.5) lost a year assembling informally what a defined process would have provided.

This is where the study's most consistent message, that timescales worry participants more than cost, resolves into the cost story. Time converts to cost inside the business long before it appears in any connection charge, and timeline uncertainty destroys the value of cost information: a price that cannot be trusted to hold across the delivery period gives a board nothing it can approve. For industrial sites the conversion is terminal, because connection timelines compete with fixed renewal windows. An offer that arrives after the window closes has no value, and the site may have to reinvest in gas for an asset generation.

## **5.7 Entering the process too early**

The final uncertainty is the trap the system sets at its entrance. Useful cost information sits inside the formal process; businesses cannot responsibly enter the formal process until their project is mature; projects cannot mature without cost information. Case 1 (4.2.1) shows the result: exploration stops at informal signals, and the project pauses without ever formally existing. Case 2 (4.2.2) shows the same trap from the other side: five years of lead time means the application must precede the board approval it is supposed to inform.

The consequence is suppressed demand for connections that no dataset records. Trade bodies described members deterred by informal timeline indications, while a government participant observed that industry is not applying at anything near the scale net zero requires. No process counts projects that stop before application. This creates a perverse measurement effect: queue and turnaround indicators can improve when potential applicants stay away. The evidence does not indicate deliberate deterrence by network operators. It shows that current metrics omit the demand lost before the measured process begins.

What would change this is a legitimate early route: non-committal demand signalling into planning, decision-grade pre-application information out of it. Section 6 sets out what that exchange should contain.

## **5.8 What this adds up to**

Connection cost has become a board-level competitiveness signal. The clearest comparison in the evidence put a UK connection for one energy-intensive site at around £10 million, with a five-year wait and an operating-cost disadvantage, against overseas options with lower connection costs and more favourable electricity-gas economics. Separate consultancy evidence described one global manufacturer prioritising a German electrification project over similar UK sites mainly because UK connection timing was uncertain. The binding variable is rarely the absolute cost alone. It is cost uncertainty, multiplied by timeline uncertainty, landing on top of an electricity-gas price differential that already strains the case for electrification. Connections reform cannot fix the differential, and this report does not ask it to. What connections reform can fix is the uncertainty: the quote that cannot be interrogated, and the date that nobody owns. It can also give a demand signal somewhere to go.

The cases also show that good practice already exists inside the current framework. Grid surgeries screened options and saved projects. Phased offers and non-firm arrangements connected load early. Named contacts and relationship managers transformed communication where they existed. None of this required new legislation; all of it depended on which organisation, and sometimes which individual, the customer happened to reach. The reform task, developed in the next two sections, is to turn that good practice from luck into entitlement, and to give businesses what the current system cannot: cost confidence early enough to matter, and attribution clear enough to challenge.

Uncertain industrial demand also needs a way to be seen by planners before any application form is filled in.

## **6 Where the system needs to intervene earlier**

The cases point to the same place. The decisions that determine whether a site electrifies are taken, or quietly dropped, before any formal application exists. The manufacturer in Case 1 (4.2.1) paused its project at the informal enquiry stage. The Scottish site in the accompanying vignette abandoned an import increase without generating a single record. The developer in Case 5 (4.2.5) spent a year assembling informally what a defined process would have provided in weeks. By the time a customer enters the formal process, the money, the staff time and often the decision itself have already been committed. This section sets out what an earlier intervention should look like: what customers can reasonably bring to the network operator, what the network operator can reasonably provide in return, and how to fund and staff that exchange without pretending to a certainty that does not exist at the early stage.

### **6.1 The early-stage support that already works**

The evidence contains working examples of good early-stage practice, and they share a character: cheap, early, candid and non-binding.

The clearest is the grid surgery. For the developer in Case 5 (4.2.5), a series of roughly 45-minute conversations, at low or no cost, screened out a grid supply point with no available capacity before any money was spent on it, and identified the capacity tipping point at which a smaller request would change the answer entirely. The eventual application asked better questions because of them. Regular informal liaison meetings served the manufacturer in Case 1 (4.2.1) similarly, surfacing potential capacity availability early. A high-level enquiry route exists and costs little.

The distribution-operator side of the evidence explains why this is worth an operator's resource. One operator described connection surgeries, budget quote routes and application charges together lifting offer acceptance rates from around 10 to 15% to over 40%. Early honest conversations filter out applications that were never going to proceed and improve the ones that do. Early-stage support is queue hygiene as much as customer service: better feasibility information reduces the use of formal applications as feasibility probes, which operators themselves identify as a source of queue noise and stranded capacity reservations.

Good early practice is already known; access to it is what remains unreliable. The value of a surgery depended, in the Case 5 (4.2.5) evidence, on the right expert being present; the wrong contact produced a warning of huge reinforcement that the area planner later corrected. The manufacturer in Case 1 (4.2.1) received informal multi-year timeline indications with no options and no explanation attached, and treated them, reasonably, as a refusal. The same early conversation can save a project or end one, depending on who is

in the room. Turning good practice from luck into entitlement means defining and resourcing the service, then measuring whether customers can actually get it.

## 6.2 What customers can reasonably bring

An early conversation only works if the customer brings enough information to make it useful. The evidence is specific about what a minimum viable set looks like, and about its floor. A business at the pre-application stage should be able to describe:

- **a rough electrification pathway:** what process or load is being electrified, and in what stages
- **the site location,** or the locations across a portfolio
- **an approximate capacity requirement in MW,** as a range rather than a point
- **desired timing,** including any fixed asset-renewal window
- **current energy use,** with gas consumption as the fallback where a site cannot yet calculate an electrical requirement
- **peak demand assumptions,** including any controllability or load management the site can evidence
- **an honest statement of project maturity and uncertainty**

None of this requires design work or fees. A government participant described the floor directly: where a site cannot calculate its electrification need, converting gas consumption into an electrical equivalent and sending that through is better than nothing. The point of the minimum set is to let the network operator's planners do something useful with it, and to make the exchange low-burden enough that the businesses most likely to be deterred, the first-time decarbonisation customers described by operators as needing translation and options work, can actually take part. Trade bodies have a role here that Section 7 returns to: helping members assemble a plan of this kind is well within their competence and reach.

## 6.3 What customers cannot reasonably know

The other half of the exchange follows from what sits inside the network operator's models and nowhere else. A customer cannot know the available headroom at their point of connection, whether their request lands on the cheap or expensive side of a voltage or reinforcement threshold, what the likely point of connection is, or whether upstream transmission effects will bite. These are the decisive inputs to cost, and the cases show that even the most sophisticated actors cannot extract them early. The intermediary in Case 2 (4.2.2) managing hundreds of applications said the central difficulty is estimating costs before the quote arrives, because the point of connection is hard to predict and historic data has been unreliable.

This asymmetry is the reason early cost indication has to come from the network operator. No amount of customer preparation, consultant spend or published methodology reading

can substitute for a view inside the network model. A system that withholds that view until formal application is asking businesses to make investment decisions blind, and Section 5 records the responses: businesses may reinvest in gas, reprioritise investment elsewhere, or stay away from the process altogether.

#### 6.4 What DNOs can provide without false certainty

The objection to early cost indication is that early figures will be wrong. The evidence supports the concern but not the conclusion. Customers already distrust early indications, which is precisely why they submit formal applications as feasibility probes. The remedy is early information built to be trusted for what it is: a range with its reasoning shown, revisable on stated grounds, rather than a point estimate that pretends the assessment has been done.

At enquiry stage, on the evidence of what good practice already achieves, a distribution network operator should be able to provide:

- **indicative connection options**, of the kind a government participant sketched as option one, two and three with approximate costs
- **a rough cost range for each**, with the assumptions stated
- **the known constraints that shape the answer**, including any dependence on transmission processes
- **what would change the number**: the thresholds, triggers and request sizes that move the cost materially
- what **further information** from the customer would narrow the range
- **a confidence level**, so the customer knows how much weight the figure can bear

The last three items matter as much as the range itself. A figure that arrives with its sensitivity and its confidence attached can inform a board paper honestly. A bare figure cannot, and a bare figure later corrected is worse than no figure, because the correction lands after commitment. The test for any early-stage product is whether a customer can take it into a site-selection or investment decision knowing what it does and does not promise. That test came from a distribution network operator participant, and it is the right one.

Honesty about uncertainty also protects the operator. An indicative range with stated assumptions is not a quote. It reserves no capacity and invites no reliance beyond its terms. The current alternative, silence until formal application, does not avoid misleading customers. It leaves the field to the sector rumour mill, which the Case 1 (4.2.1) evidence shows circulating horror stories in place of data.

#### 6.5 The resource question

Early-stage support is not free, and the evidence is candid about the burden. A high-touch service could require distribution network operators to maintain substantial ongoing teams

and to carry much of the information-gathering effort. One operator drew the boundary plainly: the operator cannot act as the customer's electrical consultant.

Both points are fair, and neither is an argument for the status quo. The boundary implies a shared model rather than a smaller one. Operators provide what only they can: indicative options, constraint information, threshold effects, confidence levels. Advisers and installers help customers define behind-the-meter requirements. Trade bodies help members assemble the minimum viable plan and aggregate demand evidence. Each party carries the part of the burden it is best placed to carry, and the operator's share, while real, is bounded.

The funding route runs through the price control. ED3 will set what distribution operators are resourced and incentivised to do for the rest of the decade. At present the measured dimensions of connections service are speed and satisfaction; early cost confidence has no metric, so no operator is rewarded for providing it or penalised for withholding it. If pre-application support of the kind described here is to be an entitlement, ED3 has to fund it and measure it. The acceptance-rate evidence suggests the net cost is lower than it appears, because effective early support displaces the cost of processing speculative applications that better information would have prevented.

There is also a distributional reason to fund it. The customers who most need early translation, the dispersed industrial sites without specialist energy resource, are the least equipped to demand it and the most likely to be deterred by its absence. They are also, on the government evidence in this study, the sites industrial electrification policy most needs to reach. A pre-application service designed around the expert customer serves the customers who least need it.

## **6.6 From early conversations to visible demand**

One gap remains even if every distribution network operator offered excellent early support. A site that explores informally and pauses, like the manufacturer in Case 1 (4.2.1), still leaves no trace. Its demand remains invisible to network planners, to Regional Energy Strategic Plans, and to the national picture of industrial electrification need. Early support helps individual customers; it does not, by itself, let the system see the demand that is not yet ready to apply.

That requires a route for uncertain demand to be lodged somewhere useful, without fees, capacity reservation or queue obligations: the minimum viable information described above, offered as a planning signal rather than an application. The exchange should run both ways, with the site receiving indicative constraint information in return. Section 7 sets out that recommendation in full, as a firm ask of NESO, alongside the changes each other actor owes the early stage of the process.

## 7 Policy mapping and recommendations

The recommendations in this section are built from the cases. The mapping table below states what the evidence shows industrial and commercial businesses need, and where each need could be met in work already in train. The order of the columns is deliberate: the need comes first and the policy vehicle follows, rather than starting from existing policy boundaries and asking what fits inside them. Actor-specific recommendations follow for DESNZ, Ofgem, NESO, the distribution network operators, and industry and trade bodies. Each one traces back to a case or to a synthesis theme in Section 5.

|   | What businesses need                                                                                                                                                        | Where this could be addressed                                                                                                                        |
|---|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1 | Earlier indicative cost visibility, as a range with stated assumptions and a confidence level, before any formal commitment (Cases 1, 2, 5)                                 | DNO pre-application services and optioneering; ED3 Larger Connections Incentive and Connections Strategy requirements; end-to-end connections review |
| 2 | Clearer allocation of reinforcement and shared-asset costs, with the apportionment calculation visible and sole-use treatment explained (Cases 2, 5; benchmarking vignette) | Ofgem charging work; minimum offer-content standards; ED3                                                                                            |
| 3 | Clarity on transmission-related pass-through costs and dependencies, disclosed before acceptance (Case 6)                                                                   | Ofgem and the DNO, TO and NESO interface; transmission impact assessment sequencing; end-to-end connections review                                   |
| 4 | A mechanism for non-committal demand signalling with no fees, capacity reservation or queue obligations (Cases 1, 3; deterred-application vignette)                         | NESO demand register; outputs to Regional Energy Strategic Plans; DNO investment planning through ED3                                                |
| 5 | A standard non-firm and flexible demand route, with assessment recognising evidenced controllability (Cases 3, 4)                                                           | NESO policy for non-firm demand; Ofgem charging and access work; DNO connection product design                                                       |
| 6 | Better support for industrial sites without specialist energy resource (Case 1; Section 6)                                                                                  | DNO pre-application engagement; DESNZ support design; trade bodies and member networks                                                               |
| 7 | Recognition that timelines create internal business costs, with disclosure and remedies where dates move after acceptance (Cases 2, 6)                                      | End-to-end connections review requirements on dates, cross-institution reporting and customer remedies; ED3 delivery standards                       |
| 8 | Separate reporting of industrial electrification and data-centre demand where policy purposes                                                                               | DESNZ analysis and support design; NESO queue and system planning; Regional Energy Strategic Plans                                                   |

|    | What businesses need                                                                                                                                                                            | Where this could be addressed                                                               |
|----|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------|
|    | differ, with shared planning for overlapping network needs (Section 3; Case 6 context)                                                                                                          |                                                                                             |
| 9  | Published benchmark data on actual connection quotes, costs and timelines (Case 2; benchmarking vignette)                                                                                       | Ofgem reporting requirements; ENA and DNO data publication; trade body evidence sharing     |
| 10 | Practical routes that reduce dependence on the incumbent delivery model, including greater self-build, standard flexible demand products and defined hybrid or conversion routes (Cases 3 to 5) | Ofgem Demand Connections Reform, Connect pillar; DNO product design; NESO and DNO interface |

Two points sit underneath the table. Most of these needs concern information design and process sequencing, so existing regulatory mechanisms can deliver them without new public spending. Targeted support for upfront connection costs is the main funding exception and is addressed to DESNZ below. The needs also interact. Early indicative costing works best when a demand register surfaces the sites that need it. The register only fills if businesses trust what comes back, and remedies for slipped dates depend on offers that disclosed their dependencies in the first place. These policy streams are run separately. The evidence says they have to be coordinated, because a reform in one stream can be undone by a gap in another.

The cost treatment in this section is deliberately qualitative. The figures in the case sections are participant-reported and are presented there with their caveats attached. The evidence base does not support quantified cost ranges by archetype, and none are offered.

## 7.1 For DESNZ

**Include upfront connection costs in targeted industrial electrification support.** The competitiveness evidence is direct. In Case 2 (4.2.2), a group-level capital allocation considered a UK connection cost of around £10 million, a five-year wait and an operating-cost differential against lower-cost alternatives overseas. The connection quote is one of the few components of that comparison UK policy directly controls. Current support is weighted towards ongoing charges; one participant noted that network-charge compensation can cut fixed charges substantially while leaving the upfront connection cost untouched. Where a formal offer is unavailable, support design should accept a documented indicative DNO range and reconcile against the later formal offer. (Cases 1 (4.2.1) and 2 (4.2.2); Section 5, unknown total cost and what this adds up to.)

**Align industrial electricity-cost support with electrification.** The final BICS design does not apply an individual-business electricity-intensity test; eligibility is assessed at sector

level, with exemptions pro-rated at site level according to the share of electricity used for eligible manufacturing. DESNZ should work with DBT to ensure that electrification projects can understand, before investment, how new electrical load will be treated under BICS and the separate British Industry Supercharger rules. Where future electricity use affects site-level support calculations, guidance should allow forward-looking engineering evidence. (Case 1 4.2.1.)

**Commission measurement of deterred demand, jointly with Ofgem.** Projects abandoned before formal application appear in no queue statistic, and government participants in this study were clear that industry is not applying at anything near the scale net zero requires. Periodic sector surveys, enquiry-stage data collection and register data should be used to count deterred and paused projects, and the result treated as a headline connections performance measure alongside queue statistics. A system that quietly deters demand can otherwise look like a system that is working. (Case 1 (4.2.1); deterred-application vignette above; Section 5.7, entering the process too early.)

**Recognise asset-renewal windows in electrification support design.** Industrial electrification decisions ride on machinery end-of-life windows. A connection offer that arrives after the window closes has no value at any price, and the site may have to reinvest in gas for an asset generation. Support schemes and any connections prioritisation criteria should treat a documented renewal window as material. (Cases 1 (4.2.1) and 2 (4.2.2) above.)

**Separate industrial electrification and data-centre demand where the policy purpose requires it.** Government should report them separately when assessing industrial decarbonisation, support eligibility and the source of queue pressure. Network planning should also recognise the overlap. Both can involve large step-change loads in the same regions, and both may benefit from earlier cost information, staged connections, flexible products or self-build routes. This approach avoids using data-centre evidence as a proxy for industrial need while retaining evidence that is relevant to shared network problems. (Section 3; Section 5, first mover exposure and the queue.)

## 7.2 For Ofgem

The recommendations below map directly onto two live Ofgem workstreams. Quote quality, data visibility, connection dates and cross-institution accountability sit within the End-to-End Connections Review. Practical delivery routes, including self-build, flexible demand and hybrid arrangements, sit within the Connect pillar of Demand Connections Reform. ED3 provides the funding and incentive framework needed to make these requirements routine.

**Make quote transparency an enforceable minimum standard under the End-to-End Connections Review.** Offers should use a standard template that separates sole-use assets, reinforcement, contestable work, non-contestable work, design and administration. The offer should show the reinforcement apportionment calculation, state the assumptions

underneath the minimum scheme and explain which connection strategies were considered. High-volume applicants report that the apportionment calculation has disappeared from some of the better templates. The evidence shows that voluntary practice has not produced consistency, while itemisation without reasoning cannot be challenged. (Cases 2 (4.2.2) and 5 (4.2.5); benchmarking vignette; Section 5.2, reinforcement and asset allocation.)

**Require published benchmark data on actual quotes through the End-to-End Connections Review's data-visibility work.** No institution currently publishes project-level quote or cost-outturn data, so a customer holding a figure for two kilometres of network has no way to judge it against comparable works. A regularly published, anonymised dataset should cover connection quotes, component costs, cost per unit of capacity and delivery timelines by region and voltage. Customers would gain a benchmark, while Ofgem would gain an oversight tool. Distribution network operators would also have evidence with which to answer perceptions of arbitrary pricing. (Case 2 (4.2.2); benchmarking vignette (4.2.7).)

**Use ED3's Larger Connections Incentive and Connections Strategy requirements to strengthen pre-application support for major demand.** Ofgem's May 2026 methodology decision did not introduce a separate strategic-demand incentive at this stage, so the practical route is through DNO business plans and the larger-connections framework. The service should provide an indicative cost range with stated assumptions, known constraints and a confidence level. Performance reporting should cover enquiry-stage demand as well as formal applications, so an apparent improvement cannot be produced by potential applicants stopping before the measured process. One operator reported that early support increased offer acceptance from around 10 to 15% to over 40%. (Section 6; Cases 1 (4.2.1) and 5 (4.2.5).)

**Clarify allocation rules that customers cannot currently test.** Sole-user treatment of substations and similar assets can be hard to understand for large industrial connections. The demand high-cost threshold is set per kVA, so projects can face different reinforcement exposure depending on capacity and the cost of the work triggered. First mover exposure also remains where one project funds assets that later users share. In each area customers need enough information to understand how the rule has been applied to their project. The same facts should produce the same charge across operators. (Section 5, reinforcement and asset allocation, first mover exposure; Case 2 (4.2.2).)

**Examine whether charging arrangements support industrial electrification.** Two charging effects in the cases work against stated policy aims. Band-based capacity charges price early capacity commitment as a recurring liability, so the customer that most wants to signal known future demand is the customer most penalised for doing so. And assessment on theoretical maximum demand, where applied to evidenced controllable loads, inflates the assessed requirement and the works it triggers. Ofgem's charging work should test

both against the electrification objective. (Cases 3 (4.2.3) and 4 (4.2.4); Section 5.5, ongoing network charges.)

Use the Connect pillar of Demand Connections Reform to widen practical delivery routes. Ofgem should test greater self-build and high-voltage asset ownership for capable demand customers, with clear operational and safety requirements. It should also require standard flexible, non-firm and ramped-demand products, alongside defined routes for co-location, export-to-import conversion and hybrid assets. These options should reduce dependence on a single minimum-scheme offer without weakening network security. (Cases 3 (4.2.3) to 5 (4.2.5).)

**Use the End-to-End Connections Review to set cross-institution service standards and remedies.** Any date change caused by transmission assessment, a gate decision or transmission-owner delivery should identify the responsible process, the reason for the change and the next decision date. One accountable contact should give the customer that explanation. Reporting obligations and any remedy should follow the effect on the customer instead of stopping at the distribution operator's boundary. (Case 6 (4.2.6); Section 5 (5.3), transmission-linked uncertainty.)

### 7.3 For NESO

**Stand up the in-development demand register, and make it work for uncertain industrial demand.** This report treats the register as a firm ask, because it is the mechanism on which several other reforms depend: deterred demand cannot be measured, Regional Energy Strategic Plans cannot plan, and early distribution network operator support cannot reach the right sites while uncertain demand remains invisible. The design conditions are specific and come from the evidence. The register must accept ranges and rough, non-binding estimates rather than application-grade data, and it must be commercially safe, with confidentiality and explicit non-commitment.

It also has to return something useful to every site that registers, such as indicative constraint information or a planning signal, because a register that only collects will stay empty. NESO should coordinate contact between registered sites and distribution network operators so that businesses are not left chasing each operator individually. The resulting demand picture should feed into Regional Energy Strategic Plans and DNO investment planning through ED3.

The register is a planning tool, not a substitute for formal applications. System-operator evidence confirms that formal applications remain the strongest signal of committed demand, and the register is not designed to change that. Its purpose is narrower: to make uncertain, uncommitted demand visible to planners earlier, so that network investment decisions are shaped by a fuller picture of what is likely to arrive. A site using the register to signal rough intent is not making an application; it is giving the planning system something to work with. (Cases 1 (4.2.1) and 3 (4.2.3); Section 5.7, entering the process too early; Section 6.)

**Publish a standard non-firm demand policy.** Non-firm generation arrangements have existed for years; a strategic infrastructure operator in this study paid a substantial deposit into a non-firm demand application and found there was no established policy for it. A standard product, with clear curtailment terms, review points and a defined route to firm status, should exist across the distribution and system-operator interface. (Case 3 (4.2.3); Section 5.4, first mover exposure and the queue.)

**Publish dates and criteria for gate and assessment steps, with a rapid clarification route.** Customers described gate criteria open to numerous interpretations, clarification requests left unanswered and key steps with no published dates, making scenario planning close to impossible. Ambiguous criteria need an authoritative, binding ruling route; process steps need published timescales. (Case 6 (4.2.6).)

**Support a single accountable contact for connections that span institutions.** Where a connection crosses distribution operator, transmission owner and system-operator processes, the customer experiences one connection while the system delivers three loosely coupled processes. The transmission owner's customer relationship managers measurably improved communication once appointed. That model should extend across the interface, so one named contact is accountable for explaining the cause when a date moves and setting out the next action. (Case 6 (4.2.6).)

## 7.4 For DNOs

**Make the grid surgery a defined, resourced, consistently staffed service.** Early non-binding technical conversations demonstrably changed outcomes in the evidence, screening out dead options before money was spent and improving applications. Their value currently depends on the right expert being present. Publish availability, staff them with local network expertise, and treat them as part of the connections service rather than a favour. (Case 5 (4.2.5); good-conversation vignette (4.2.9); Section 6.)

**Provide indicative cost ranges at enquiry stage, with assumptions and confidence levels stated.** Section 6 sets out the exchange: minimum viable information from the customer; indicative options, ranges, known constraints, threshold effects and confidence levels in return. The purpose is decision-grade honesty, a reliable range rather than a false point estimate. (Cases 1 (4.2.1), 2 (4.2.2) and 5 (4.2.5); Section 6.)

**Show the reasoning in every offer.** Disclose the apportionment calculation, the assumptions under the minimum scheme, what would change the number, and the options considered. This costs little and converts itemisation into challengeability. (Cases 2 (4.2.2) and 5 (4.2.5); benchmarking vignette (4.2.7).)

**Define standard routes for modification and conversion cases.** Export-to-import conversion and hybrid arrangements currently run on informality, persistence and contacts, even though latent capacity in existing connected assets is some of the fastest and cheapest capacity the system has. A defined route with published steps and timescales, a commercial template for adding import to an existing export connection, and a time-limited way to flag

an identified option while land assembly completes would move this from workaround to product. (Case 5 (4.2.5).)

**Charge study fees proportionately and assess capacity forward.** Repeated fees for technical studies on a materially unchanged network, and consecutive upgrade charges where a forward-looking assessment would have caught the second increment, both appear in the evidence and both corrode trust disproportionately to the sums involved. Reuse recent studies where conditions have not moved; assess foreseeable growth when a customer pays for an upgrade. (Cases 3 (4.2.3) and 4 (4.2.4).)

**Create an assessment route for evidenced controllable load.** Where a customer can evidence controllability through metered history, control-system interlocks and operational practice, assessment should be able to use that evidence rather than a theoretical maximum the site is engineered never to reach. Consistency matters as much as the route itself: treatment should not depend on which engineer a customer happens to meet, which points to a recognised operational-evidence standard agreed with Ofgem and the Energy Networks Association. (Case 4 (4.2.4).)

**Treat portfolios and clusters as planning signals.** A multi-site operator's forecast of staged demand growth is exactly the strategic information a planning system should want, and the current process treats it as a sequence of unrelated applications. Portfolio-level demand plans from strategic infrastructure operators should be accepted as planning inputs, into operator plans and through to Regional Energy Strategic Plans. (Case 3 (4.2.3); multi-site evidence in Section 5.)

## 7.5 For industry and trade bodies

**Help members build minimum viable electrification plans.** The floor is deliberately low: rough pathway, locations, approximate MW as a range, desired timing, current energy use with gas-consumption equivalence as the fallback, and an honest uncertainty statement. This is the customer's side of the early exchange in Section 6 and the entry ticket to the register, and it is well within trade body competence to support. (Case 1 (4.2.1); Section 6.)

**Build anonymised benchmarking from member evidence.** Redacted quote letters, component costs and timeline histories, shared through trade bodies, would give members a benchmark that does not currently exist for larger I&C demand connections across DNO regions, and would strengthen the case for the published dataset recommended to Ofgem. Sector bodies that already run annual benchmarking, as the cold-chain evidence shows, have the machinery to do this. (Case 4 (4.2.4); benchmarking vignette (4.2.7).)

**Keep connection costs distinct from the wider electricity price argument.** The cases show the two stacking in investment decisions, and the report presents them as one compounding story, but the policy owners differ. Conflating them lets each owner point at the other. Trade bodies are well placed to keep the distinction sharp in evidence they submit. (Case 2 (4.2.2); Section 5.8, what this adds up to.)

**Aggregate sector demand into Regional Energy Strategic Plans and regional planning.**

Individual members cannot resource sustained engagement with regional planning processes. Trade bodies can carry sector-level demand evidence into planning at a level individual sites cannot, and the register gives that evidence somewhere to land. (Cases 1 (4.2.1) and 4 (4.2.4); Section 6.)

## 8 Conclusion

This report set out to name what industrial and commercial businesses are afraid of when they approach the electricity network, and the cases have named it. The fears are specific: a total cost that cannot be estimated before committing, allocations that cannot be seen or challenged, costs and delays that arrive from institutions the business never applied to, and a process whose entrance is itself the trap, because the only route to a firm answer is a formal application the project is not ready for.

Behind each fear sits the same condition. A business cannot weigh a cost it has not been shown, and the system currently shows it almost nothing until it is already committed. The remedy the evidence supports is earlier confidence: decision-grade indicative information at enquiry stage, with assumptions and confidence levels stated. Clearer attribution lets a customer read and challenge a quote. Uncertain demand also needs somewhere legitimate to go, so that a site that is years from applying can still be seen by the planners deciding what to build. Most of this concerns information and sequencing. Targeted support for upfront connection cost exposure is the main funding requirement, and the competitiveness evidence makes the case for it.

On this evidence, cost transparency is a condition for industrial electrification. The cases show that missing cost and timing information can push sites back toward fossil-fuel replacement or cause mobile investment to be prioritised elsewhere, while demand lost before application stays hidden from planners. Time and cost operate as a single quantity in these decisions: delay converts to internal cost, and a date that cannot be trusted destroys the value of any price attached to it.

The practical point is about timing. The end-to-end connections reform, ED3, the standing up of Regional Energy Strategic Plans, the National Energy System Operator's work on demand signalling and Ofgem's charging work are all live now, and each contains a slot where a recommendation in this report lands. Decisions taken in these processes over the next two years will set what an industrial customer can know, and when, for the rest of the decade. The cases in this report show what happens when that information arrives too late. The reform windows now open are the chance to move it earlier, and they will not stay open long.

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## 10 Annex: published DNO connection charging information by network group

Common to all six network groups under the Common Connection Charging Methodology in the Distribution Connection and Use of System Agreement (DCUSA): a high-cost threshold of £200 per kW for generation and £1,720 per kVA for demand; for demand connections, the DNO funds reinforcement up to the threshold and the customer pays reinforcement costs above it; and a cost breakdown is provided where connection charges exceed £20,000. For generation, reinforcement below the generation threshold is shared through the Cost Apportionment Factor. The following table records what each group has published beyond this standardised framework.

| DNO group                                         | Licence areas                                         | Current methodology statement                                              | Published indicative I&C pricing                                                                                                       | Actual quote data published                                                                                                     |
|---------------------------------------------------|-------------------------------------------------------|----------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------|
| <b>National Grid Electricity Distribution</b>     | West Midlands, East Midlands, South West, South Wales | Statement of Methodology and Charges, June 2026                            | Indicative price table; typical small business (up to 69kVA) about £6,000 excl. VAT; large HV and EHV connections price on application | Limited: historical quote-based dataset for high-volume, low-voltage on-street EV connections; no comparable larger I&C dataset |
| <b>Electricity North West</b>                     | North West England                                    | Statement of Methodology and Connection Charges, v5.9, effective June 2026 | Indicative table for 1 to 4 properties (inc. VAT) with a percentage quote breakdown; no larger I&C band published                      | None                                                                                                                            |
| <b>SP Energy Networks</b>                         | SP Distribution, SP Manweb                            | Statement of Methodology and Charges, November 2025                        | No price table; free budget estimate and free Quote+ optioneering across three capacity options; formal offer valid 3 calendar months  | None                                                                                                                            |
| <b>Scottish and Southern Electricity Networks</b> | SHEPD, SEPD                                           | SHEPD v1.47; SEPD v1.49 (June 2026)                                        | No price table; quick-estimate calculator and free budget estimate; feasibility study charged at £248 to £8,060 plus VAT               | None                                                                                                                            |

| <b>DNO group</b>          | <b>Licence areas</b> | <b>Current methodology statement</b>                                         | <b>Published indicative I&amp;C pricing</b>                                                                                                                                   | <b>Actual quote data published</b> |
|---------------------------|----------------------|------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------|
| <b>Northern Powergrid</b> | Northeast, Yorkshire | Connection Charging Methodology Statement, June 2026                         | Indicative table showing both "from" and average prices; small business £1,900 from / £18,100 average; large business £2,700 from / £78,500 average; EHV price on application | None                               |
| <b>UK Power Networks</b>  | EPN, LPN, SEPN       | Statement of Methodology and Charges, 2023 with later Ofgem-approved updates | Commercial tiers published; over four properties from £4,000 (average £10,250 per property); all larger tiers "provided after application review"                             | None                               |

Source: ADE: Demand Connections Costs project, published-information scan, July 2026. All figures exclude VAT unless stated. Prices are indicative and typically resolve to a price on application above small low-voltage connections.