Title: Decarbonisation Readiness **IA No:** DESNZ004(C)-23-ESNM **RPC Reference No:** RPC-BEIS-5247(1) **Lead department or agency:** Department for Energy Security and Net Zero **Other departments or agencies:**	**Impact Assessment (IA)** **Date:** 13/03/2023 **Stage:** Development/Options **Source of intervention:** Domestic **Type of measure:** Secondary legislation **Contact for enquiries:** electricity.security@beis.gov.uk
Summary: Intervention and Options	**RPC Opinion:** Informal: No rating provided

Cost of Preferred (or more likely) Option (in 2019 prices)			
Total Net Present Social Value	**Business Net Present Value**	**Net cost to business per year**	**Business Impact Target Status**
-£127m	-£127m	£8m	Qualifying provision

What is the problem under consideration? Why is government action or intervention necessary?

A large amount of new electricity generating capacity will need to be built to meet overall increased electricity demand and to replace aging capacity. We expect some of this capacity will be flexible unabated combustion generation to complement intermittent renewables. It is likely that during the assets' lifespan, the government will need to act to achieve Carbon Budget targets and net zero carbon emissions by 2050. There is a risk that such policy actions could affect the operation of these plants and they could become uneconomic to run before the end of their operational lifetime. Forced early closure of these plants could increase the overall costs of decarbonising the electricity system.

What are the policy objectives of the action or intervention and the intended effects?

The objective of the policy is to ensure that developers put plans in place so that newly built unabated high-carbon electricity generating plant can be decarbonised within their operational lifetimes. This will be through the low-carbon technologies which are expected to be available by retrofitting Carbon Capture and Storage (CCS) or converting to 100% hydrogen-firing. If successful, we would expect to see few unabated combustion plants closing before the end of their operational life, and more retrofitting to run on low-carbon technologies. We may expect a reduction in new build high-carbon projects where retrofitting is not feasible, but these should be replaced by decarbonisation ready projects, so we would not expect this to lead to security of supply issues.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

Option 1 – 'Do nothing'. Do not update the Carbon Capture Readiness (CCR) requirements.
Option 2 – Decarbonisation Readiness (DR) requirements. Update the requirements to remove the 300MW threshold, apply to refurbishing plants, apply to additional technologies and allow demonstration of hydrogen readiness (or any other decarbonisation technologies which may come forward in the future).
Option 3 – Remove the CCR requirements. There would be no obligation on developers to assess the technical or economic feasibility of retrofitting new build gas plant with low-carbon technology.

Option 2 is the preferred option as it would ensure developers have considered decarbonisation options for new build and refurbishing plant. This should lower the overall system costs of meeting Net Zero by capturing all new and refurbishing combustion plant and allowing flexibility for the most practical decarbonisation technology for the project to be used in this assessment.

Will the policy be reviewed? It will be reviewed. **If applicable, set review date:** pre-2030

Is this measure likely to impact on international trade and investment?		No		
Are any of these organisations in scope?	**Micro** Yes	**Small** Yes	**Medium** Yes	**Large** Yes
What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)		**Traded:**	**Non-traded:**	

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister: ____________________ Date: 09/03/23

Summary: Analysis & Evidence

Policy Option 1

Description:

FULL ECONOMIC ASSESSMENT

Price Base Year 2021	PV Base Year 2024	Time Period 25 Years	Net Benefit (Present Value (PV)) (£m)		
			Low:	**High:**	**Best Estimate:** £0m

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low		25		
High				
Best Estimate	0		0	**0**

Description and scale of key monetised costs by 'main affected groups'

This option is 'do nothing' so there would be no change in costs.

Other key non-monetised costs by 'main affected groups'

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low		25		
High				
Best Estimate	0		0	0

Description and scale of key monetised benefits by 'main affected groups'

This option is 'do nothing' so there would be no change in benefits.

Other key non-monetised benefits by 'main affected groups'

Key assumptions/sensitivities/risks	**Discount rate (%)**	

Summary: Analysis & Evidence — Policy Option 2 (Preferred option)

Description:

FULL ECONOMIC ASSESSMENT

Price Base Year 2021	PV Base Year 2024	Time Period 25 Years	Net Benefit (Present Value (PV)) (£m)		
			Low: -£180m	**High:** -£74m	**Best Estimate:** -£127m

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low		25	£5m	**£74m**
High			£12m	**£180m**
Best Estimate	0		£8m	**£127m**

Description and scale of key monetised costs by 'main affected groups'

There will be costs for affected businesses of additional permitting fees and the administrative burden of providing the assessments. Cost estimates are based on figures provided by the EA and stakeholders, they are projected in line with new build unabated gas capacity from BEIS Net Zero analysis. They vary from year to year depending on the volume of new build gas. High and low estimates are obtained by using the upper and lower values of permit costs provided by the EA as well as different BEIS projection scenarios.

Other key non-monetised costs by 'main affected groups'

There could be additional construction costs for affected projects in order for the site to be decarbonisation ready, but we have not been able to quantify these due to a lack of data and the site-specific nature of these costs. The additional administrative and construction costs could increase Capacity Market bids and, as the price in this auction applies to a large volume of electricity generating capacity, this could increase electricity system costs. However, we view it as likely these non-monetised costs will be small.

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low				
High				
Best Estimate				

Description and scale of key monetised benefits by 'main affected groups'

Other key non-monetised benefits by 'main affected groups'

There is the potential for reduced capital costs from fewer 'stranded assets' where plants are forced to close early due to decarbonisation measures and new build low-carbon options are built from scratch rather than making use of existing assets and retrofitting. Due to the nascency of decarbonisation technology and infrastructure, it is uncertain at this point how many plants may decarbonise and what the costs of doing so will be.

Key assumptions/sensitivities/risks — **Discount rate (%)** 3.5%

It is uncertain how costly and difficult it will be for businesses to comply with the requirements in terms of administration and construction. The impact is highly dependent on how much developers are already planning for decarbonisation in the absence of formal regulations. There is also a great deal of uncertainty over the volume and type of new build plant coming forward in the future, how many may choose to switch to hydrogen or CCS and what the costs of doing so will be.

A 25-year appraisal period has been used as many of the affected assets have an operating lifetime of 25 years.

BUSINESS ASSESSMENT (Option 2)

Direct impact on business (Equivalent Annual) £m:			**Score for Business Impact Target (qualifying provisions only) £m:**
Costs: 8	**Benefits:** 0	**Net:** 8	37

Summary: Analysis & Evidence

Policy Option 3

Description:

FULL ECONOMIC ASSESSMENT

Price Base Year 2021	PV Base Year 2024	Time Period 25 Years	Net Benefit (Present Value (PV)) (£m)		
			Low: £6m	**High:** £15m	**Best Estimate:** £11m

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low		25		
High				
Best Estimate				

Description and scale of key monetised costs by 'main affected groups'

Other key non-monetised costs by 'main affected groups'

If developers do not plan for decarbonisation, we could see more plants closing early and being replaced by new low-carbon plant at greater expense than from retrofitting existing plant, increasing overall system costs.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low		25	£0.4m	£6m
High			£1.0m	£15m
Best Estimate	0		£0.7m	£11m

Description and scale of key monetised benefits by 'main affected groups'

Administrative costs would fall as developers for new build unabated gas projects larger than 300MW would no longer need to comply with CCR requirements. This is likely to only affect a small number of plants, so savings are fairly low.

Other key non-monetised benefits by 'main affected groups'

Electricity system costs could fall in the short term as the lower regulation reduces administrative and construction costs of large new build gas plant. It could also remove the distortion of the 300MW threshold and encourage whatever size of plant is most cost efficient, reducing overall system costs.

Key assumptions/sensitivities/risks — **Discount rate (%)** 3.5%

The extent of this impact depends on the cost of ensuring plant are decarbonisation ready (in terms of location and size of site and the machinery used), whether developers will ensure they are decarbonisation ready in the absence of these requirements to protect their investment, and to what extent retrofitting low-carbon technology does become feasible in future.
A 25-year appraisal period has been used as many of the affected assets have an operating lifetime of 25

Evidence Base

Problem under consideration and rationale for intervention

In October 2021, Government announced its commitment to decarbonise the electricity system by 2035, subject to security of supply[1]. The recent British Energy Security Strategy (BESS)[2] reinforced Government's seriousness in going further and faster to reach this commitment and reach our targets for Carbon Budget Six (CB6) and net zero. As new unabated combustion power plants constructed during the next decade could be expected to be operational into the 2040s and 2050s, it is likely that at some point, during the lifespan of these assets, the government will need to act, to achieve Net Zero by 2050, by restricting carbon emissions and staying within the trajectory set by our Carbon Budgets.

To reduce the chances that such policy actions prevent these plants from earning an economic return on their investment (i.e. becoming "stranded assets"), it is important that developers put plans in place to ensure that these assets can be decarbonised in the future, through the low-carbon technologies which are expected to be available by retrofitting carbon capture and storage (CCS) or converting to hydrogen-firing. If many early plant closures coincide, there could also be a risk to security of supply as building new plants from scratch will take considerable time.

While some developers will already be putting such plans in place due to the existing "Carbon Capture Readiness" (CCR) requirements, developers with projects not falling under the CCR requirements may feel they have insufficient information or certainty over government policy to do so. This results in a coordination failure. The behaviour of others is critical for investors' choice of strategy as the more widespread the investment in a technology, the higher their payoffs become due to increased acceptance and maturity of a technology. As take-up of the technology increases there will be greater experience and confidence in the profitability of projects which should lower financing costs. Additionally, equipment manufacturing costs may decrease due to mass production and standardisation. Lowering costs in this way and keeping more options open for retrofitting will reduce the risk of some investments becoming stranded assets in the future.

The Decarbonisation Readiness (DR) requirements will support and standardise this process across the energy industry, as well as give the Government transparency and confidence on how industries are planning to decarbonise sites. Alongside other measures and announcements it aims to align investor expectations with Government ambitions and overcome this coordination failure.

This policy is an expansion of the existing "Carbon Capture Readiness" (CCR) requirements. CCR requirements were introduced in 2009 to ensure that planning consent in England and Wales was only granted to fossil fuel combustion power plants where developers could demonstrate it was technically and economically feasible that carbon capture technology could be retrofitted within the lifetime of the plant. This requirement only applied to prospective power plants sized at or above 300MW.

To ensure that all new build and refurbishing combustion power plants, regardless of size, have a viable route to decarbonisation we intend to expand the scope of the CCR requirements to include smaller fossil fuel plants as well as biomass, Energy from Waste (EfW) and Combined Heat and Power (CHP) plants. As we will also be expanding the scope to allow the demonstration of hydrogen conversion as well as CCS, we are renaming the requirements

[1] https://www.gov.uk/government/news/plans-unveiled-to-decarbonise-uk-power-system-by-2035

[2] https://www.gov.uk/government/publications/british-energy-security-strategy

"Decarbonisation Readiness" (DR) requirements. The expansion to DR will only apply in England[3] (existing measures will continue to apply in Wales).

This measure will affect almost all developers and investors involved in new build and substantially[4] refurbishing combustion plant in England. A limited range of exemptions for certain emergency back-up plants already exists within the Environmental Permitting Regime. Such plants are expected to run very infrequently and so it should be suitable for them to be excluded from DR too. We also propose to exclude all new build and refurbishing capacity which holds a Capacity Market[5] (CM) agreement or a Contracts for Difference[6] contract at the time that the DR requirements come into force (1 July 2024) to avoid adversely affecting security of supply or investments already made on the basis of CM agreements.

New gas plants larger than 300MW will be least affected as they would previously have needed to comply with the similar process of CCR requirements. Smaller plants as well as biomass, EfW and CHP plants will be brought into the scope of the requirements through this policy change. The requirements will impose administrative costs and additional upfront construction on affected plants, but could also benefit them through reduced costs for retrofitting to CCS or hydrogen in later years.

Description of options considered

Option 1 – Do Nothing

Under this option, the CCR requirements would remain as they are. They would only apply to new build fossil fuel plant larger than 300MW and require that the plant demonstrates the technical and economic feasibility of retrofitting carbon capture equipment.

This option would partly meet the desired outcome of increasing the preparedness of plants to decarbonise, but would have a fairly narrow scope so its impact could be limited. The 300MW threshold also creates a market distortion, by disincentivising the deployment of gas plants larger than 300MW, which tend to be more efficient.

Option 2 – Decarbonisation Readiness requirements

This option would rename the requirements to Decarbonisation Readiness (DR) requirements and make the following amendments:

1) Remove the 300MW minimum capacity threshold at which the requirements apply.
2) Move the DR requirements from the planning consent process to the environmental permitting process.
3) Introduce the option to comply through hydrogen conversion in addition to the retrofitting of carbon capture and storage (CCS) technologies.
4) Expand the scope to include biomass, Energy from Waste (EfW) and Combined Heat and Power (CHP) technologies which were previously excluded from CCR. The new requirements will also include substantially refurbishing plant as well as new build.

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[3] This matter is devolved; therefore, Wales, Scotland and Northern Ireland have their own arrangements

[4] This is set out in Schedule 24 to the Environmental Permitting (England and Wales) Regulations 2016 https://www.legislation.gov.uk/uksi/2016/1154/contents/made

[5] The Capacity Market is designed to ensure sufficient reliable capacity is available by providing payments to encourage investment in new capacity or for existing capacity to remain open. The latest auction was for Delivery Year 2025/26.

[6] CFDs are 15 year private law contracts between low-carbon generators and the Low Carbon Contracts Company. CFDs stabilise revenues for generators at a fixed price level, set by the Government (the 'strike price'). Generators receive revenue from selling their electricity into the market as usual, but when the market reference price is below the strike price they receive a top-up payment. If the reference price is above the strike price, the generator must pay back the difference.

Applying stringent tests to the widened group of affected plants carries risks such as preventing smaller plants or certain technologies from coming forward. Given the nascency of both CCS and hydrogen infrastructure and policy, the tests will be less rigorous at the outset and become more rigorous over time, as certainty around the technology and policy context increases. The economic feasibility test and hydrogen fuel access test will not be mandatory to pass in the short term. Plants constructed during or after 2030 which secure their DR permit as hydrogen ready will be required to install generation equipment that is capable of firing 100% hydrogen from the point of initial operation. This is when OEMs have indicated such equipment will be readily available on the open market. The regular review of DR requirements will be used to assess whether hydrogen and CCUS infrastructure has improved sufficiently to justify strengthening the tests.

This option would capture more generators than Option 1 and allow the generators to demonstrate readiness to convert to hydrogen-firing as well as CCS, which may be more appropriate for certain types of plant.

Option 3 – Remove the CCR requirements

This option would remove the existing CCR requirements. There would be no obligation on developers to assess the technical or economic feasibility of retrofitting new build gas plant with low-carbon technology.

This option would not meet the outcome of increasing the preparedness of plant to decarbonise beyond what market participants currently think is beneficial to do.

Policy objective

The intention of DR is to provide a clear pathway for new build and refurbishing high-carbon combustion power plants to decarbonise. This is to reduce the risk of coordination failure and the potential security of supply issues caused by many early plant closures. This risk arises because the behaviour of others affects developers' planning and decision making. As take-up of the technology increases, investors can learn from earlier projects and financing costs should fall due to lower perceptions of risk. Additionally, equipment manufacturing costs may decrease due to standardisation and mass production. DR signals the Government's commitment to the deployment of hydrogen to power and CCS, and ensures plants are in the best possible position to take advantage of decarbonisation opportunities when they arise.

This lowers the risk of creating 'stranded assets' (whereby future policy actions and/or technological developments prevent these plants from earning an economic return on their investment) and, therefore, reduces the costs associated with decarbonising the power sector. The DR requirements will support developers with their plans for maximising the potential to decarbonise their assets in the future. We expect that some developers will already be doing this planning, given the net-zero imperative. The DR requirements will support and standardise this process across the energy industry, as well as to give the Government transparency and confidence on how industries are planning to decarbonise sites.

If successful, we would expect to see few high-carbon plant closing before the end of their operational life and to see some retrofitting to run on low-carbon technologies. We would also expect to see DR-ready plants converting to their chosen decarbonisation technology. We may expect a change or reduction in new build high-carbon projects where retrofitting is not feasible but, if the policy is successful in not overburdening developers, we would not expect this to lead to security of supply issues as they would be replaced by projects where retrofitting is feasible.

Summary and preferred option with description of implementation plan

Option 2 is the preferred option. It will be given effect through secondary legislation and come into effect in July 2024.

Removing the 300MW threshold alongside an expansion in the technologies within scope would ensure that as many new build and refurbishing combustion power plants as possible are covered by the requirements. It will eliminate the market distortion between smaller and larger plants, and ensure developers bring forward optimal sized plant which can provide for a more cost-efficient system overall.

Moving the DR requirements to the Environmental Permitting Regulations (EPR) allows us to capture previously consented projects and refurbishing plant in the DR update and make sure they are only built or refurbished if they are decarbonisation ready. EPR is a more flexible regime than planning and so can be amended more readily to respond to future market or technical developments. Tried and tested systems are already in place for compliance monitoring, inspection & audit, reporting & enforcement, and paying permitting fees & charges.

However, implementing through EPR may increase investors' perception of risk, due to the possibility of changes to future permit requirements, thus making projects more expensive. It also comes later in the construction process than planning consent. For example, developers must decide how much space on a site is required to accommodate additional equipment needed for carbon capture or hydrogen-firing in the future when purchasing land and obtaining planning consent, before having formal confirmation from the EA that this is sufficient to meet their DR requirements.

To mitigate the risk of any discrepancies between planning consents and permit requirements, we encourage developers to attain their environmental permit in parallel to the consenting and construction of the site. We believe that any increase to investors' perception of risk resulting from implementing through environmental permitting should be manageable, given that DR is being targeted at new build and refurbishing plants only, which would already have to seek a new or variated environmental permit. And any changes to DR would of course require further consultation.

Introducing options to comply through conversion to hydrogen-firing provides greater flexibility of decarbonisation options. Hydrogen conversion may be more suitable for smaller combustion plant and/or 'peaking' combustion power plants[7] for which CCS conversion would be potentially impractical due to either economic or technical constraints.

Including substantially refurbishing plant within scope will eliminate the risk of unintentionally incentivising developers to pursue refurbishing existing projects as a way of avoiding the DR requirements, which would undermine the delivery of our policy objectives.

Biomass, EfW and CHP plants will be captured by the DR requirements as well as fossil fuel combustion plants. These plant types were previously implicitly excluded from the scope of the CCR requirements due to their size and improved environmental performance compared to unabated fossil fuel combustion power plants. We are including them in the DR requirements because, when considered in the context of our ambitious decarbonisation targets for the electricity system, they may still emit significant amounts of carbon. This should support the rapid decarbonisation of the electricity system and complement existing technology-specific decarbonisation policies.

The Government intends to require plants to review their requirements every two years after their permit is issued in continuation of the current CCR requirements. Whilst hydrogen and CCS technologies and infrastructure are relatively nascent at present, we expect advancement

[7] Power plants that generally run only for a small number of hours when there is high demand for electricity

and deployment to rapidly increase, particularly in the 2030s. It is therefore important developers are regularly reviewing their plant's compliance with DR requirements and assessing whether a viable decarbonisation option has become available, for example the connection of a nearby industrial area to a hydrogen network.

If the two-yearly review identifies a technical or economic barrier to retrofitting the developer's chosen decarbonisation technology, we do not believe this should necessarily be treated as non-compliance with the permit. Both hydrogen and CCS are evolving technologies and a solution may emerge in time. Developers, however, should consider any identified barrier carefully and explore solutions accordingly. The review would only lead to a developer being considered in breach of their permit if any action they had taken had led to the emergence of the barrier, for example, if they fail to maintain control of the space set aside for carbon capture equipment or equipment associated with hydrogen storage or transport.

Government recognises the two-yearly review places additional burdens on developers; however, the review process will be relatively light touch focusing on reviewing the most significant aspects of DR requirements to assess whether it would be viable for the plant to be decarbonised in the near future. This would include assessing whether viable transport and storage infrastructure is being developed close to the plant and whether the chosen technology remains the most suitable decarbonisation option.

The EA would be responsible for the implementation, operation and enforcement of the requirements in England. Government proposes to introduce a statutory five-year review of DR requirements including a public consultation. This period would strike a balance between keeping pace with the rapidly evolving technologies of hydrogen and CCS, whilst allowing meaningful change in those technologies which could inform potential amendments to the requirements

Monetised and non-monetised costs and benefits of each option (including administrative burden)

Option 1 – Do nothing

Plant level costs and benefits

Administrative costs remain at the current level and only affect new build natural gas-fired developments larger than 300MW.

Design and construction requirements remain at the current level and only affect new build gas-fired developments larger than 300MW.

BEIS illustrative Net Zero consistent scenarios[8] suggest we could see around 25-35GW of new build natural gas-fired capacity between 2022 and 2035. Around 75% of new build gas capacity winning long-term agreements in the Capacity Market has been from units smaller than 300MW. This suggests that if the regulations are left as they are there will be a high volume of new build gas plant that will not need to demonstrate the feasibility of decarbonisation, which risks them being poorly placed to adapt to measures such as strengthening carbon prices or emissions limits that are required to decarbonise the system.

This may lead to closures before the end of their operational lifetime and additional capital spending on the construction of new build hydrogen or CCS plant rather than lower spending retrofitting existing assets. It is unclear what proportion of developers would consider decarbonisation feasibility in the absence of regulations; if this is already part of many investment decisions then the impact of not expanding the regulations would be small.

[8] https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

There are a small number of hydrogen and CCS power plant being developed, such as Saltend[9] and Keadby[10]. Feedback from the Call for Evidence[11] suggests that some developers are incorporating a decarbonisation strategy into their investments but that, due to the nascency of these decarbonisation technologies, there is a great deal of uncertainty and it is difficult for developers to plan for with any accuracy. Without industry-wide guidance and regulation, planning is likely to be irregular and inconsistent.

Option 2 – Decarbonisation Readiness requirements

Administrative Costs

Under this option, the broader scope of the requirements is likely to increase businesses' administrative costs.

There will be additional permitting costs in the initial permit application fee and ongoing compliance costs associated with DR, due to the increased burden on the EA. Permitting charges vary considerably depending on the size and technology of the plant but the EA have produced rough estimates for the additional costs based on current permitting officer time spent on CCR assessments and adjusted for the DR changes.

To avoid disproportionate admin burdens, the EA expect to have a lighter touch approach for smaller plant, probably in a similar way to many Medium Combustion Plant having standard rules permits which are less costly. Based on numbers of permit applications in recent years, the EA estimate the additional cost to be less than £1m a year. However, as electricity demand rapidly increases and existing plant retire over the coming years, the number of applications could change considerably from current levels.

Projecting these costs forward in line with new build natural-gas-fired capacity (as these make up the vast majority of affected plant) from BEIS illustrative Net Zero consistent scenarios suggest that total permitting and compliance costs across all applications could be up to £6m in some years. However, the projected scenarios are only indicative of what a future energy generation mix may look like rather than prescriptive forecasts. There remains much uncertainty, including for example about the pace of innovation in the market, demand levels, the technical feasibility of some technologies, and the investment decisions of electricity generators.

The proposed DR requirements are fairly similar to the existing CCR requirements so we do not expect much change in administrative costs for developments that would fall within the scope of CCR requirements.

Developments that will be affected due to the extended scope of the requirements will face administrative costs of providing the DR assessments either in-house or through contracting out to consultants. Plants affected include new build natural gas plant smaller than 300MW, refurbishing natural gas plant and new/ refurbishing projects with other carbon-emitting technologies such as biomass, EfW and CHP. Based on feedback from stakeholders we estimate that this may cost around £25,000-£35,000 for large projects demonstrating compliance with CCR requirements. We have not received any feedback on likely costs for smaller projects so have assumed costs will be around 5 to 6 times the cost to the EA of checking the permit (in line with large projects). We have not received any feedback on

[9] https://www.equinor.com/energy/h2h-saltend

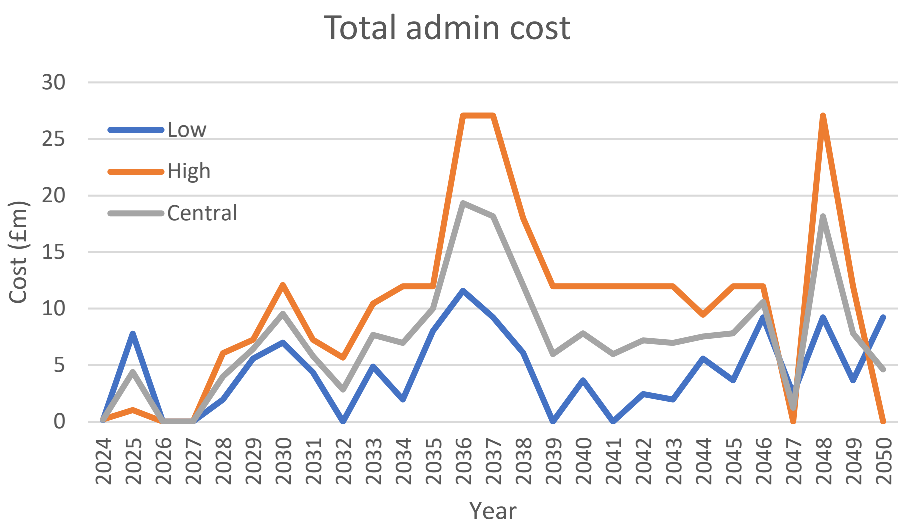
[10] https://www.equinor.com/news/archive/20210408-sse-thermal-hydrogen-ccs-humber

[11] https://www.gov.uk/government/consultations/decarbonisation-readiness-call-for-evidence-on-the-expansion-of-the-2009-carbon-capture-readiness-requirements

familiarisation costs but these are expected to be small in comparison to the DR assessments themselves. Again these costs have been projected in line with estimated future natural-gas fired capacity.

Estimates of total administrative costs (both for developers and the EA) vary considerably from year to year and across different potential energy mixes due to the range of new build gas capacity. Figure 1 shows our low, high and central estimates. The average annual cost in the central case is £8m.

Figure 1



Plants may seek to recover these costs by passing them on to their Capacity Market bids, which could increase CM auction costs. These are recovered directly from consumer bills and therefore lower earners may be disproportionately affected. However, for large plant the additional estimated costs represent less than 1% of pre-development and construction costs[12] of a new build OCGT or reciprocating engine, so it is likely that the effect of additional administrative costs on CM bids, and therefore any distributional impact, will be negligible.

Again, this impact is highly dependent on how many developers are already carrying out feasibility studies for decarbonisation in light of net zero targets. The guidance provided alongside the DR regulations should assist developers in likely site requirements, but the impact may be limited until there is greater certainty on infrastructure and market frameworks for CCS and hydrogen.

Construction costs

This policy may increase upfront construction costs for new build and refurbishing plant due to the additional requirements to demonstrate decarbonisation readiness. For example, we have seen from CCR cases that CCUS-ready plant require a larger site footprint than a natural gas plant in order to house the additional equipment for carbon capture. Any additional construction costs incurred due to CCR are private information held by individual developers, so to inform our analysis we draw on two technical reports commissioned by BEIS to update and expand the evidence base that is used to define the requirements for demonstrating decarbonisation via hydrogen or CCS. We would welcome any additional evidence that can be provided in response to this consultation.

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[12] BEIS Electricity Generation Costs 2020 (https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020)

Fossil fuel fired plant larger than 300MW already have to comply with CCR so we do not expect additional construction costs for them. They may even incur lower costs if it is more straightforward for them to demonstrate hydrogen readiness rather than CCS. We expect most gas-fired plant smaller than 300MW to demonstrate hydrogen readiness. The CCS technical report's case studies found, '*The OCGT conversion [to CCS] clearly incurs significant incremental cost… compared to fitting the post-combustion capture plant to similar CCGT*' and hydrogen generation can be ramped up and down very quickly which may be more compatible with a small peaking plant's business case.

The findings of the hydrogen technical report suggest that a hydrogen-ready site will probably not incur significantly different construction costs to a standard natural-gas fired site. The site footprint may need to be slightly larger due to an increase in hazardous zone sizes, hydrogen supply infrastructure, or requirements to set aside space for Selective Catalytic Reduction (SCR) equipment to reduce NOx emissions from hydrogen burning. The footprint requirements vary depending on the plant, in most cases they estimate that the additional footprint for hydrogen infrastructure and SCR is less than 1% of the footprint of the base plant, and less than 2% in the worst case.

Hydrogen ready plant are likely to require some different materials and equipment in order to be compatible with hydrogen in future. Pipe materials need to be specified and sized to accommodate hydrogen (or enough space should be left in order to run hydrogen pipes in parallel) and from 2030 our proposal is for plant demonstrating hydrogen conversion readiness to install 100% hydrogen firing compatible generation equipment from the point of initial operation (they will also be able to fire natural gas). The technical report finds that '*The consensus across the manufacturers of power generation equipment appears to be that new, purpose-built 100%-hydrogen fired equipment cost should be similar to that for natural gas with up to approximately 10% cost difference. Current industry sentiment indicates that overall project CAPEX for new-build 100%-hydrogen fired equipment will be comparable to that for natural gas equipment.*' Therefore, we do not expect large increases in construction costs for hydrogen-ready plant, perhaps up to 10% of their equipment cost.

Plant such as biomass and EfW units (as well as any fossil fuel plant preferring the CCS route to hydrogen) demonstrating carbon capture readiness may face additional construction costs, mainly from the increase in site footprint due to the need to install capture equipment in addition to the generation technology. The cost of this additional land is very difficult to estimate as it will be site specific. However, for the case studies covered in the technical report, additional land requirements are less than 0.5% of total capital costs for retrofitting a plant, so it is likely that this cost will be very small relative to other capital expenditure.

These upfront investments should reduce the costs for retrofitting hydrogen and CCS in future. For example, if a plant has installed a hydrogen-ready turbine it will not need to install new generation equipment.

It is uncertain how many plants will decide to retrofit to either hydrogen or CCS, this will be highly dependent on the roll out of infrastructure for hydrogen and carbon transport and storage. The BEIS illustrative Net Zero consistent electricity demand and generation scenarios mentioned in the previous section suggest there could be 20-26GW of hydrogen-fired capacity and 13-23GW of CCS capacity by 2050. There is currently around 40GW of natural gas-fired capacity on the system, so the figures suggest there could be considerable scope for retrofits. However, due to a substantial increase in projected electricity demand, the scenarios also estimate there could be 55-105GW of natural gas-fired capacity on the system in 2050, so there could still be a role for natural gas if its operation on extremely limited running hours is more economical than a CCS or hydrogen business model. Again, the scenarios are only indicative and there is a great deal of uncertainty around the future generation mix.

Electricity system impact

Most of the new build unabated gas plants winning agreements in the Capacity Market have been smaller than 300MW and therefore haven't had to comply with the CCR requirements. Around 75% of the 6GW of new build gas capacity winning long term agreements has been smaller than 300MW.

The 300MW threshold is creating a market distortion by incentivising the deployment of peaking plants smaller than 300MW. In the T-4 auction for Delivery Year 2024/25[13] seven Capacity Market Units sized at 299-299.9 MW prequalified for the auction (about a quarter of pre-qualified new build gas capacity). This could be because the administrative costs of complying with CCR are too high, but it is more likely that peaking plants are unable to pass the economic/ technical feasibility tests for CCS as OCGT conversion to CCS incurs significant incremental costs compared to a CCGT plant and CCS plant cannot be quickly ramped up and down. Removing the distortion of the 300MW threshold would encourage whatever size of plant is most cost efficient, reducing overall system costs.

As set out above, applying the requirements to new build and refurbishing combustion plant smaller than 300MW may increase the costs of these plant through administrative burden and construction costs. It may also reduce the number or change the type of new build projects coming forward. This is part of the intent behind the policy i.e., to ensure that projects which are not decarbonisation ready are not taken forward. This may increase electricity system costs if costs are passed on through Capacity Market bids and/or cheaper plant are discouraged from building. We expect this impact to be limited, as prudent developers should be planning for decarbonisation anyway and, as set out in previous sections, we expect the costs of this policy to be fairly small for most affected plant.

Offsetting these higher costs is the potential for reduced capital costs in future from making use of existing assets and retrofitting CCS or hydrogen. DR supports this by identifying and preventing issues that could make retrofitting impossible (such as an insufficient site footprint), as well as cutting the cost of retrofits through simplifying the logistics of the work and reducing the amount of equipment that needs replacing. For example, natural gas pipes could be specified and sized to be able to accommodate hydrogen, or wider piperacks and sleeper ways could be used such that hydrogen pipes can be laid in parallel, avoiding the need for a lengthy outage.

Greater opportunity for retrofitting avoids 'stranded assets', where plants are forced to close early due to decarbonisation and new build low-carbon options are built from scratch. Again, these lower capital costs could be passed on to consumers through lowering Capacity Market bids and the cost of ensuring security of supply.

Option 3 – Remove the CCR requirements

Administrative costs

Administrative costs would fall as developers for projects larger than 300MW would no longer need to comply with CCR requirements. The extent of this impact depends on how many of these projects there are and how much analysis developers would continue to put into decarbonisation readiness without the regulations.

Since 2018 there have only been 2-4 projects each year requiring a CCR assessment. Using the same assumptions on administrative cost of complying with CCR/ DR as for Option 2, and projecting in line with new build gas plant over 25 years, cost savings would be less than £1m a

[13] Three of these units were awarded long term agreements at the auction, another three went on to prequalify for the 2025/26 T-4 auction where one was successful

year on average. We have not received feedback on familiarisation costs, and while likely to be small, these may likely reduce the potential savings further.

Electricity system costs

Electricity system costs could fall in the short term as the lower regulation reduces administrative and construction costs of large new build gas plant. The construction cost savings are uncertain and will vary from site to site but could be outweighed in the long term by these plants closing early and being replaced by new low-carbon plant at greater expense than from retrofitting existing plant. Removing the distortion of the 300MW threshold would encourage whatever size of plant is most cost efficient, reducing overall system costs.

The extent of this impact depends on the cost of ensuring plant are decarbonisation ready (in terms of location and size of site and the machinery used), whether developers will ensure they are decarbonisation ready in the absence of these requirements in order to protect their investment, and to what extent retrofitting low-carbon technology does become feasible in future.

Direct costs and benefits to business calculations

There are no other direct impacts on businesses beyond those identified in the previous section.

Risks and assumptions

The main risk to this analysis is how costly and difficult it will be for businesses to comply with the requirements. There needs to be a balance between ensuring that the DR assessments are achievable for developers and do not limit investment in firm dispatchable generation, whilst also being meaningful in ensuring combustion power plants have a viable route to decarbonisation. If the costs to business are higher than assumed in this analysis then there could be significant impacts on the volume of new build plant investment which could reduce security of supply.

We have based our cost assumptions on permitting figures provided by the EA, figures from consultants on potential DR report costs, and technical reports for hydrogen and CCS plant. These sources are the best evidence we are aware of but welcome any other evidence that can be provided by respondents to the consultation.

There is also a great deal of uncertainty over the volume and type of new build plant coming forward in the future and how many may choose to switch to hydrogen or CCS. We have used the latest BEIS scenarios for Net Zero pathways, which are only illustrative but are viewed as plausible and generated using a long-standing BEIS model for the electricity system (the Dynamic Dispatch Model[14]).

Impact on small and micro businesses

ONS business data[15] indicates that 4,585 out of 4,620 enterprises in the ‘Production of electricity’ sector had fewer than 50 employees in 2021. So around 99% of all enterprises in that sector would be classed as small or micro businesses (SMBs) as defined in the Better Regulation Framework guidance. It is not possible to quantify exactly how many SMBs would be affected by this measure and apportion costs accordingly as we do not forecast new build plant by company size however, given their prevalence in the sector, it is likely that this measure would affect many SMBs.

To get a better sense of the types of businesses affected by this measure, we have looked at the parent companies listed for new build gas and EfW plant smaller than 300MW prequalifying

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[14] https://www.gov.uk/government/statistics/the-dynamic-dispatch-model-a-fully-integrated-power-market-model

[15] https://www.ons.gov.uk/businessindustryandtrade/business/activitysizeandlocation/datasets/ukbusinessactivitysizeandlocation

for the last Capacity Market auction. According to accounts filed with Companies House for the top 10 companies by capacity entered (accounting for 84% of relevant capacity entered), only 2 of them had more than 50 employees. 7 of the businesses were intermediary holding companies with no employees or only directors listed as employees.

Given that intermediary holding companies are common in the electricity sector, it may be that the employee classification is inappropriate, and it would be better to look at turnover or assets. However, as the measure mostly affects new build plant, if a holding company is set up specifically for a plant that isn't constructed or operational yet, then it is likely they would have little in the way of turnover or assets and would still be classed as a small enterprise.

Due to the prevalence of SMBs it would not be possible to exempt them from these regulations and still achieve the policy objectives. To try and mitigate any disproportionate administrative burdens, the EA are proposing to have lighter touch assessments for smaller plant. It seems likely that small businesses are more likely to be investing in smaller plant than larger plant so this mitigation should help reduce the impact on SMBs.

Wider impacts (consider the impacts of your proposals)

This measure reinforces the Government's message set out in the Net Zero Strategy[16] that our ambition is for the power sector to be Net Zero by 2035 (subject to security of supply) and should give investors greater certainty in the Government's decarbonisation commitment. This could increase the confidence of manufacturers of power generation equipment and lead them to invest more in CCS and hydrogen technology development, spurring innovation and cost reductions.

A summary of the potential trade implications of measure

This measure does not introduce different requirements for businesses from different countries and does not have an impact on international trade or investment.

Monitoring and Evaluation

We propose to add 'Decarbonisation Readiness' to the list of directives in Regulation 80 of the Environmental Permitting Regulations which requires the Secretary of State to carry out a review at intervals not exceeding five years. This will ensure the new arrangements are regularly monitored and evaluated.

The review would be based on similar reviews, such as the Capacity Market review, arising from the Electricity Market Reform (EMR). The main questions the review would aim to address are:

- How has DR performed against its objectives?
- Do the DR objectives remain appropriate?
- Does the legislation remain appropriate?
- Should the hydrogen fuel access test be made mandatory to demonstrate?
- Should the economic tests for hydrogen and/or CCS readiness be made mandatory to demonstrate?
- Is the Regulator's guidance suitable?
- How do the actual costs of the legislation compare with the ex-ante estimates?

If the policy is successful, we would expect to see few high-carbon plant closing before the end of their operational life and more retrofitting to run on low-carbon technologies as set out in their DR assessments, i.e. a reduction in stranded assets. We may expect a reduction in new build

[16] https://www.gov.uk/government/publications/net-zero-strategy

high-carbon projects where retrofitting is not feasible, but these should be replaced by decarbonisation ready projects, so we would not expect this to lead to security of supply issues.

The main factors that are likely to impact the success of the policy are:

- The development and roll out of hydrogen and CCS strategies and infrastructure
- Whether the guidance is sufficiently clear and comprehensive to assist developers in becoming decarbonisation ready
- Whether the requirements strike a balance between being meaningful and creating barriers to entry
- Whether the additional costs and time involved deter investment in new build plant or introduce any market distortions such as incentivising a particular size of plant or technology type beyond what would be required to ensure decarbonisation readiness of new plant

If there were significant developments in decarbonisation technologies or such little new build plant coming forward that it threatens security of supply, we would review the policy sooner than 5 years. Security of supply issues would become apparent through the annual Capacity Market prequalification process if we saw a low volume of new build capacity prequalifying and a small pool of capacity bidding into the auction relative to the target.

Given that we expect this measure to be fairly low impact, we view a proportionate approach would be to carry out the evaluation in-house without the requirement for bespoke monitoring data. There are costs and benefits we have not been able to monetise in this assessment due to lack of data (such as additional construction costs) and we hope to inform these at the evaluation stage through stakeholder engagement once developers have experience of the new scheme in practice. We may also be able to qualitatively infer whether construction costs are having an impact, for example by checking for a reduction in new build projects. Likely data requirements are set out below:

- Stakeholder views will be gathered through a public consultation and analysed alongside the monitoring evidence.
- Plant connections and retirements by size and technology type can be monitored through the Transmission Entry Capacity (TEC) register and Embedded Capacity Registers
- The pipeline of large new build projects can be monitored through the National Infrastructure Planning Database. Smaller projects may be monitored through Capacity Market registers, however not all new small plant will participate in the CM so this is not a perfect measure.
- Refurbishing plant numbers and capacity (by size and technology type) can again be monitored through the CM, but this may not capture all refurbishing projects
- EA permit application numbers and costs
- EA to collect data on the number of applications passing or failing the DR assessments (including information on plant capacity and technology type)

Our theory of change which would be used in the evaluation of this measure is set out in

Figure 2 below. The main stakeholders involved in the measure are

- Developers – any developers of affected projects will need to comply with the new requirements
- The EA – the requirements will move to the Environmental Permitting Regulations and the EA will be responsible for approving applications and ensuring compliance
- The Department for Energy Security and Net Zero will lead on policy design and monitor the impact of the measure

There are multiple changes planned to the regulations. Moving them from the planning process to environmental permitting provides greater flexibility to amend them in response to future market or technical developments. Similarly, starting with a lighter touch approach to the requirements then regularly reviewing and strengthening them when there is greater certainty around decarbonisation pathways will lead to the regulations being better aligned with market conditions. This should make the regulations as effective as possible for supporting decarbonisation planning (aiding the decarbonisation agenda) while encouraging innovation and minimising any adverse impact on investment (which could affect security of supply and consumer costs).

The measures are being expanded to plants smaller than 300MW, refurbishing plants and additional technology types. This is to remove distortions from the current system that could have unintended incentives for certain types of plant, as well as to ensure that as many carbon emitting plants as possible have decarbonisation plans in place. This should prevent capital being spent on new or refurbishing plants where there are significant barriers to decarbonisation and provide a level playing field for plants where decarbonisation is feasible. This should lead to the most cost-effective rollout of new build plant that is in line with our decarbonisation ambitions.

The regulations will also be expanded to allow the option of demonstrating hydrogen readiness in recognition that CCS is not appropriate for all types of plant, and the development in hydrogen technologies since the original CCR requirements were put in place. The flexibility in decarbonisation option should avoid unnecessarily preventing investment in new build projects where CCS is not a viable option and encourage consideration of business models involving hydrogen. This should minimise adverse effects on investment (which could affect security of supply and consumer costs) and encourage planning for hydrogen conversion (helping to decarbonise the power sector).

Figure 2