Adequacy assessment and analysis of potential solutions for the Netherlands

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CONFIDENTIAL

Content

1.

Introduction

1.1

Context and objectives of the study

The aim of this study is 1) to expand TenneT's analysis of the Dutch adequacy outlook and 2) analyse the merits of different potential solutions

Introduction and context

In May 2025 **TenneT** published its latest **Monitor *Leveringszekerheid* ("MLZ25")**[1] in which the Dutch resource adequacy is assessed for the years 2030, 2033 and 2035. The report finds that up to and including 2030 the resource adequacy in the base scenario remains within the 4-hour Loss of Load Expectation ("LOLE") norm but after 2030 the situation rapidly deteriorates, i.e. 2033 and 2035 show a significant exceedance of the LOLE norm, with respectively 12.6h and 9.2h per year.

The MLZ25 results slightly deviate from the most recent **European Resource Adequacy Assessment ("ERAA")**[2] which found a LOLE of 7.8h in 2028, 5.4h in 2030 and 6.3h in 2035. TenneT states that the difference between the two analyses are explained by a set of alternative Dutch-specific assumptions.

After the publication of MLZ25, the **Minister of Climate Policy and Green Growth ("KGG")** confirmed that her cabinet will decide on the introduction of a mechanism[3] to mitigate adequacy concerns in the first half of 2026.

Objectives of the study

The objective of this study is to provide policymakers with a deeper assessment of the Dutch adequacy situation and to evaluate the strengths of various potential solutions. The study is organised in two parts:

1. Analyse the **Dutch adequacy situation** for 2030, 2033 and 2035 by **expanding the MLZ25 report.** To that extent, we calibrate our power system model using the same assumptions as TenneT and run **additional sensitivities**. We also evaluate the required procurement volumes of different technologies to close the resource adequacy gap.

2. Assess the merits of **different options to mitigate concerns around the Dutch adequacy situation extending the MLZ25 report.** We model the **economic impact** of two capacity remuneration mechanisms ("CRMs"): a **centralised market-wide capacity mechanism** versus a **strategic reserve.** We focus on these two types of CRMs because they are:
   - the most widespread across Europe to address adequacy concerns, and;
   - described as the two most relevant potential solutions to be analysed by both the KGG and the Dutch regulator ("ACM").[4]

__Note:__ (1) TenneT, Security of Supply Monitor 2025, Monitor Leveringszekerheid (link); (2) ENTSO-E, ERAA 2024, (link); (3) Dutch Ministry of Climate Policy and Green Growth, Security of supply, 15 May 2025 (link); (4) ACM, Resource adequacy and the potential role and design of capacity remuneration mechanisms, 26 March 2025 (link).

1.2

Executive summary

Key messages of our study on adequacy concerns and potential solutions in the Netherlands

1. Our modelling of the interconnected Dutch power system completes the findings from TenneT: the Netherlands is facing significant issues with resource adequacy in the early 2030s.
2. Only relying on targeted procurement of demands-side response and/or storage to close the adequacy gap is likely neither sufficient nor cost effective.
3. There is a trend in the EU to shift from strategic reserves toward centralised market-wide capacity mechanisms to address evolving adequacy concerns and deliver needed investments.
4. A capacity market has several advantages over a strategic reserve in the specific Dutch context– most importantly only a capacity market enables the required investments, and hence is a structural long-term solution.
5. Implementing an SR or CM would enhance welfare over the status quo, with benefits in the same range but potentially higher for a CM depending on the specific design choices.
6. Considering the severe risk of adequacy concerns and welfare benefits of an intervention, we recommend the introduction of a capacity market…
7. … without delay as the costs for being too early are much lower than being too late.

Evolution of supply and demand drivers creates structural adequacy concerns in the Netherlands in the early 2030s

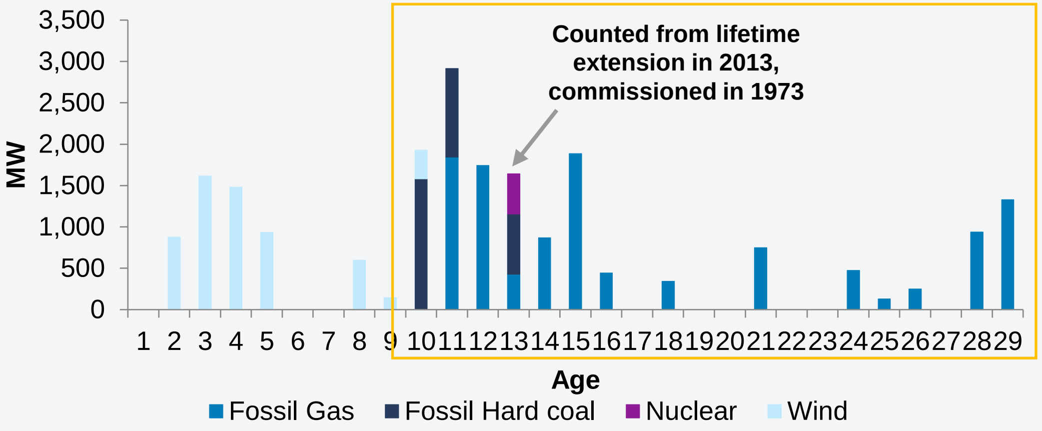
An uncertain adequacy outlook in the Dutch Power System

- **Coal-fired generation** is foreseen to **exit** by the end of 2029 at the latest, and the economics of the **aging gas-fired fleet** are increasingly uncertain due to **reduced running hours** as renewable penetration increases.
- **Entry of merchant dispatchable capacity** is commercially challenging due to an increasingly **risky investment environment**. The last final investment decision ("FID") for a thermal generator in the Netherlands was made in 2010.
- Additional **supply uncertainty related to external factors** is added by:
  - **Neighbouring countries' adequacy situations** remain uncertain (especially Germany) as significant decommissioning is expected, and the required investments may be delayed.
  - The timing of **commissioning important interconnectors** ("ICs") such as Lionlink (1.8 GW) with Great Britain ("GB") is uncertain.
  - TenneT's MLZ25 relies on an important role for **long-duration energy storage ("LDES")** in the Dutch system in the early 2030s while its technology readiness is uncertain.
- At the same time, **electricity demand is expected to grow** with electrification of end uses, but the pace of growth remains **uncertain**.
- These structural drivers combined create **substantial risks for adequacy** in the Dutch power system in the early 2030s.
- While we focus in this report on the 2030-2035 horizon, the **adequacy concern is not expected to be temporary** but rather a more permanent feature of the power system calling for a structural solution for the next decades to come.

Structural drivers impacting adequacy concerns

	Structural drivers	Impact on the adequacy situation
1	Coal exit by the end of 2029, uncertain commercial outlook for aging thermal fleet	Likely exit of important share of existing thermal capacity
2	Highly risky investment environment for entry of merchant dispatchable capacity	Very unlikely entry of any merchant dispatchable capacity
3	Uncertain German capacity expansion, timing new interconnection with GB and readiness of innovative technologies	Additional supply uncertainty that is largely out of control of NL
4	Expectations of rising demand in NL	Increased need for extending existing capacity and new entry

Capacity by age and technology in the Netherlands ("NL") as of 2025



A perfect storm of risks and uncertainties undermines the ability of an energy-only market to deliver the needed investments in firm capacity

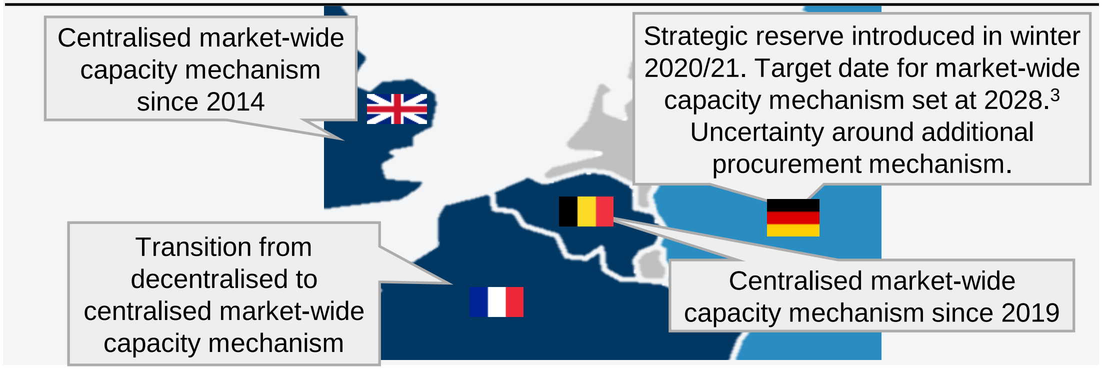
Investment risk factors in the Dutch Power System

- Stay-in-business and new investment decisions are significantly complicated due to increasing uncertainty in the Dutch power system; concrete risk factors in addition to business-as-usual market risks include for example:
    - **Increasingly volatile wholesale market prices** driven by rising shares of renewables including the risk that policymakers would **intervene when prices spike** (as witnessed during the European energy crisis).
    - **Rising gas network tariffs** and the potential introduction of **injection tariffs for electricity**.
    - **Uncertain decarbonisation requirements** for the thermal fleet considering the 2035 target to decarbonise the entire power sector.
    - Uncertainty around the announced **nuclear phase-in in 2040** and the potential introduction of **other low-carbon procurement schemes** (e.g., for storage).
    - **Uncertainty around the degree of the anticipated demand growth** which is strongly dependant on climate policy.
- Possible solutions to reduce barriers for investment **include a range of long-term contracting mechanisms**.
- Neighbouring countries have or are implementing **Capacity Remuneration Mechanisms (“CRM”)**[1], providing incentives for new investment in these countries.
- The presence of **CRMs in neighbouring countries likely further worsens the adequacy outlook** in the Netherlands. Most utilities are actively investing across Europe, and with a CRM in place, neighbouring countries offer a more attractive investment environment than the Netherlands.[2]

Non-exhaustive list of risk factors complicating and an energy-only market to deliver the needed investments in the Netherlands

Complicating risk factors for investments	Impact on investment decisions
I Increasingly volatile wholesale prices and possible price intervention	Increases risk and/or cost for generation leading to a reduction in new entry and an increase in exiting of existing supply
II Increasing gas withdrawal and potential introduction of electricity injection tariffs	
III Uncertain decarbonisation requirements	
IV Uncertain nuclear phase-in and other low-carbon technology procurement policies	
V Uncertainty around the degree of the anticipated demand growth	
VI Capacity markets in neighbouring countries	Higher investment appeal in neighbouring countries

Neighbouring countries have all implemented CRMs



Note: (1) See Appendix 1 for detailed country case studies; (2) A counteracting effect is that more investment in capacity in the neighbouring countries might contribute to the adequacy situation in the Netherlands, but moments of high system stress are highly correlated with neighbouring countries (other than with GB); (3) See German coalition agreement (link).

Our modelling completes the findings from TenneT: the Netherlands is facing significant issues with resource adequacy in the early 2030s

Model assumptions and results

- We calibrate our power system model using the same assumptions as in TenneT's MLZ25 study. In MLZ25 two types of sensitivities were modelled: a lower growth in demand and a stronger decrease of thermal capacity.
- Considering most recent developments, we **add 3 assumption deviations** compared to TenneT's base case assumptions in MLZ25:
  1. A reduction of the expected extension of the **natural gas-fired generator fleet in Germany** in 2033 and 2035 from 57.5 GW to 52.5 GW.
  2. Removal of the assumed **deployed long-duration energy storage ("LDES")** capacity in the NL in all years (0.3 GW in 2030, 1.5 GW in 2033 and 2.4 GW in 2035).
  3. A delay of the **commissioning of LionLink** (1.8 GW interconnector with GB) from 2030 to 2033.
- The three deviations **increase the LOLE** for the 3 target years:
  - In 2030, the higher LOLE is still below the 4h LOLE criteria.
  - In 2033 and 2035, the LOLE is almost doubled compared to the calibration runs and is also higher than MLZ25.

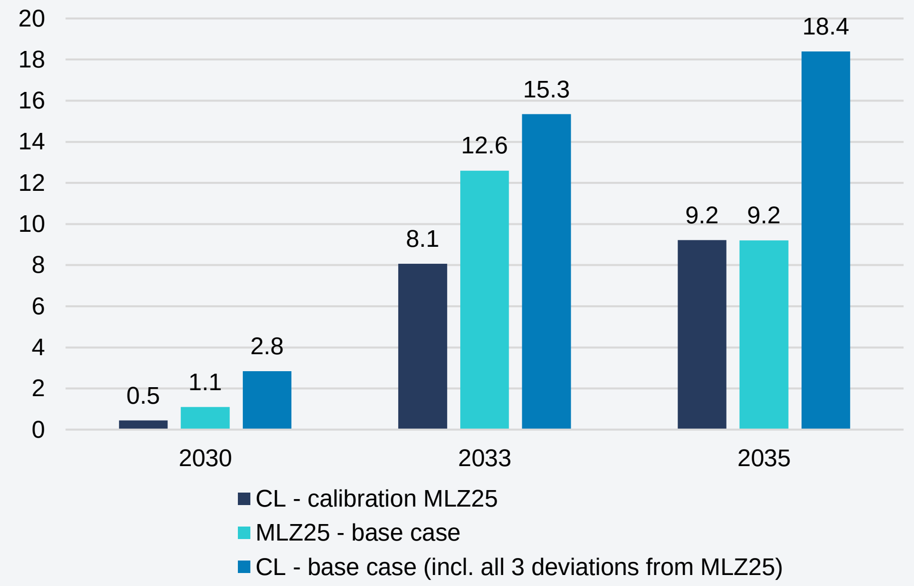
Our analysis indicates that the **adequacy situation** in NL can be further **aggravated** by several **factors that are mostly out of control of Dutch policy-makers**:

- The speed of deployment of gas-fired generation in Germany
- The technological readiness of LDES
- The commission of a new interconnector with GB

Affected years by deviations in CL base case relative to MLZ25

	German gas capacity	NL LDES	LionLink
2030		X	X
2033	X	X	
2035	X	X	

NL LOLE (h) – CL base case includes the 3 assumption deviations[1]



Note: *CL LOLE results assume an "average" outage pattern. In slide 34 we show the results of the impact of each of the deviations individually. For 2030, the LOLE for deviation 2 and 3 individually is 2.6h, i.e. nearly as high as both deviations combined. For 2033 and 2035, the LOLE for deviation 1 and 2 individually is about 50-60% of the LOLE impact of both deviations together. Hence, there is no deviation impacting LOLE significantly more than the other deviations.*

Closing the adequacy gap by storage and demand-side response alone seems challenging, in practice a mix of technologies would be required

Model assumptions and results

- Starting from our base scenario including the three assumed deviations from the TenneT base case, we find that about 2.5-3 GW of additional derated capacity is needed in 2033 and 2035, respectively, to reduce LOLE under the 4h threshold.
- We simulate how much additional capacity of different technologies is required to be installed to close the adequacy gap:

Given the high availability of **dispatchable thermal capacity (here modelled as combined-cycle gas turbines (“CCGTs”))**, an additional capacity of 2.6-3 GW which would imply a small increase of c. 20% in capacity relative to the capacity assumed our base scenario

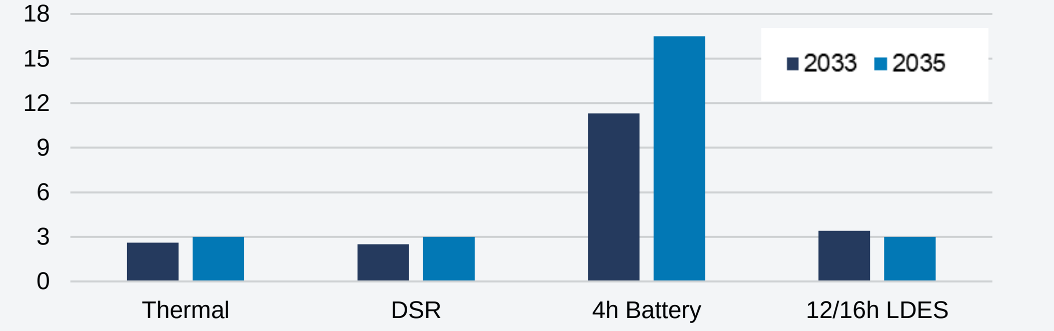
As we model **Demand-Side Response (“DSR”)** to be permanently available and without limitations on the number of activations a very similar additional absolute quantity of DSR is required to reach the 4h LOLE threshold. However, in relative terms this implies more than doubling DSR compared to the base case which seems unrealistic.

A very large increase in **4h-battery capacity** would be required to resolve the adequacy gap. While batteries are valuable for the system (e.g. in terms of providing flexibility), relying on batteries alone to resolve the adequacy issue seems not cost-effective nor realistic.

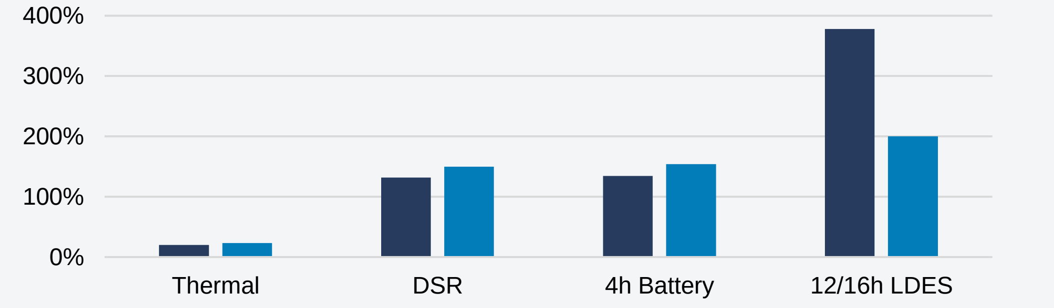
The required capacity of **LDES** to close the adequacy gap is only slightly higher than CCGTs or DSR in absolute terms but would require a significant increase in the already optimistic LDES capacity projects in MLZ25.

Our simulations show that **very high volumes** of storage, DSR and LDES would be required to most close the adequacy gap. The most cost-effective solution would **entail a mix of technologies** with an important role for thermal.

Additional capacity needed to meet the 4h LOLE standard[1,2] (GW)



Increase in capacity relative to our base case scenario[1,2] (%)



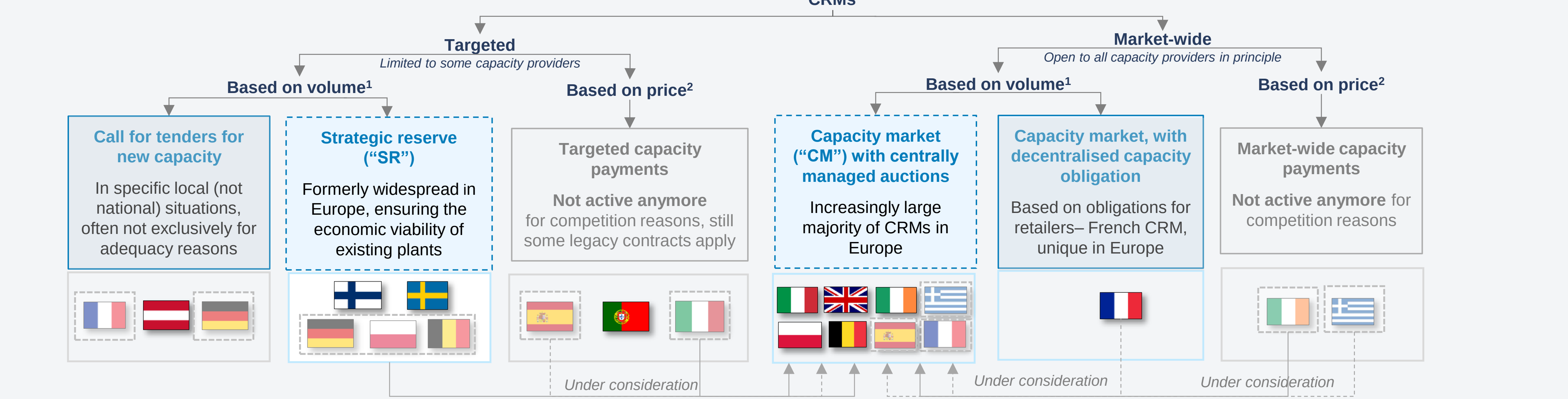
Note: *(1) We use combined-cycle gas turbines (“CCGT”) as the thermal technology in our modelling, similar results can be expected for other dispatchable thermal technologies like coal plants being converted to biomass. (2) As we do not consider any LDES in our scenario, we use the TenneT’s 12/16h LDES capacities as the base value for incremental 12/16h LDES required to reach the 4h-LOLE threshold. We assume 12h batteries in 2033 and 16h batteries in 2035. LDES capacities in MLZ’s dashboard and the report differ, and we rely on the report figures.*

In the EU there is a trend towards centralised capacity markets to address evolving adequacy concerns and deliver needed investments

Experiences and potential solutions

- Different solutions have been introduced in the EU over the last two decades:
  - **Capacity payments** are being phased out due to their administrative nature.
  - **Strategic reserves ("SR")** were introduced in many countries but have been gradually replaced by **centralised market-wide capacity mechanisms, referred to as capacity markets ("CM"),** as the needs in those countries evolved from keeping existing capacity online to incentivising investment in new capacity.
- Considering the adequacy concerns and these trends in the EU, both the KGG and the ACM describe the need to **analyse the merits of an SR and a CM**.
- The KGG also describes other potential solutions such as **targeted procurement of DSR or LDES**. While these technologies are valuable for the system (e.g. for flexibility), our analysis shows that only relying on them to close the adequacy gap will likely not be realistic (see previous slide).

Taxonomy and evolution of CRMs in the EU



Note: *(1) Fixed volume and market-determined capacity remuneration price; (2) Capacity remuneration price fixed administratively.*

We combined a qualitative and qualitative assessment to analyse the two most common solutions: a strategic reserve and a capacity market

Combined methodology to assess the merits of an SR vs CM

- **Qualitatively**

  Not all impacts of CM or SR implementation can be modelled. Hence a comparative analysis is required to **complement the quantitative assessment. Relevant assessment criteria are:**

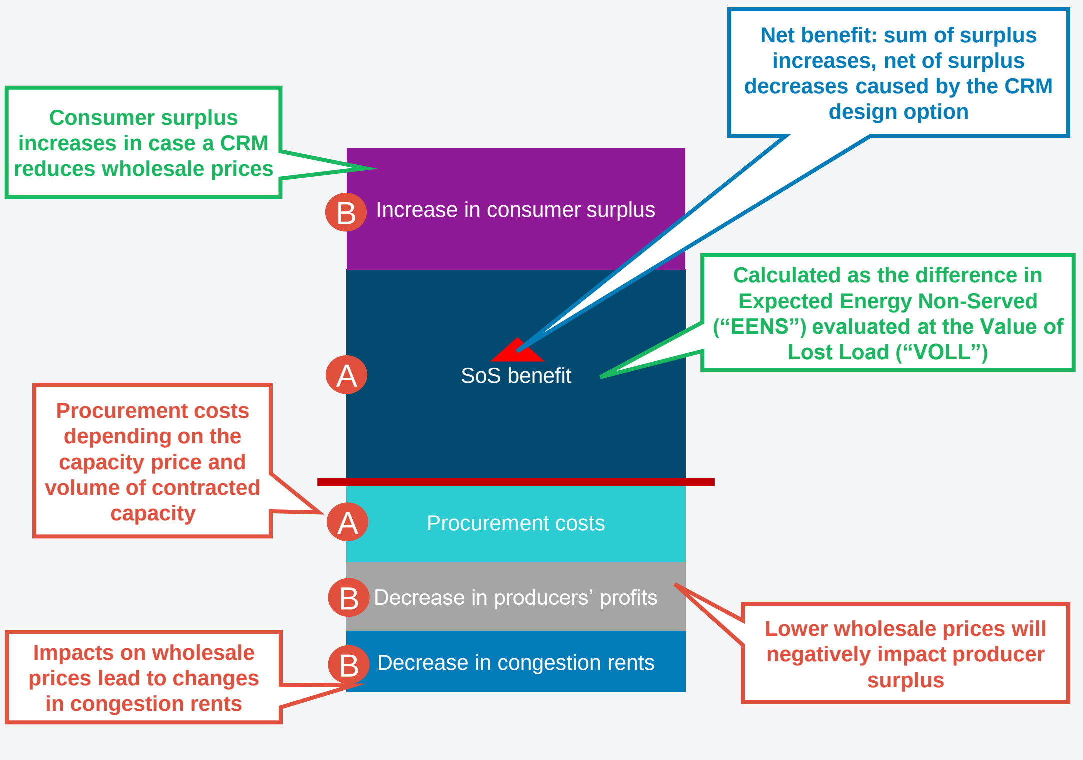
  - i. Speed of implementation; ii. Well-tested; iii. Investment derisking; iv. Level-playing field across countries; v. Technology neutrality and vi. Robustness.

- **Quantitatively**

  The procurement costs of SR are typically lower than a CM but to compare the merits of each solution more holistically their **net welfare benefits need to be quantified:**

  - The welfare benefit of an SR is the **Security of Supply ("SoS") benefit**. The SoS benefit is quantified by the reduction in Expected Energy Not Served ("EENS") due to the introduction of the mechanism multiplied by the Value of Lost Load ("VOLL").
  - A CM will, in addition to creating a SoS benefit, also impact **wholesale ("WS") market prices** due to the introduction of additional capacity in the market (relative to an energy-only market). WS price impacts lead to changes in consumer surplus, producer surplus and congestion rents, which need to be accounted for to be able to **compare the welfare benefits of an SR and a CM on a like-for-like basis**.

Methodology to quantify the net welfare benefits of SR/CM



A: relevant for the welfare assessment of both mechanisms

B: only relevant for the welfare assessment of a CM

A CM enables the required investments, which is the fundamental problem in the Netherlands - an SR does not and hence is not a structural solution

Qualitative comparison of both mechanisms

- An SR and a CM are **different in nature and purpose**:
  - **An SR** has typically been introduced as a **temporary insurance** to avoid brown-outs by reserving thermal capacity. Only existing capacity can be part of an SR. Policymakers continue to **rely on the energy-only market to attract investments in new capacity**.
  - In contrast, **a CM**'s aim is to find the **optimal balance between retaining existing capacity and attracting investments** across all types of technologies. Under a CM, a share of market participants' WS market revenues, in particular from unpredictable scarcity prices, is exchanged for more stable revenues from competitively-determined capacity payments.
- We assessed the pros and cons of an SR and a market-wide CM to close the adequacy gap. Both mechanisms have been well-tested, in addition:

Dynamic efficiency
  - Only a **CM reduces investment risk**, which is the fundamental problem in NL**,** by providing a steady revenue stream and lowering volatility of wholesale prices leading to a reduction of hurdle rates.
  - A CM would **level the playing field** between investment in NL and its neighbours and potentially open the door to a regional approach.
  - A **technology neutral** CM leads to investment in the most cost-effective mix; this is important in Dutch context as likely various technologies will be required to close the adequacy gap.
  - A CM is **robust** as low or high stress adequacy situations in NL will be reflected in the capacity prices, rather than potentially necessitating the need for a patchwork of different mechanisms complementing an SR to cater a changing environment, each taking long processes to design.

Group	Criterion	Strategic reserve	Centralised market-wide capacity mechanism
	A Speed of implementation	Can be relatively quick	Longer implementation but acceleration possible
	B Well tested	Has been in many countries	In place in many countries
Dynamic efficiency	C De-risk investment	Only for capacity in SR, not addressing new investment	For existing and new capacity[1]
Dynamic efficiency	D Level-playing field across countries	Unaddressed, except for participating capacity	In place or planned in neighbouring countries
Dynamic efficiency	E Technology neutral	Focused on existing thermal, sometimes includes DSR	Increasingly varying procurement mix
Dynamic efficiency	F Robust	Can lead to a patchwork of mechanisms	Can provide a fit-for-all solution
Quantified	G Limit procurement cost	Lower due to limited to capacity participating SR	Higher but varies per design and eligibility
Quantified	(Input) H Positive welfare impact	Positive but lower than most efficient CM variants	Positive and higher than SR for most efficient CM variants

See next slide for quantification results

Note: (1) A CM as well reduces risk premia for retailers and overall collateral requirements due to lower WS price volatility under a CM relative to under an SR.

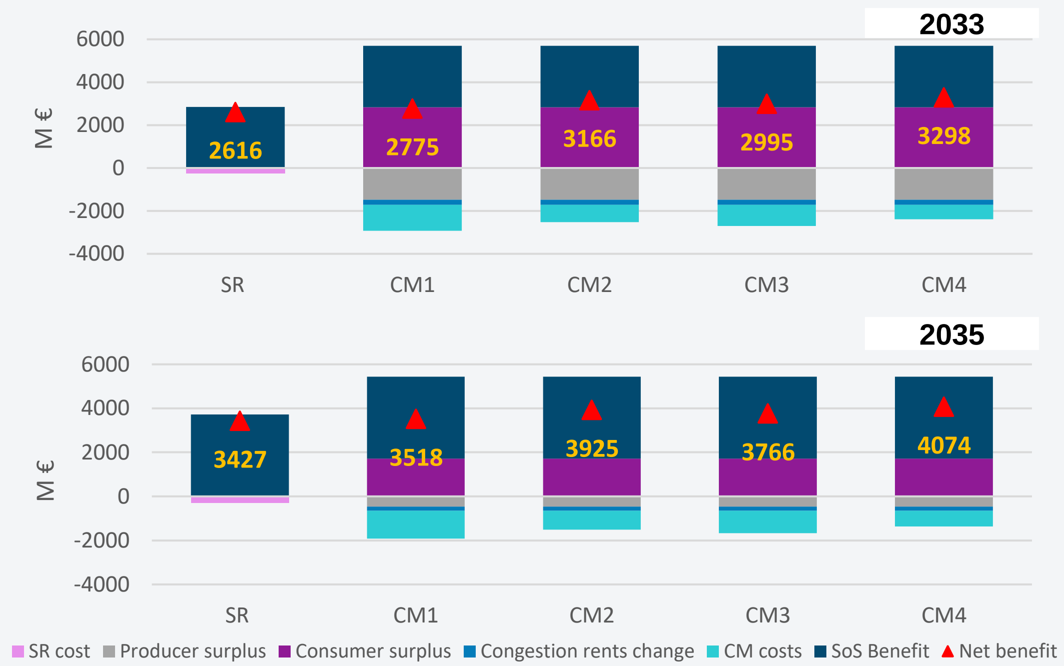
Implementing an SR or CM would enhance welfare over the status quo, with benefits in the same range but potentially higher with a CM

In the report we simulate various technologies

Quantitative assessment of welfare under SR and CM scenarios shows:

- A **positive net benefit both in the SR and CM scenarios**, mainly driven by the large SoS benefits due to a VOLL at 69k€/MWh. The net benefit ranges between 2.5 and 3 B€ per year in 2033 and 3-3.9 B€ per year in 2035.
- While the **procurement costs of a CM are higher than those of an SR**, **the net benefit of an SR falls within the range of benefits of different CM scenarios**:
  - The additional capacity procured via a CM (relative to an energy-only market or an SR) is active in the WS market, leading to a reduction in the WS price which, in its turn, leads to consumer surplus gains superseding impacts on producer surplus and congestion rents. Overall, a positive net WS benefit results.
  - Total net welfare benefits vary across CM scenarios, eligibility and capacity price differentiation. Under a **scenario new CCGT are procured in the CM** - as shown on the right - **all CM variants have higher welfare benefits** than an SR.
- An important finding in the Dutch context is that **more thermal capacity is required to be procured in an SR vs a CM.**[2] This can be explained by:
  - Thermal capacity procured via a CM is active in the WS market helping to charge up batteries when the system is tight or avoid them to then discharge. In contrast, thermal plants in an SR are not active in the market to support the charging of batteries in hours leading up to scarcity events. Reserved thermal units are only activated in the event of scarcity during which many batteries might be depleted as they had to discharge in earlier close-to-scarcity hours.
  - There are limited loss-of-load events in neighbouring countries, which would have the effect to inflate the capacity procured in the Dutch CM.
- We also find **wholesale price volatility to reduce under a CM relative to an SR**, i.e. a reduction of 10-15% in the standard deviation of hourly wholesale prices, which reduces costs related to collateral and the likelihood of costly bankruptcies.

Quantified welfare impacts SR and CM implementations - new CCGT scenario[1]

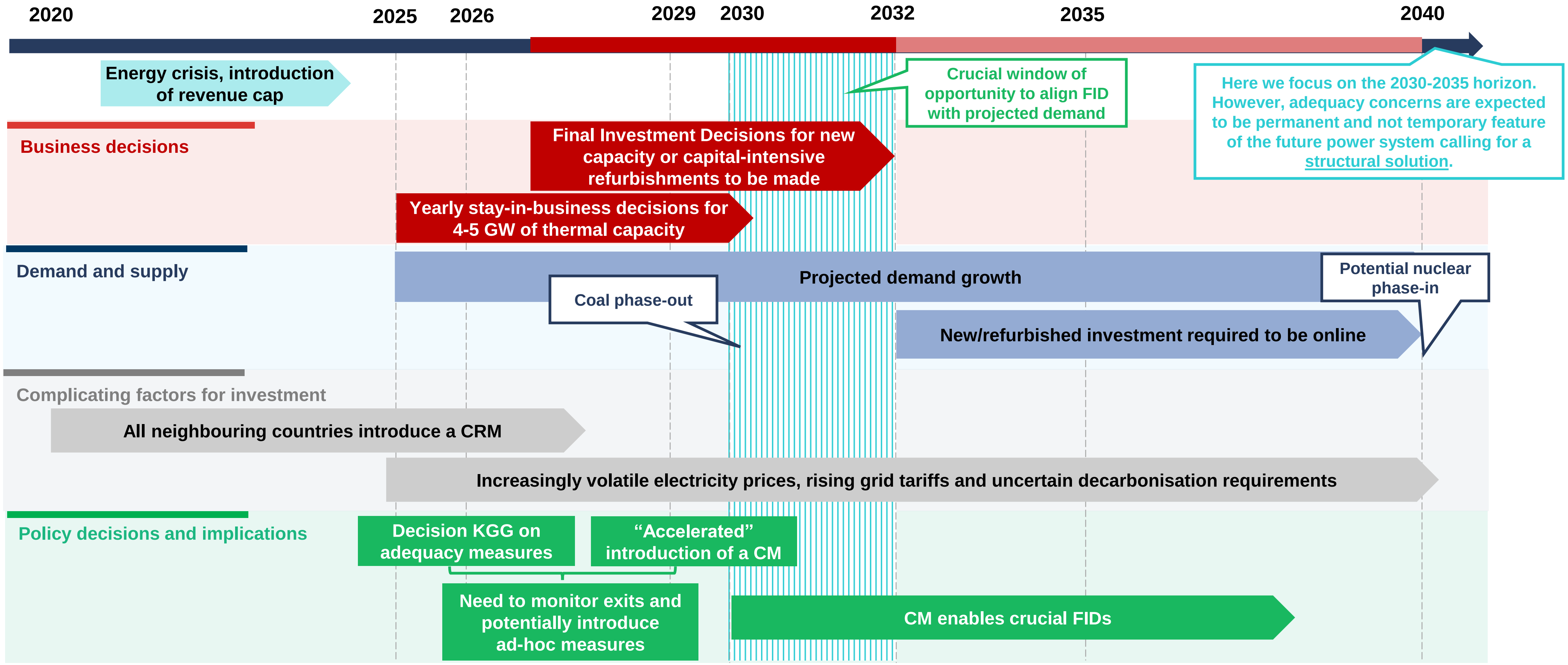


	Eligibility	Price
CM1	All	Unique price
CM2	All	Separate prices
CM3	Excl. RES	Unique price
CM4	Excl. RES	Separate prices

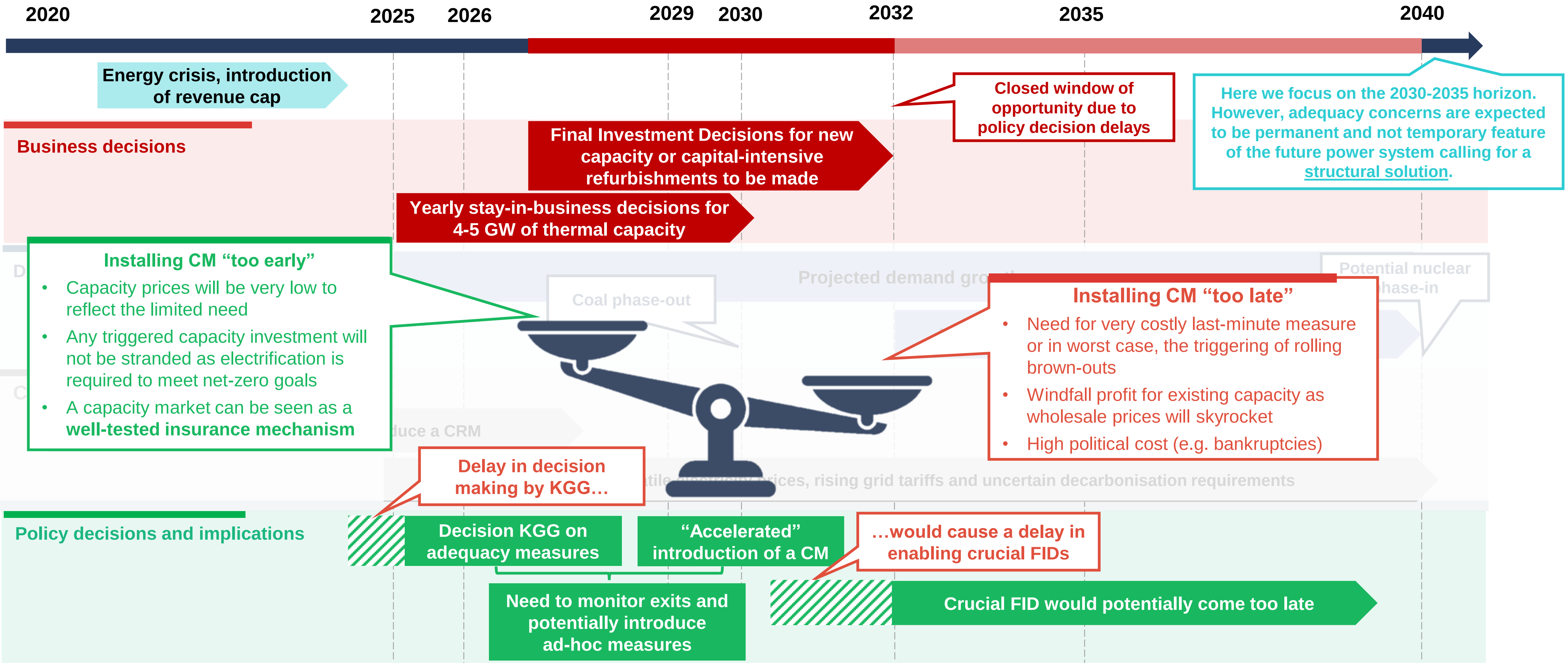
Note: *In line with our Economic Viability Assessment ("EVA"), we assume a unique CM clearing price of €50k/MW and CM clearing prices of €50k/MW and €30k/MW for new and existing capacity, respectively. Raising the unique/new CM clearing price to €85k/MW leads to lower welfare benefits of CM1/3 than an SR but welfare benefits of CM2/4 remain higher.*

Notes: *(1) In 2030 the LOLE threshold is not exceeded, hence no additional capacity is modelled; (2) This finding is not the main driver of the quantitative comparison, i.e. the reduction in the SR procurement costs would be below 200m€/y if the same volume of thermal capacity would be procured under the SR and the CM (leading to not reaching the 4h-LOLE threshold for the SR).*

Considering the strong risk of adequacy concerns and welfare benefits of an intervention, we recommend the introduction of a CM…



… without delay as the costs for being too early are much lower than being too late



2.

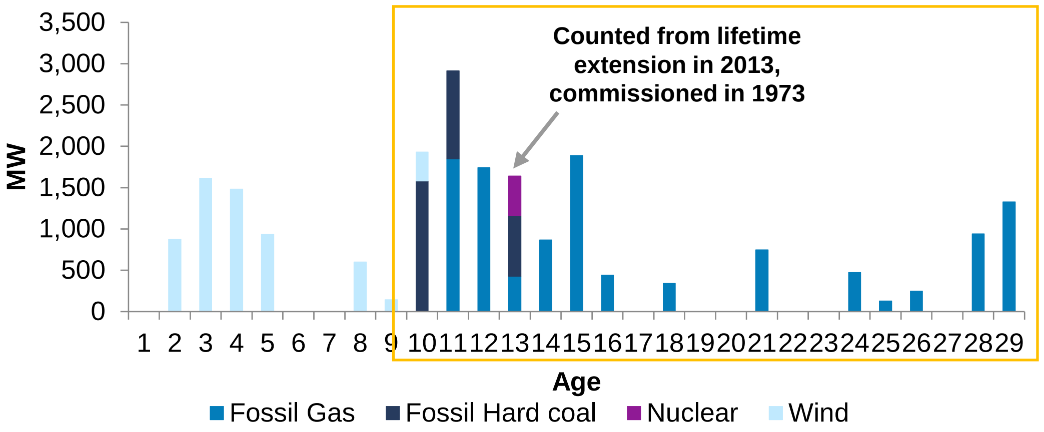
Adequacy outlook in the Netherlands

2.1

Key trends in the Dutch power system

On the supply side, the thermal fleet is aging, c. 4 GW of coal plants will exit by the end of 2029 and there are additional external supply risks

Capacity by age and technology in the Netherlands as of 2025



- In December 2019, NL adopted a law **prohibiting the use of coal for electricity generation as of 2030 at the latest**. Some power plants were already required to shut down by 2020 or latest 2025 in case of low efficiency levels. Some of the coal plants might be converted to biomass plants but this would require significant investment.
- In addition, the already **advanced age of many gas power plants** will require investments for refurbishment to keep the plants running. Every year, 4-5 GW of thermal plants make stay-in-business decisions with multi-year payback periods. The last FID of a merchant dispatchable plant was in 2010.
- The Borssele plant is the only nuclear power plant in the Netherlands, **commissioned in 1973**. In 2013, the **lifetime was extended** until 2033.

Other risks to NL security of supply stem from **external developments**:

- The Economic Viability Assessment ("EVA") from the ERAA process results in almost 24 GW **additional gas capacity in Germany**. Although an increase in gas capacity in Germany is expected following government announcements, it is **uncertain when these will be added**.
- MLZ25 further assumes 1.8 GW **additional interconnector ("IC") capacity** between NL and Great Britain ("GB") from the Hybrid LionLink IC by 2030. Yet, **commissioning is expected to only take place earliest in 2032**.
- Moreover, MLZ25 assumes c. 27 GWh of multiday **LDES** by 2030 and up to c. 51 GWh of intraday and multiday LDES by 2035. Still, the deployment of LDES capacity remains subject to **technological readiness, particularly for multiday LDES.**

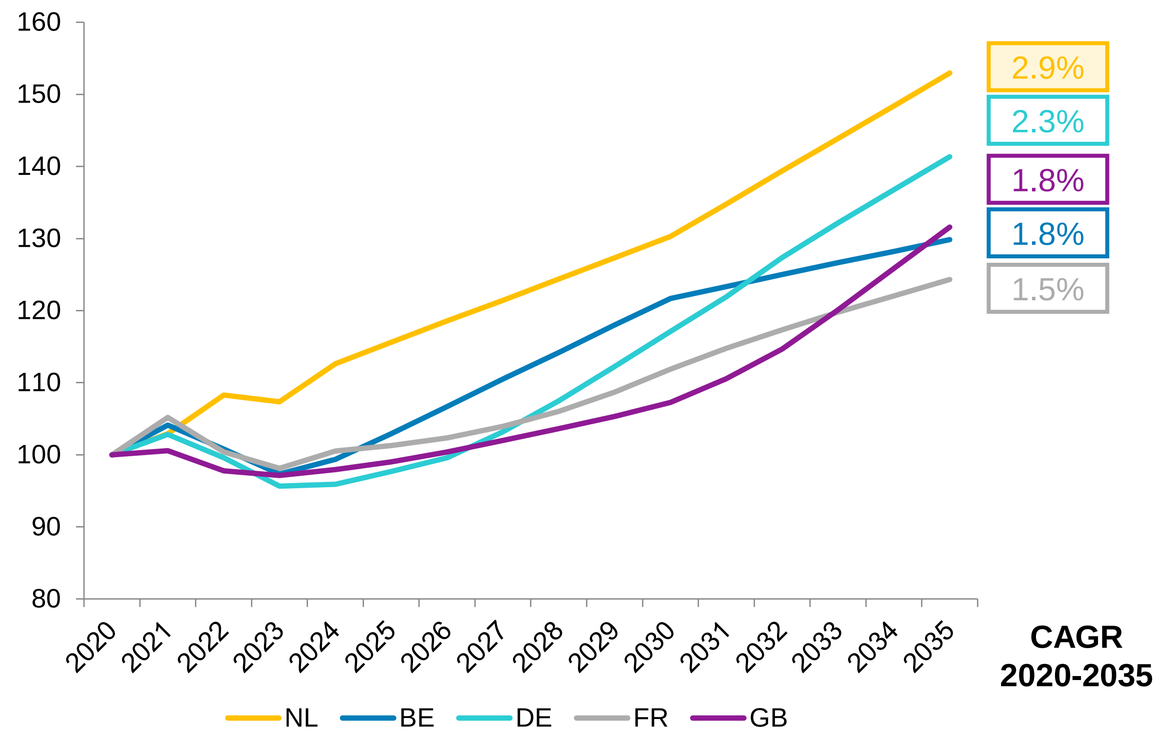
Assumptions for LDES in TenneT's MLZ25[1]

LDES type	Volume (GWh)			C-rate (all years)	Efficiency (all years)
Intraday LDES	-	10.8	24	C/12 (2033) C/16 (2035)	70%
Multiday LDES	26.9	26.9	26.9	C/84	99%

__Source:__ ENTSO-E Transparency Platform (link); Staatsblad van het Koninkrijk der Nederlanden, 19 December 2019 (link); Dutch Ministry of Climate and Green Growth 2025, Letter to Parliament, 11 February 2025 (link); TenneT, Monitor Leveringszekerheid 2025, 15 May 2025 (link); Dutch Federal government, Nuclear Energy (link).
__Note:__ (1) In the MLZ25, multiday LDES is modelled as compressed air energy storage which has a round-trip efficiency of >100% because the air coming back out of the system 'takes' natural gas with it. This could not (yet) be represented in the modelling, so the efficiency was set to 99%.

The demand growth forecasted in the Netherlands is stronger than in its neighbouring countries due to faster anticipated electrification

Evolution of electricity demand in the Netherlands and neighbouring countries, base year index (2020 = 100)

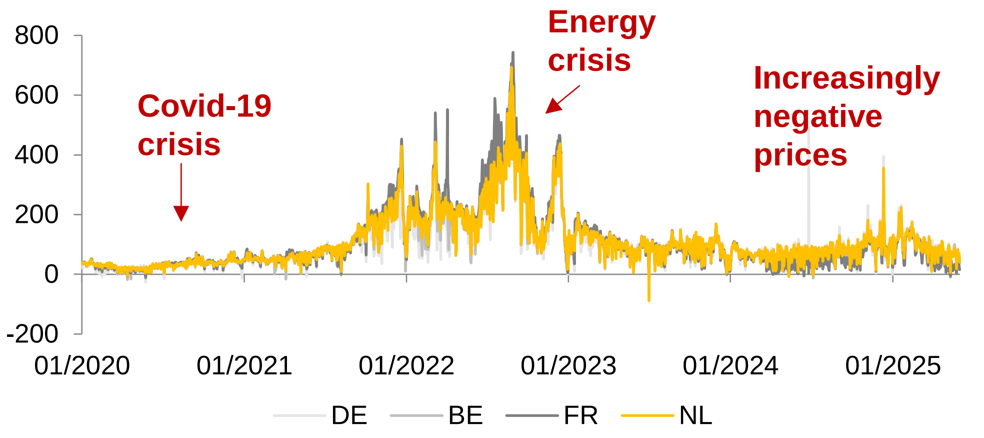


- The **Netherlands** exhibits the **strongest anticipated growth in electricity demand** to 2035 compared to 2020 levels, among neighbouring countries.
- This can be explained by:
  - **Electrification of transport**: in 2024, NL was the fourth largest market for **battery electric vehicles** ("BEVs") in Europe, with **35% of car sales being BEVs**. As of 2024, **14%** of the passenger car fleet were **hybrid or BEVs**. The country also concentrates almost 30% of EV charges in the EU.
  - **Low acceptance of gas**, in particular gas extraction in the province of Groningen: while gas is **still a dominant source for heating**, its **share is decreasing** (from 87% of space heating in 2015 to 73% in 2023) and the government's plan is to increasingly **switch to heat pumps, and to become gas-free by 2050**.

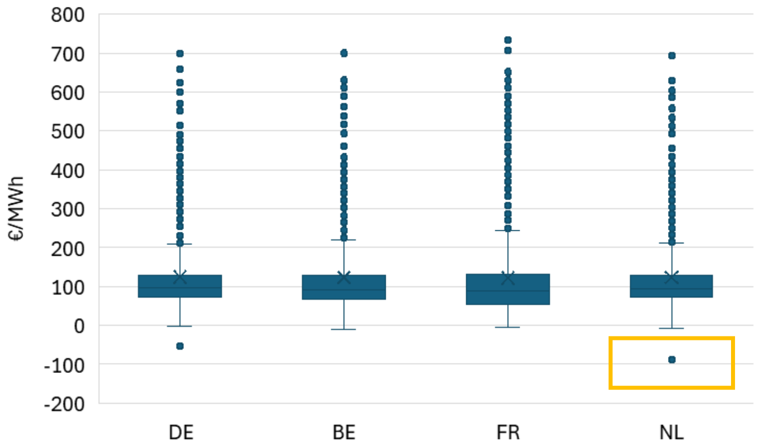
Source: *ENTSO-E, ERAA 2024, (link); The Electric Car Scheme, The countries with the best EV uptake, 19 January 2025 (link); ACEA, Electric cars, 22 June 2022 (link); Eurostat, Hybrid & electric cars make up 48% of new registrations, 13 December 2024 (link); RUG, Gas extraction, 16 September 2020 (link); Gasunie, Heat grids (link); Netherlands Court of Audit, A cold shower for heat networks, 4 February 2025 (link); Eurostat, Energy consumption in households, June 2025 (link).*

Volatile prices, including frequent negative prices, increase risk for investment in existing and new dispatchable capacity

Wholesale prices in the Netherlands and neighbouring countries, 2020-2025



Volatility of wholesale prices in Netherlands and neighbouring countries, June 2022-May 2025



- **Large price volatility**, and especially periods of **negative prices**, have been observed in the past years in the Netherlands. While other countries exhibit similar trends, **negative price occurrences are particularly important in the Netherlands**. Considering data over the past 3 years, average daily wholesale prices have been as low as **-90€/MWh in the Netherlands**, compared to a minimum of -5 to -10 €/MWh in France and Belgium, and -50€/MWh in Germany. In 2024, there were between **5% and 8% of negative price hours**.
- **The share of intermittent renewables in NL is particularly high** compared to other countries (increased from 26% in 2020 to 46% in 2023 compared to 31% in Belgium and 30% in France).The **SDE++ support scheme** compensates for the difference between market prices and a pre-determined price, attracting large amount of renewables and giving **sustained incentive to produce**, even when prices become negative.
- Liquidity in forward markets dries up 2-3 years in the future, scarcity prices occur but are hard to anticipate and a **revenue cap** has been introduced according to EU guidelines during the **energy crisis**. Hence, the upside of price volatility is heavily discounted when taking investment decisions regarding existing and new capacity.

Source: ENTSO-E Transparency Platform (link); Eurostat, SHARES (link); Energy News, The rise of renewable energy increases negative price episodes in Europe, 10 April 2025 (link).

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The introduction of electricity injection tariffs and increases in gas network tariffs weaken investment incentives compared to neighbouring countries

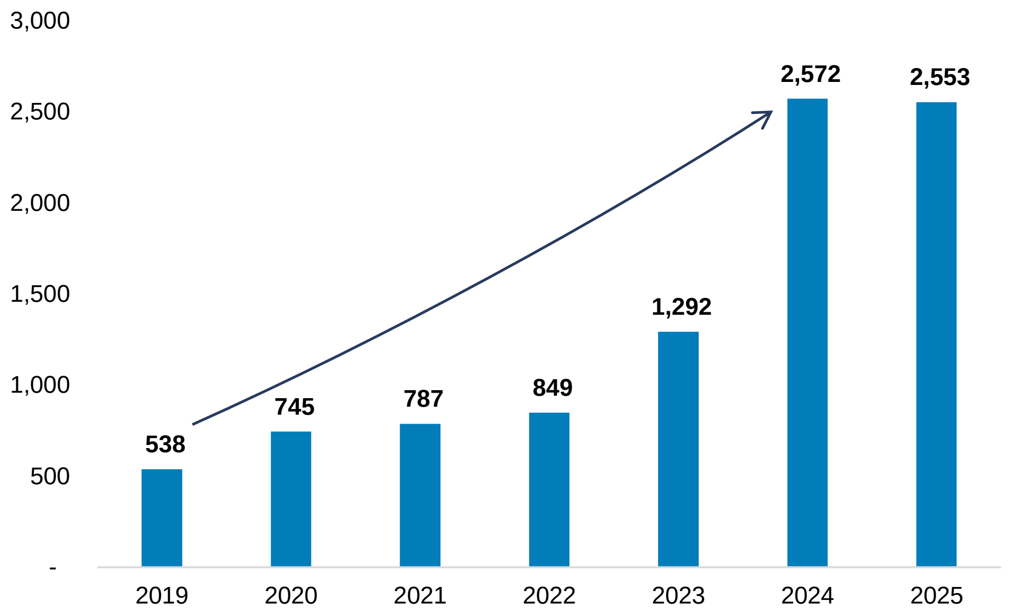
Electricity injection network tariffs

- In October 2024, ACM announced that they are **starting preparations for the introduction of injection tariffs.** The ACM aims to publish a draft decision for injection tariffs in 2026. The exact design of these tariffs which would fall on generators is not yet known.
- The step follows **significant increases in expected grid costs** in the coming years required for grid expansion and reinforcement. Between 2023 and 2024, the allowed revenue of TenneT has already increased by c. EUR 1.3 billion.
- In light of rising grid costs, ACM aims to make changes to the **distribution** of costs among grid users. So far, only consumers bear grid costs.

Gas network tariffs

- On average, the proposed **gas transport network tariffs for 2026 would increase by 48% relative to 2025,** while in 2025 the tariffs already increased by 52% compared to 2024. In 2024, tariffs had dropped by 20% due to much higher income from the sale of interruptible capacity.
- The tariff increase in 2025 is mainly caused by higher revenues as a result of the changed method decision 2022-2026 and by a decrease in the expected gas transmission capacity to be sold.

TenneT's allowed revenue (in M€)



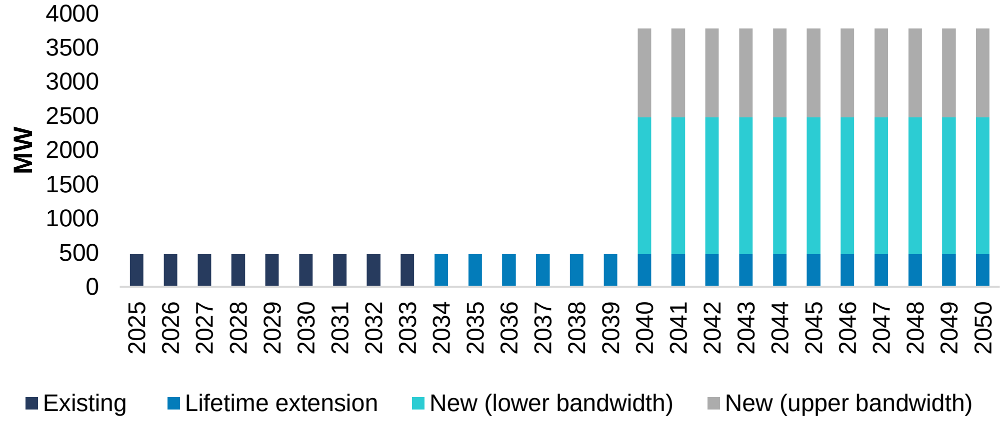
Even if generators could pass-through the increased network costs, impacts on revenues occur via:

- Cross-border competition
- Cross-technology competition

***Source**: ACM 2023 (link); ACM 2024 (link); ACM 2025 (link); ACM Decisions 2019 (link), 2020 (link), 2021 (link), 2022 (link), 2023 (link), 2024 (link), 2025 (link); CE Delft (link); Gasunie, Tariffs decision 2025, 24 May 2024 (link).*

There is high policy uncertainty among which around new nuclear, decarbonisation requirements for thermal and targeted flexibility schemes

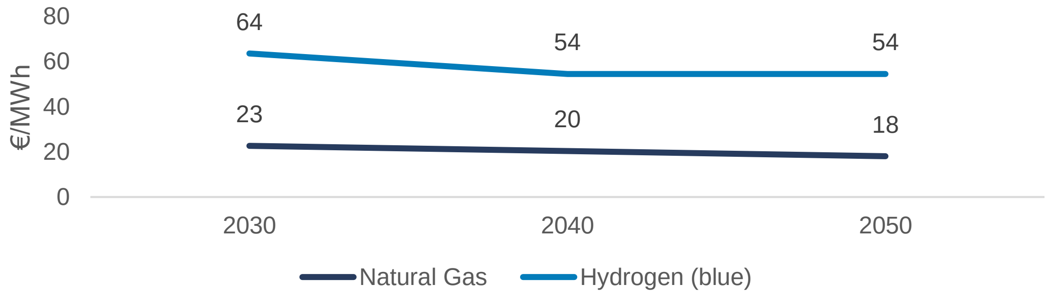
Existing and initially planned nuclear capacity by 2040



- The Netherlands aim to add up to **3.3 GW of new nuclear capacities by 2040**. However, it remains uncertain if the target can be achieved in time.
- Due to **delays** in the site selection process, the Dutch government stated in February 2025 that it does **no longer seem realistic to have the first new nuclear power plant operational in 2035**, as initially planned.
  - The statement follows delays in the site selection process.
  - The government added that at this point the timeline for the tendering, licencing and ultimately the final construction remains uncertain.
- In line with these issues, TenneT does not assume any additional nuclear capacity to be connected by 2035 in their security of supply monitoring.

- The power system is targeted to be net zero by 2035 but **requirements around blending** are highly unclear.
- In case strong blending or other decarbonisation requirements would be enforced on thermal capacity, the **availability of "clean fuels" and its costs,** e.g., green hydrogen, remains unclear.
- Overall uncertainty around decarbonisation requirements, which can significantly raise the cost of electricity production from thermal units, stifle stay-in-business and new investment decisions.
- At the same time thermal plants might face increasing competition from storage and demand-side response ("DSR") potentially supported via the introduction of **targeted flexibility procurement schemes**.

Price projections for natural gas and blue hydrogen in TYNDP 2024

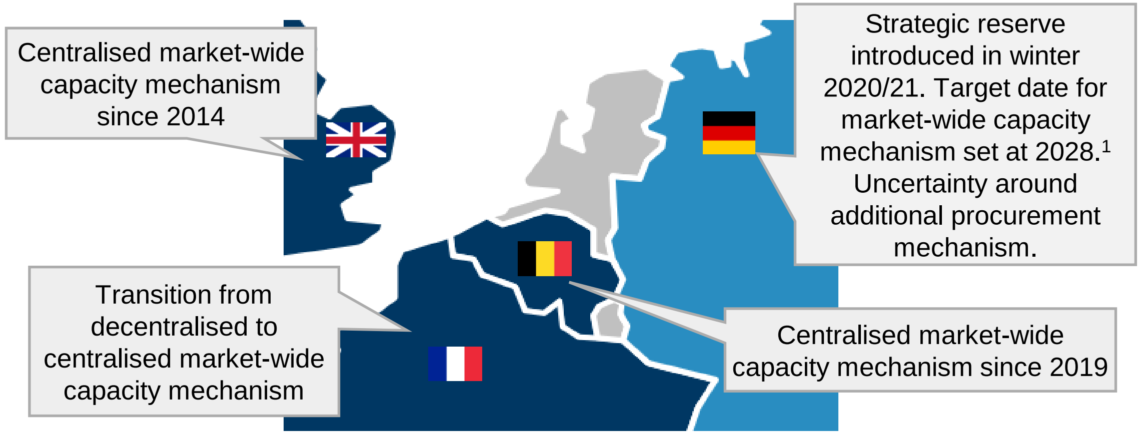


__Source:__ ENTSO-E Transparency Platform (link); Staatsblad van het Koninkrijk der Nederlanden, 19 December 2019 (link); Dutch Ministry of Climate and Green Growth 2025, Letter to Parliament, 11 February 2025 (link); TenneT, Monitor Leveringszekerheid 2025, 15 May 2025 (link); Dutch Federal government, Nuclear Energy (link); TNO, Evaluation of the levelised cost of hydrogen based on proposed electrolyser projects in the Netherlands, 13 May 2024 (link).

Similar challenges have led to neighbouring countries introducing a CRM – which in turn impacts the attractiveness of investing in the Netherlands

- While every context has its own particularities, similar challenges as listed below have led to project developers/investors in the electricity sector across Europe increasingly becoming reliant on long-term contracting mechanisms, both to cover missing money and to de-risk investments.
- Recognising these challenges, all neighbouring countries implemented a CRM, providing improved incentives for new investment.
  - On the one hand, more investment in capacity in the neighbouring countries might contribute to the adequacy situation in the Netherlands but moments of high system stress are highly correlated with neighbouring countries (other than with GB).
  - On the other hand, utilities are active across the world and countries with a CRM will be more attractive for international investors/companies.
- Overall, the introduction of **CRMs in neighbouring countries likely further worsens the adequacy outlook in the Netherlands.**

Neighbouring countries have all implemented CRMs



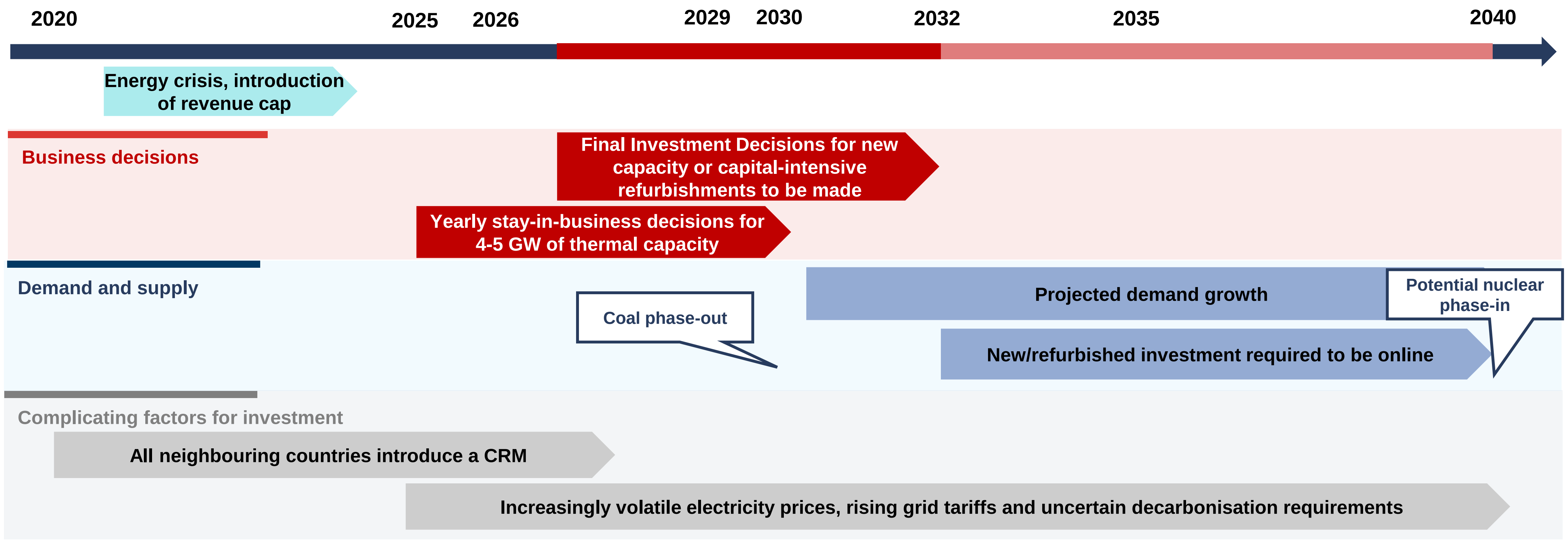
Since the energy crisis, a capacity remuneration mechanisms have been viewed as integral parts of the electricity market design.

Structural drivers impacting the Dutch adequacy and examples of risk factors complicating an energy-only market to deliver the investments

	#	Driver / factor	Impact
Structural drivers	1	Coal exit set in 2030, uncertain outlook for aging thermal fleet	Likely exit of important share of existing thermal capacity
	2	Risky environment for entry of merchant dispatchable capacity	Very unlikely entry of any merchant dispatchable capacity
	3	Uncertainty on DE capacity, GB interconnector, tech. readiness	Additional supply uncertainty that is largely out of control of NL
	4	Expectation of rising demand in NL	Increased need for extending existing capacity and new entry
Complicating factors	I	Incr. wholesale prices volatility	Increases risk and/or cost for generation leading to a reduction in new entry and an increase in exiting of existing supply
	II	Gas withdrawal, elec. Inject. tariffs	
	III	Uncertain decarb. requirements	
	IV	Uncertain nuclear phase-in	
	V	Uncertain demand growth	
	VI	CRMs in neighbour countries	Higher investment appeal outside NL

Note: (1) See German coalition agreement (link).

These risks and uncertainties lead to a “perfect storm” creating significant adequacy concerns in the early 2030’s



Source: *ENTSO-E, ERAA 2024, (link); The Electric Car Scheme, The countries with the best EV uptake, 19 January 2025 (link); ACEA, Electric cars, 22 June 2022 (link); Eurostat, Hybrid & electric cars make up 48% of new registrations, 13 December 2024 (link); RUG, Gas extraction, 16 September 2020 (link); Gasunie, Heat grids (link); Netherlands Court of Audit, A cold shower for heat networks, 4 February 2025 (link); Eurostat, Energy consumption in households, June 2025 (link).*

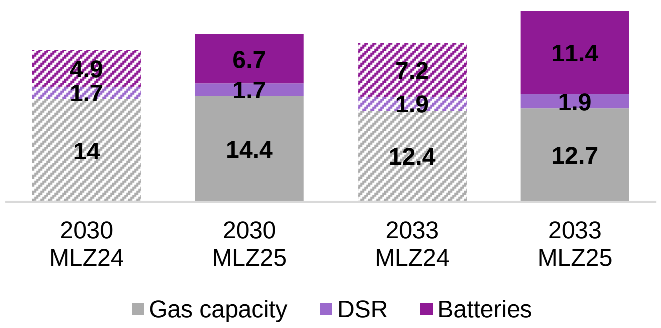
2.2

ERAA & TenneT adequacy assessment

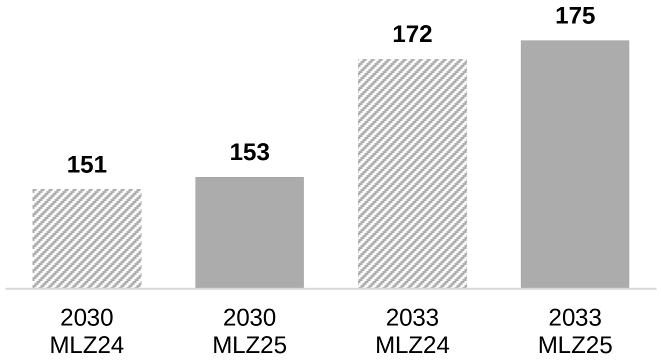
TenneT's study MLZ 2025 confirms the post 2030 adequacy concerns identified in MLZ 2024 with LOLE higher than the 4-hour standard

Assumptions

Gas, DSR and battery capacities (in GW)

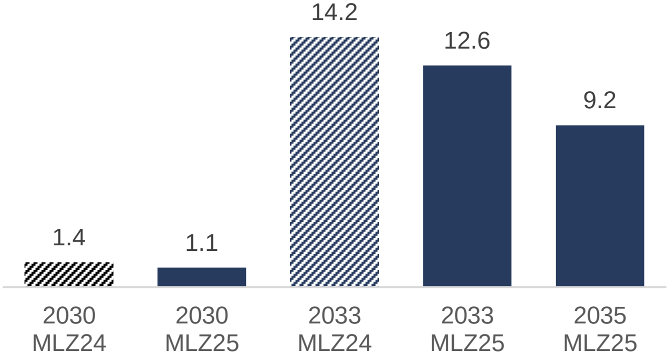


Electricity demand (in TWh)

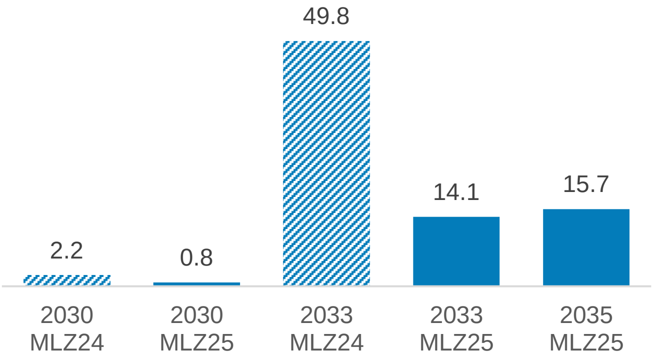


Results

LOLE (in hours per year)



EENS (in GWh per year)



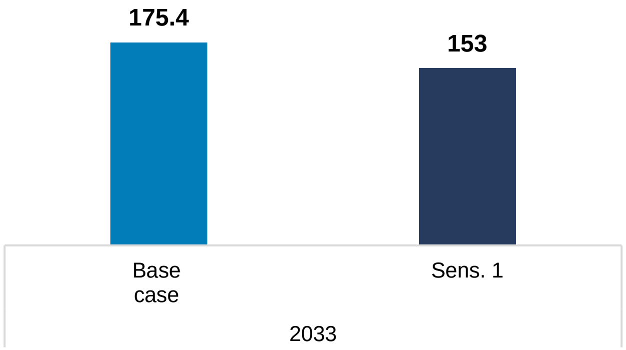
- In MLZ25, despite improvements compared with MLZ24, the **LOLE in 2033 and 2035** are still **higher than the 4-hour requirement**.
- For the **LOLE**, both analyses show higher levels in 2033, with a **slight decrease in MLZ25**. In terms of Expected Energy Not Served (**"EENS")**, the results in MLZ25 suggest a **significant improvement**.
  - For 2033, EENS drops from c. 50 GWh per year in MLZ24 to c. 14 GWh per year in MLZ25.
  - Improvements can be **partially** driven by developments in **storage capacities**.
  - The **new weather scenarios** in MLZ25 could be the key driver for changes in EENS levels.

Source: *Compass Lexecon analysis based on TenneT MLZ25.*

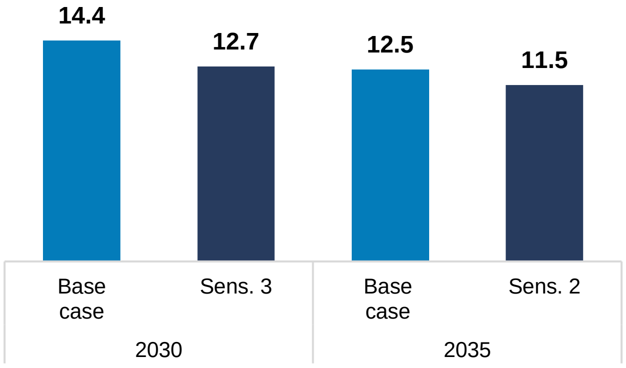
The sensitivity analyses to assess the impact of demand and gas capacity risks in TenneT's MLZ25 suggest adequacy concerns as early as in 2030

Assumptions

Electricity demand (in TWh)

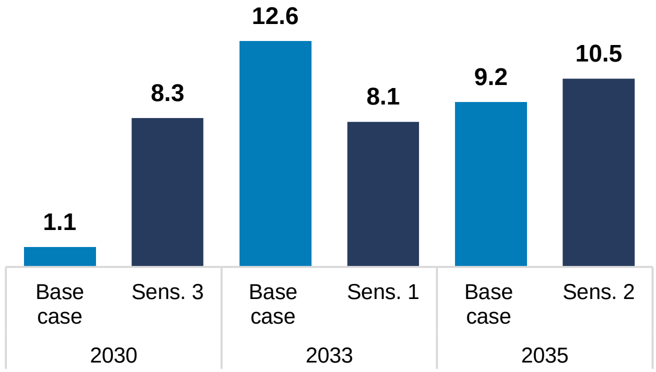


Gas capacity (in GW)

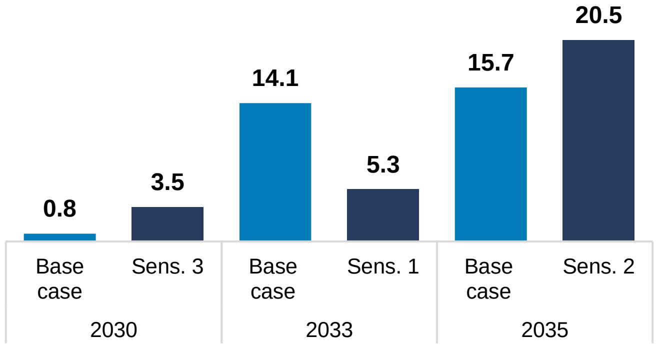


Results

LOLE (in hours per year)



EENS (in GWh per year)



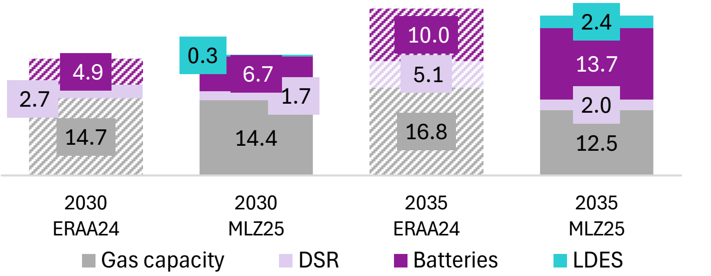
- Sensitivity analysis 1:
  - Assumes **lower electricity demand** (and lower peak demand[1]) in 2033, leading to **lower** LOLE and EENS levels.
  - Though LOLE and EENS decrease, the levels still suggest a **need for increasing system flexibility**.
- Sensitivity analysis 2:
  - Assumes **1 GW less gas capacity** in 2035, leading to **higher** LOLE and EENS levels.
  - Results suggest some additional situations where NL cannot meet electricity demand.
  - The impact may be mitigated by distributing shortages across countries, highlighting the relevance of SoS in neighbouring countries.
- Sensitivity analysis 3:
  - Assumes **1.7 GW less gas capacity** in 2030 to **reflect the Economic Viability Analysis ("EVA") results**, leading to **higher** LOLE and EENS levels.
  - These results suggest potential important loss of generation capacity already as early as 2030.

Note: *(1) With a 13% reduction in electricity demand in Sensitivity analysis 1 and assuming a peak demand of c. 25 GW (see Figure 3-2 in MLZ25), the lower electricity demand would correspond to a reduction in peak demand by c. 3 GW.*
Source: *Compass Lexecon analysis based on Tennet MLZ 2025.*

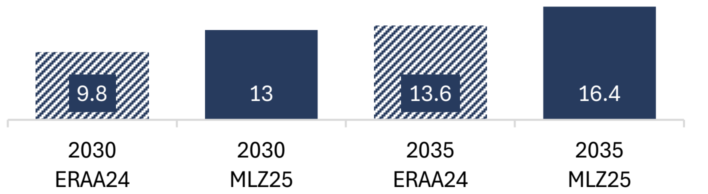
ENTSO-E's study ERAA 2024 model results also show that the 4h LOLE standard could be missed as early as 2030

Assumptions

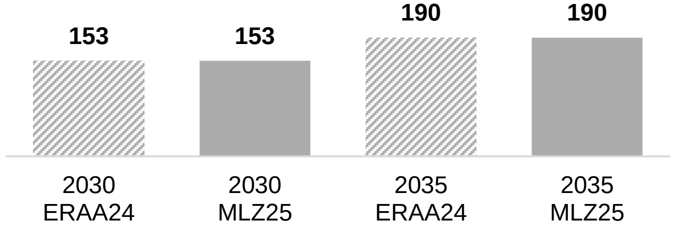
Gas, DSR and battery capacities (in GW)



Interconnector capacity (in GW)

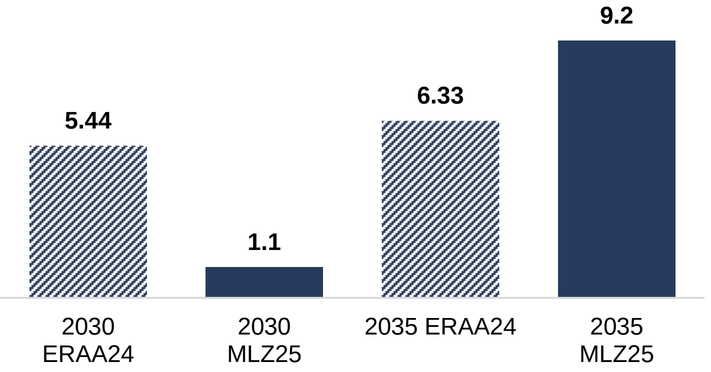


Electricity demand (in TWh)

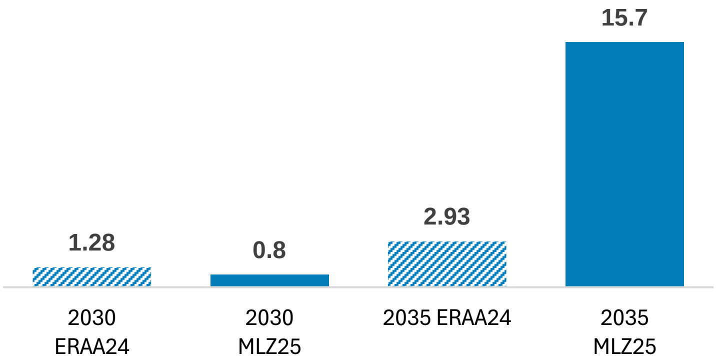


Results

LOLE (in hours per year)



EENS (in GWh per year)



- Compared to MLZ25, **ENTSO-E's study ERAA24 reports a higher LOLE of 5.4 hours (1.3 GWh EENS) in 2030**, versus 1.1 hours (0.8 GWh EENS) for ERAA24. **This trend reverses in 2035, where ERAA24 shows a lower LOLE** of 6.3 hours (2.9 GWh EENS) compared to 9.2 hours (15.7 GWh EENS) in MLZ25.
- In 2030, the higher LOLE in ERAA 2024 can be explained by **lower storage** (battery & LDES) and **interconnection capacities**.
- In 2035, the lower LOLE in ERAA24 is mainly driven significantly by **higher gas and DSR capacities**, which offset the scenario's lower interconnection and storage capacities.

Source: *Compass Lexecon analysis based on Tennet MLZ 2025.*

2.3

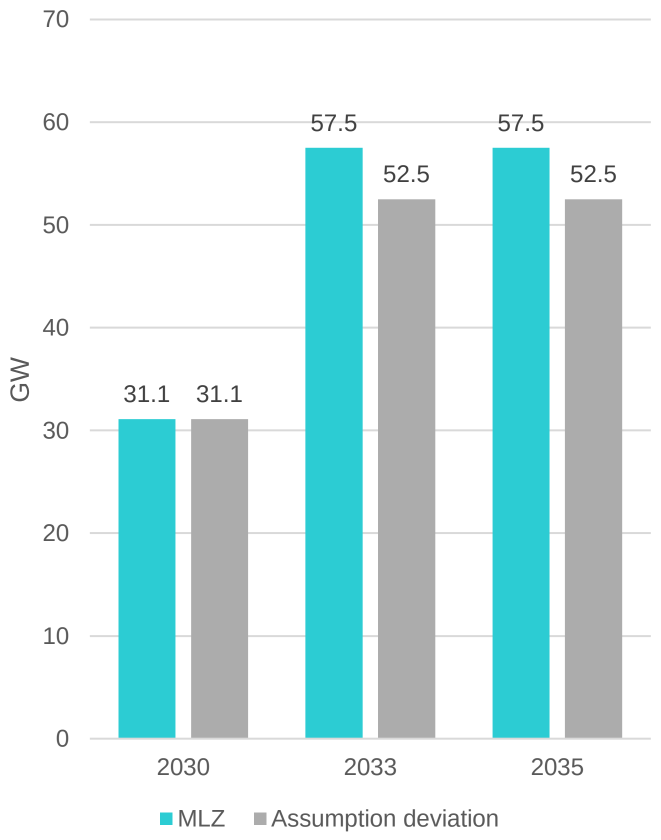
Our sensitivity analysis of the Dutch adequacy assessment

Overview of Compass Lexecon sensitivity analyses to key risks affecting the adequacy outlook

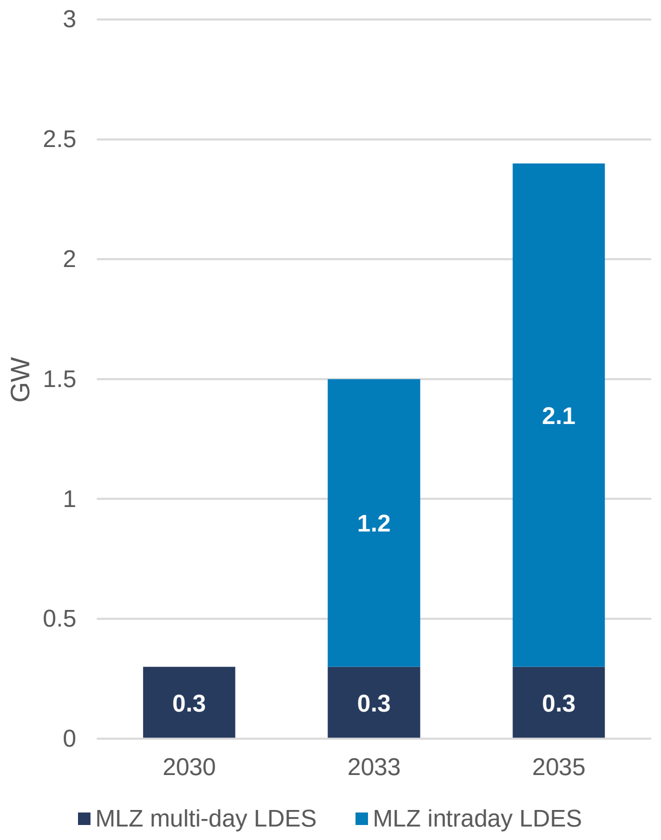
Scenario	Target year	Description
CL base case with all deviations from MLZ25	2030, 2033 & 2035	Assumption aligned with MLZ25 except the 3 assumption deviations: 1. 5GW lower German gas capacity in 2033 & 2035 2. Removal of multi-day and intraday LDES 3. Delay of LionLink's commissioning date from 2030 to 2033
CL only with German gas deviation	2033 & 2035	Assumption aligned with MLZ25 except the German gas assumption deviation
CL only with LDES deviation	2030, 2033 & 2035	Assumption aligned with MLZ25 except the LDES assumption deviation
CL only with LionLink deviation	2030	Assumption aligned with MLZ25 except the LionLink assumption deviation
CL adequate scenario Thermal/CCGT	2033 & 2035	CL base case + additional CCGT capacity (similar results can be expected for other dispatchable thermal technologies) to meet the 4h LOLE reliability standard
CL adequate scenario DSR	2033 & 2035	CL base case + additional DSR capacity to meet the 4h LOLE reliability standard
CL adequate scenario 4h BESS	2033 & 2035	CL base case + additional 4h battery capacity to meet the 4h LOLE reliability standard
CL adequate scenario LDES	2033 & 2035	CL base case + LDES capacity to meet the 4h LOLE reliability standard

In our base case scenario, we implemented three assumption deviations compared with TenneT's MLZ25 base case to reflect adequacy risks

German gas capacity (GW)



Dutch LDES capacity in MLZ25 (GW)



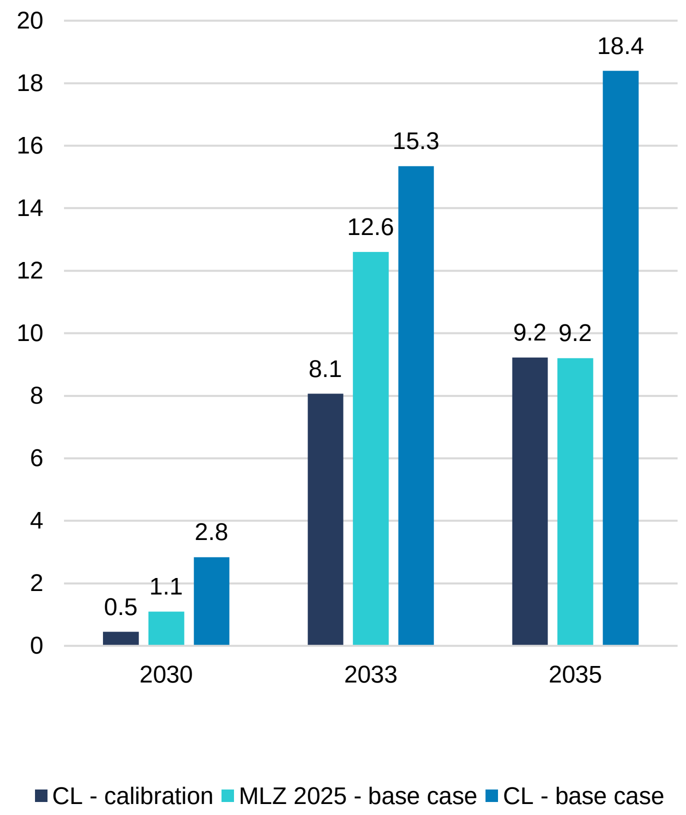
- In our base case scenario, we **use the same assumptions** as TenneT's MLZ25 study **except the following assumption deviations** to reflect risks related to the Dutch adequacy:
  - **Deviation 1: reduction** of **German gas capacity** from 57.5 GW to 52.5GW
  - **Deviation 2: Removal** of all **LDES** including multi-day LDES & and intraday LDESin the Netherlands
  - **Deviation 3: Delay** of the **LionLink** commissioning date from 2030 to 2033

Target years affected by the deviations

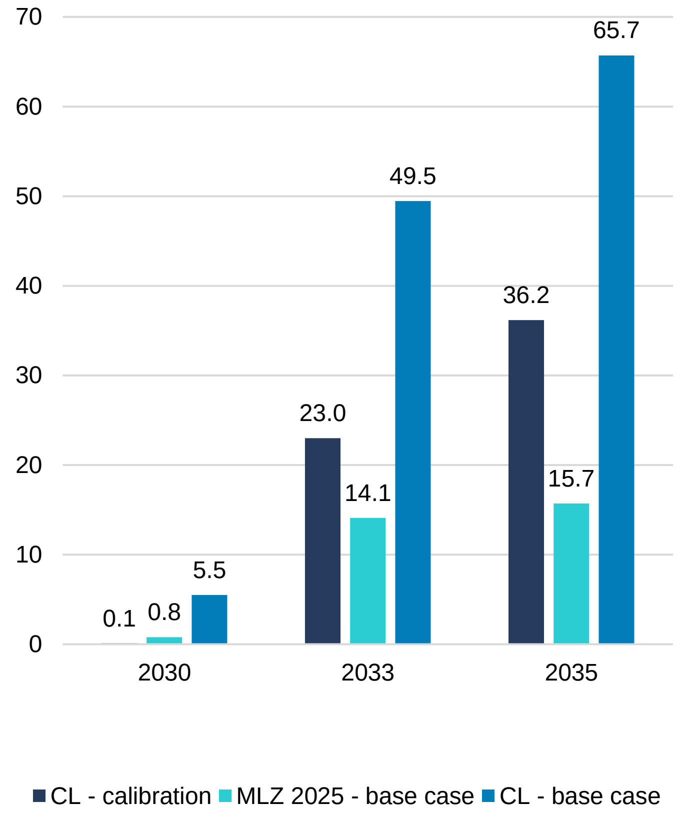
	German gas capacity	NL LDES	LionLink
2030		X	X
2033	X	X	
2035	X	X	

Compared to CL calibration runs, the assumption deviations in CL base case runs increase the LOLE estimates for the 3 target years

NL LOLE (h)



NL EENS (GWh)



- The assumption deviations in CL base case runs **increase the LOLE estimates for the 3 target years**:
  - In 2030, the higher LOLE is still below the 4h LOLE criteria.
  - In 2033 & 2035, the LOLE is almost doubled compared to the calibration runs and is also higher than MLZ 2025.

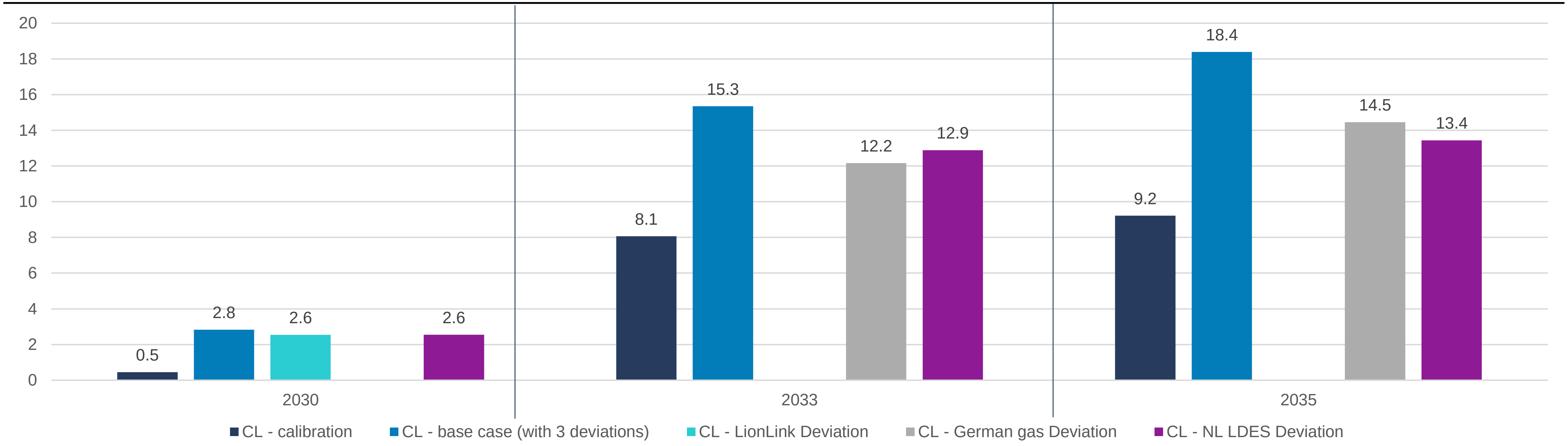
Target years affected by the deviations

	German gas capacity	NL LDES	LionLink
2030		X	X
2033	X	X	
2035	X	X	

Note: *CL results are with an "average" outage pattern.*

For 2033 & 2035 where the LOLE is above 4h, the impact of the German gas and LDES deviations is of a comparable order of magnitude

NL LOLE (h)

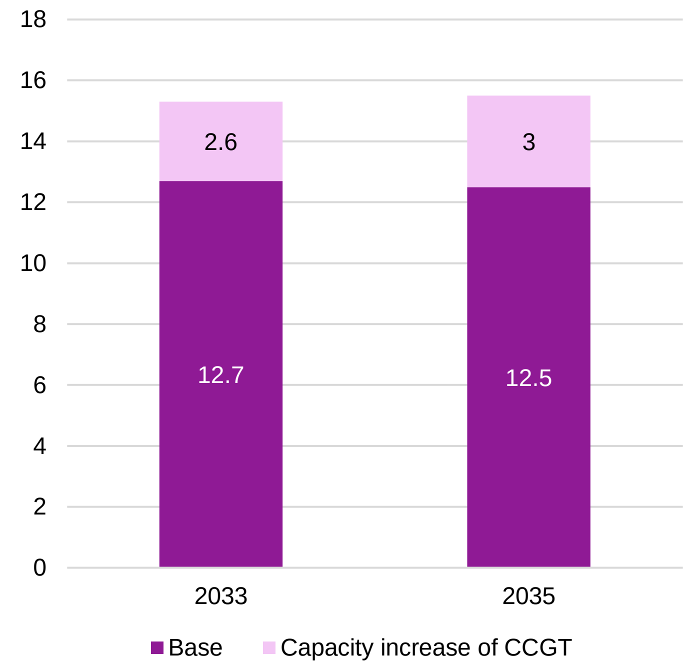


- The impact of an individual deviation shows not to be linear; the cumulative impact of deviations is not equal to the sum of isolated impact of each separate deviation.
- For 2030, the LOLE impact of the LionLink and LDES deviations is of a comparable order of magnitude and about 90% of the LOLE of both deviations combined.
- For 2033 & 2035, the LOLE impact of the German gas and LDES deviations is of a comparable order of magnitude and about 50-60% of the LOLE impact of both deviations combined (relative to the CL-calibration scenario).

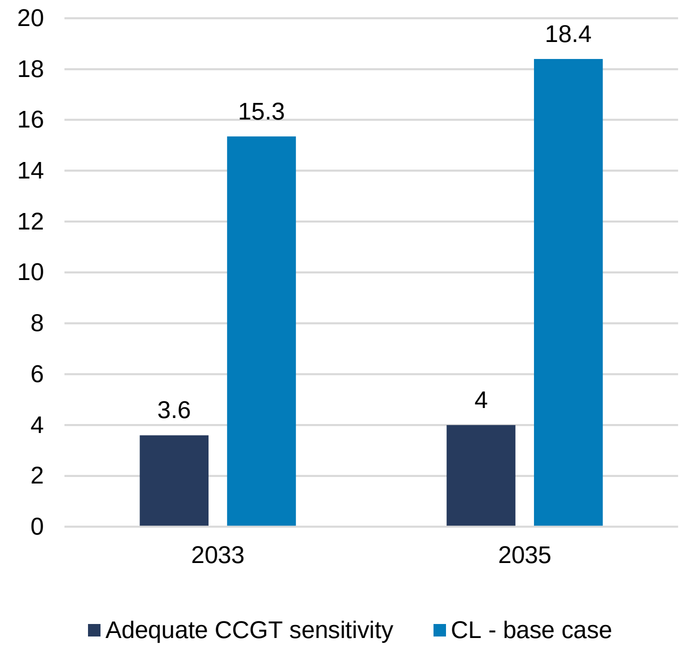
Note: *CL results are with an "average" outage pattern.*

Adequate scenario CCGT: Additional CCGT capacities of 2.6 GW and 3 GW would be required to reduce the LOLE to 3.6 and 4 hours, respectively in 2033 and 2035

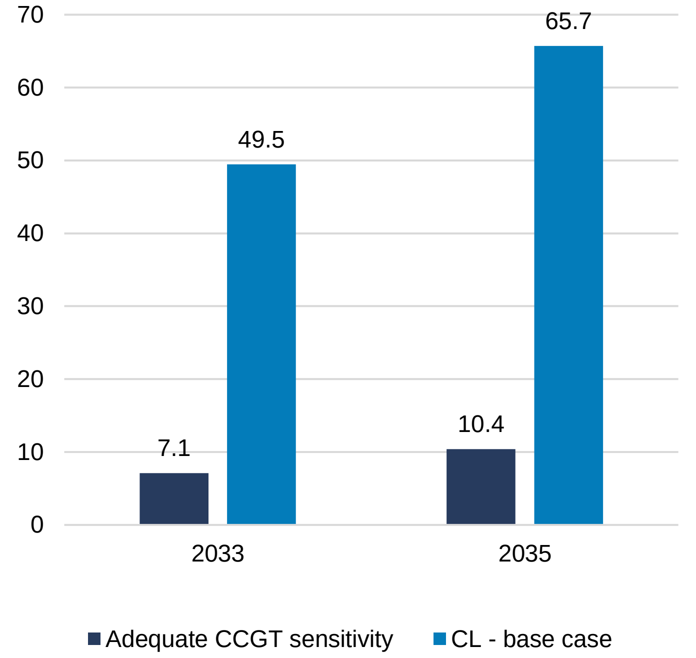
Installed capacity - CCGT (GW)



NL LOLE (h)



NL EENS (GWh)

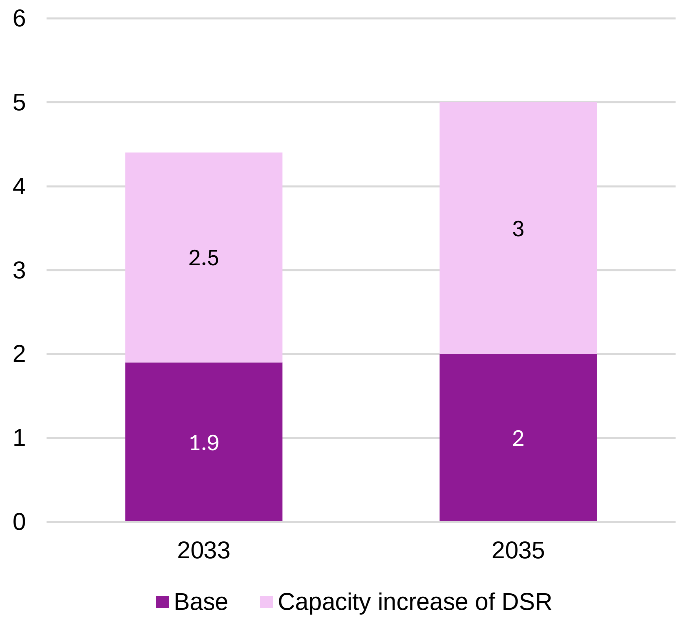


- MLZ25 scenario assumes gas-fired plant capacities of c.13 GW both in 2033 and 2035.
- **Additional CCGT capacities of 2.6 GW and 3 GW** would be required to reduce the LOLE to 3.6 and 4 hours, respectively in 2033 and 2035.
- These capacities could be acquired either through the extension of existing power plants or building of new power plants.
- We use CCGT as the thermal technology in our modelling, similar results can be expected for other dispatchable thermal technologies like coal plants being converted to biomass.

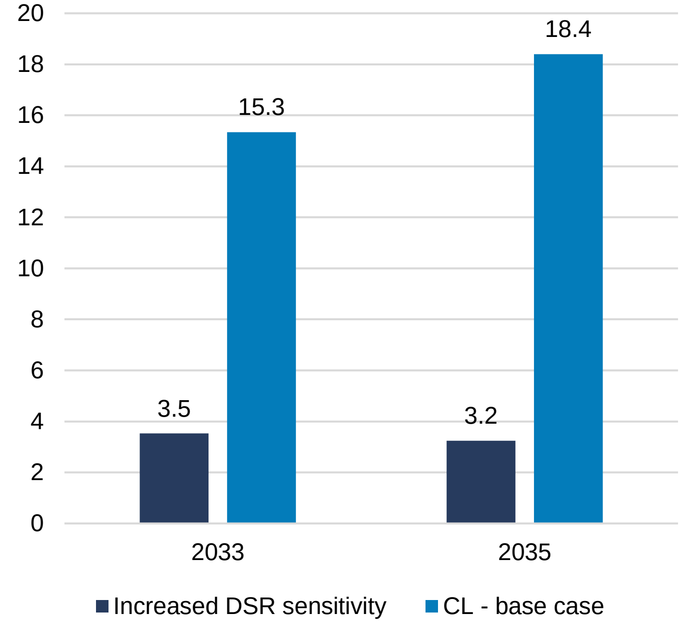
Note: *CL results are with an "average" outage pattern.*

Adequate scenario DSR: Additional DSR capacities of 2.5 GW and 3.0 GW would be required to reduce the LOLE to 3.5 and 3.2 hours, respectively in 2033 and 2035

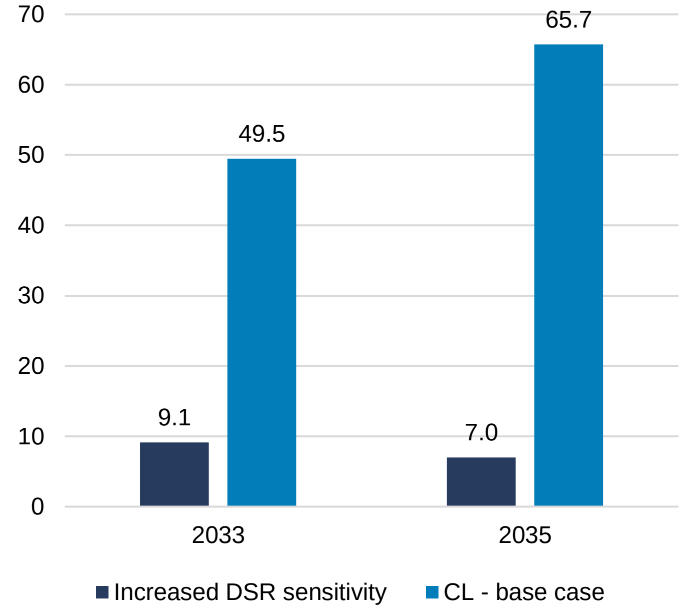
Installed capacity – DSR (GW)



NL LOLE (h)



NL EENS (GWh)

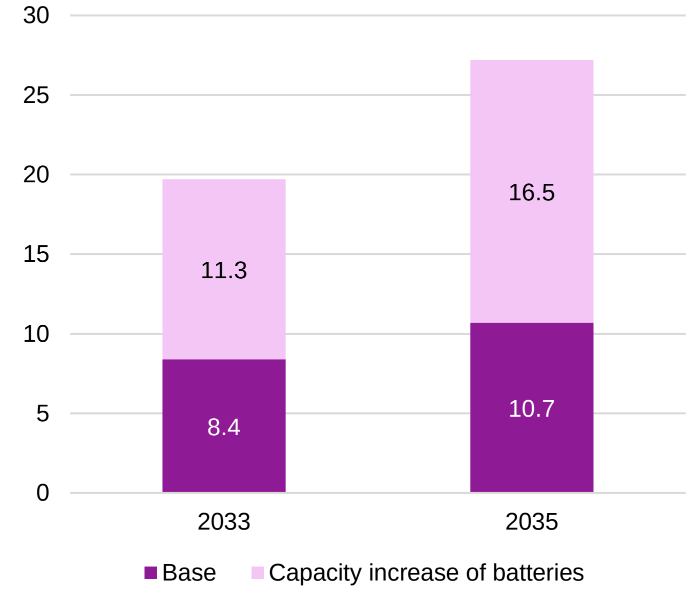


- MLZ25 assumes DSR capacities of 1.9 GW in 2033 and 2.0 GW in 2035. **No operational constraints** such as max activation duration or max yearly capacity factor **are considered for DSRs in MLZ 2025**. In other words, **DSR flexibility could be overestimated**.
- **In theory, additional DSR capacities of 2.5 GW and 3.0 GW** would be required to reduce the LOLE to 3.5 and 3.2 hours, respectively in 2033 and 2035. This would imply a capacity increase of more than 100%. Thus, it might not be realistic to rely solely on DSR to solve adequacy issues due to the uncertainties on its potential.

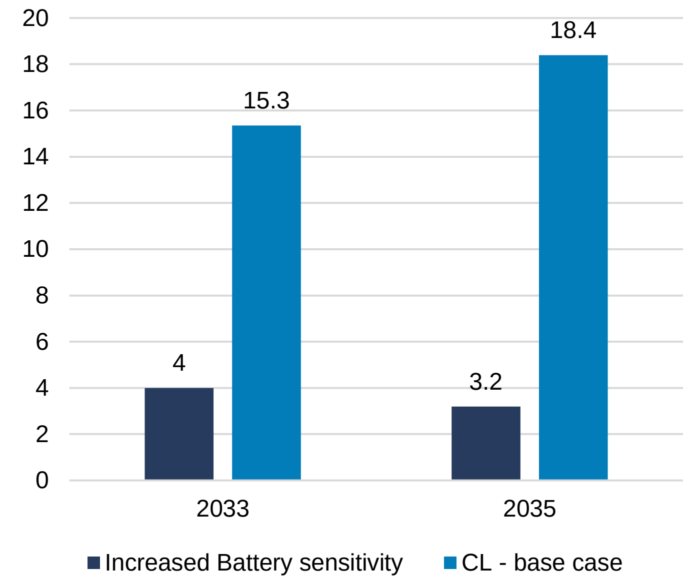
Note: *CL results are with an "average" outage pattern.*

Adequate scenario 4h BESS: Additional 4h BESS capacities of 11.3 GW and 16.5 GW would be required to reduce the LOLE to 4 and 3.2 hours, respectively in 2033 and 2035

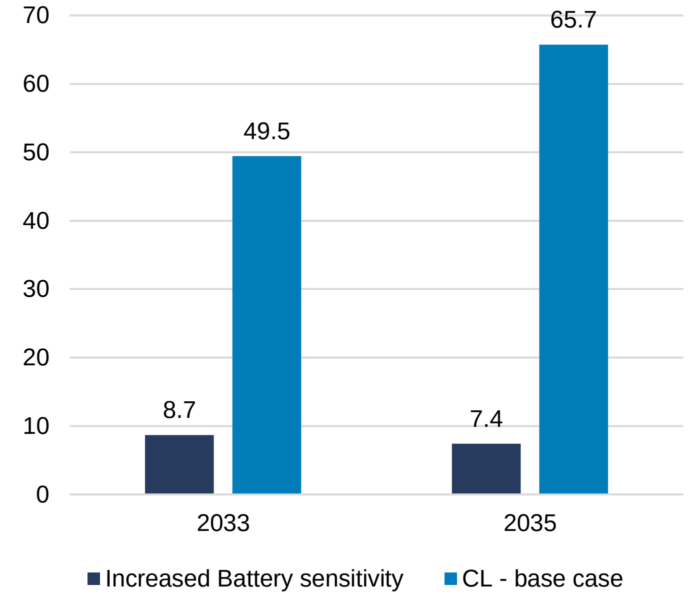
Installed capacity – 4h BESS (GW)



NL LOLE (h)



NL EENS (GWh)

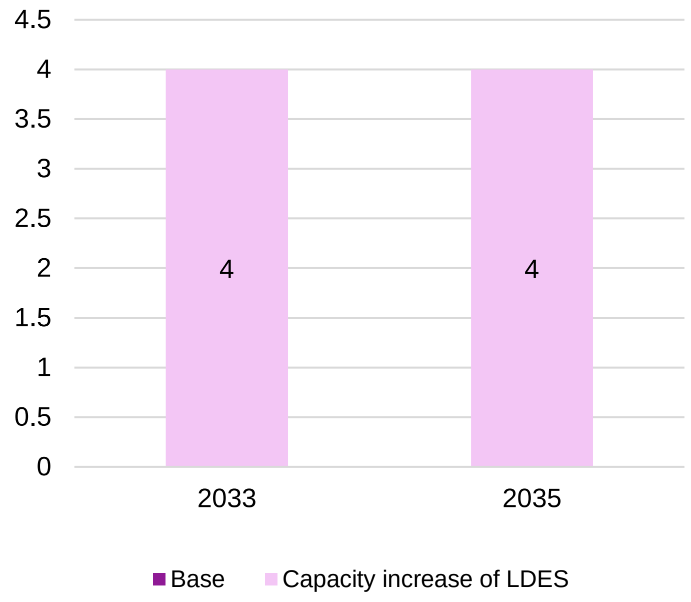


- In MLZ25, in addition to 2h batteries (V2G and household), 4h battery capacities (co location + large scale) reach 8.4 GW and 10.7 GW in 2033 and 2035. In this adequate scenario, we only consider additional 4h large scale batteries.
- **Additional 4h battery capacities of 11.3 GW and 16.5 GW** would be required to reduce the LOLE to 4 and 3.2 hours, respectively in 2033 and 2035.
- Compared with the first two adequate scenarios (Gas & DSR), **significantly higher battery capacities** would be needed to bring the LOLE to comparable levels. This is because loss of load tends to occur in periods with high demand or/and low wind generation. Such periods can last days while due to the **short storage duration**, the same installed capacity of 4h batteries' adequacy contribution is much lower than that of DSR/gas plant.

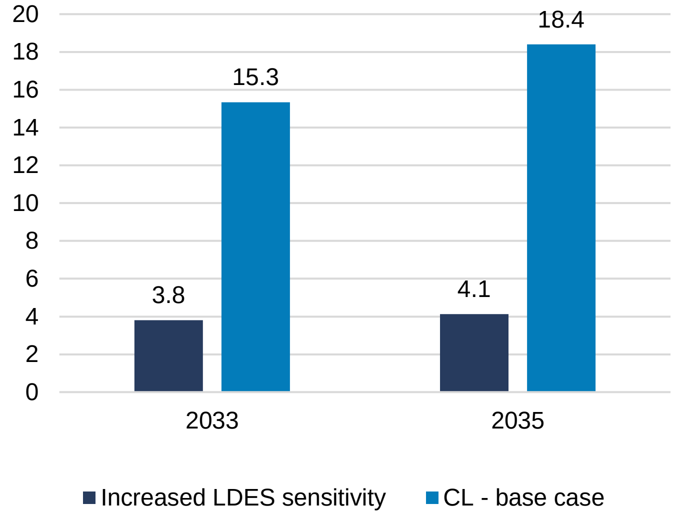
Note: *CL results are with an "average" outage pattern.*

Adequate scenario LDES: 4.3 GW of 12h LDES and 4.5GW of 16h LDES would be required to reduce the LOLE to 3.8 and 4.1 hours, respectively in 2033 and 2035

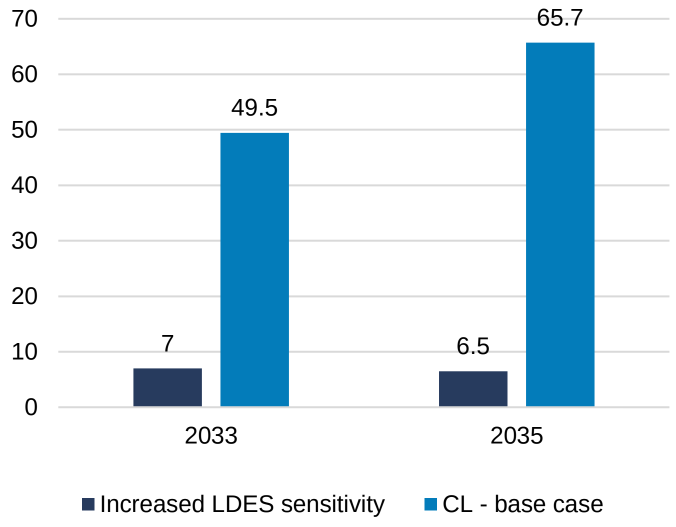
Installed capacity – 12h duration in 2033, 16h duration in 2035 (GW)



NL LOLE (h)



NL EENS (GWh)



- Both multi-day and intraday LDES are included in MLZ25 but are removed in our base case as one of the assumption deviations due to technical and other uncertainties.
- In this adequate scenario, we consider **intraday LDES assuming a duration of 12 hours in 2033 and 16 hours in 2035** to be in line with MLZ25.
- Additional 4.3 GW 12h LDES and 4.5GW 16h LDES would be required to reduce the LOLE to 3.8 and 4.1 hours, respectively in 2033 and 2035. Although these capacities are higher than firm capacities needed in other scenarios (such as DSR or gas-fired generation), they are significantly lower than capacities needed in the 4h battery adequate scenario thanks to LDES's longer duration.
- Under these assumptions, the EENS decreases from 49.5 GWh to 7 GWh in 2033 and from 65.7 GWh to 6.5 GWh in 2035.

Note: *CL results are with an "average" outage pattern.*

3.

Potential options in the Netherlands to bridge the adequacy gap

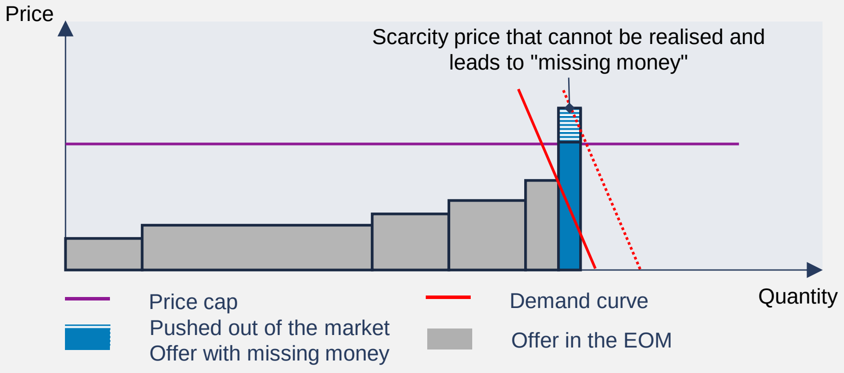
3.1

Capacity remuneration mechanisms: theory and practice

The investment incentives in the energy-only market may be insufficient to reach the socially desired level of adequacy (reliability standard)

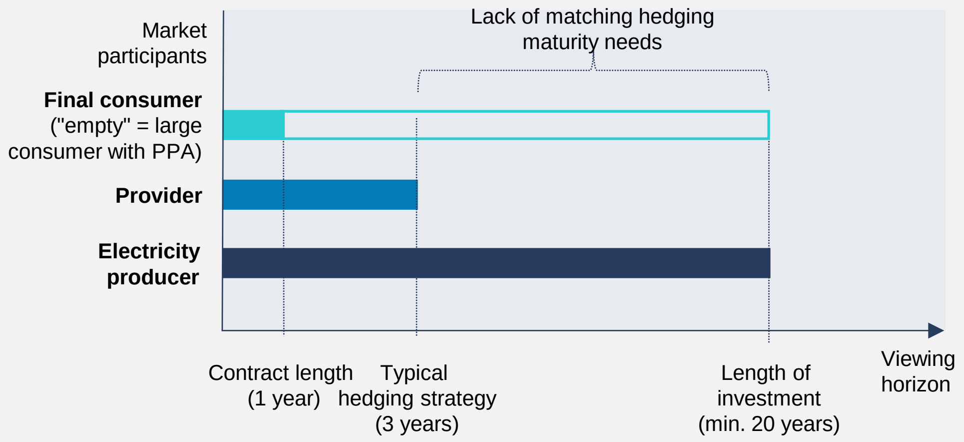
Missing money and missing market problem

- Companies **typically cannot realise** the actual value of their generation capacity **on the energy-only market (“EOM”)** due to**:**
  - Electricity prices do not reach the actual willingness to pay during scarcity hours (and/or interventions in the market can occur during those moments)
  - Increasing (subsidised) RES feed-in leading to low prices
  - No free price formation on reserve and redispatch markets



Lack of matching hedging needs

- While suppliers are particularly interested in **hedging for the duration of the electricity supply contract**, it is crucial for electricity producers to **hedge their investment** against price risks over a longer period of time.
- These different requirements lead to a discrepancy (lack of matching maturities) between the hedging needs of suppliers (consumers) and producers (suppliers).

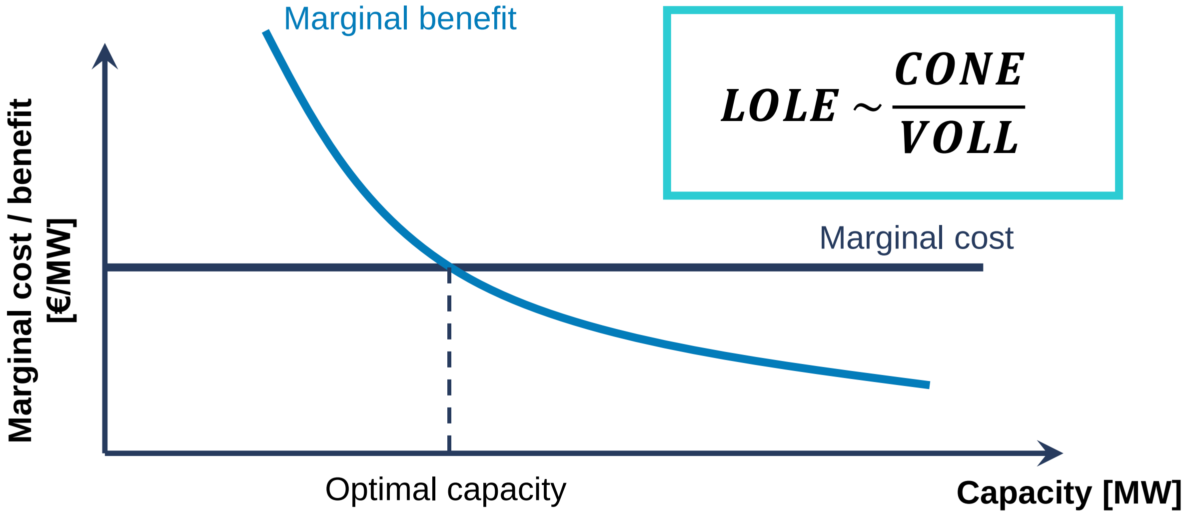


A CRM can lead to a more efficient distribution of risk between investors and consumers, as risks and corresponding capital costs are reduced.

According to the EU Electricity Regulation, if the resource adequacy assessment shows risks to adequacy, a CRM might be introduced

- According to the EU Electricity Regulation, Member States need to set the economically optimal **Reliability Standard:**
  - setting the LOLE target, calculated from **Cost of New Entry** (“CONE”) and VOLL
  - As an example and as a first approximation, for CONE ~ 60,000€/MW and VOLL~ 20,000€/MWh, the Reliability Standard is defined by a LOLE target of ~ 3 hours
  - ACER RS Methodology requires the **Reference Technology** providing the LOLE for the Reliability Standard to have **sufficient capacity resource potential** so that it can be built in a sufficient amount to ensure the targeted adequacy level.
  - The Methodology requires that the entity performing the calculation must monitor whether LOLE is aligned with the marginal value of EENS, however no method is provided to perform this analysis within the methodology.
- **Resource Adequacy Assessment** is the modelling exercise to assess the future LOLE taking into account actual system and market conditions.
- In case the Resource Adequacy Assessment indicates that the LOLE exceeds the reliability standard, the introduction of a **CRM** can be considered to resolve the mismatch.

Economic equilibrium determining the Reliability Standard

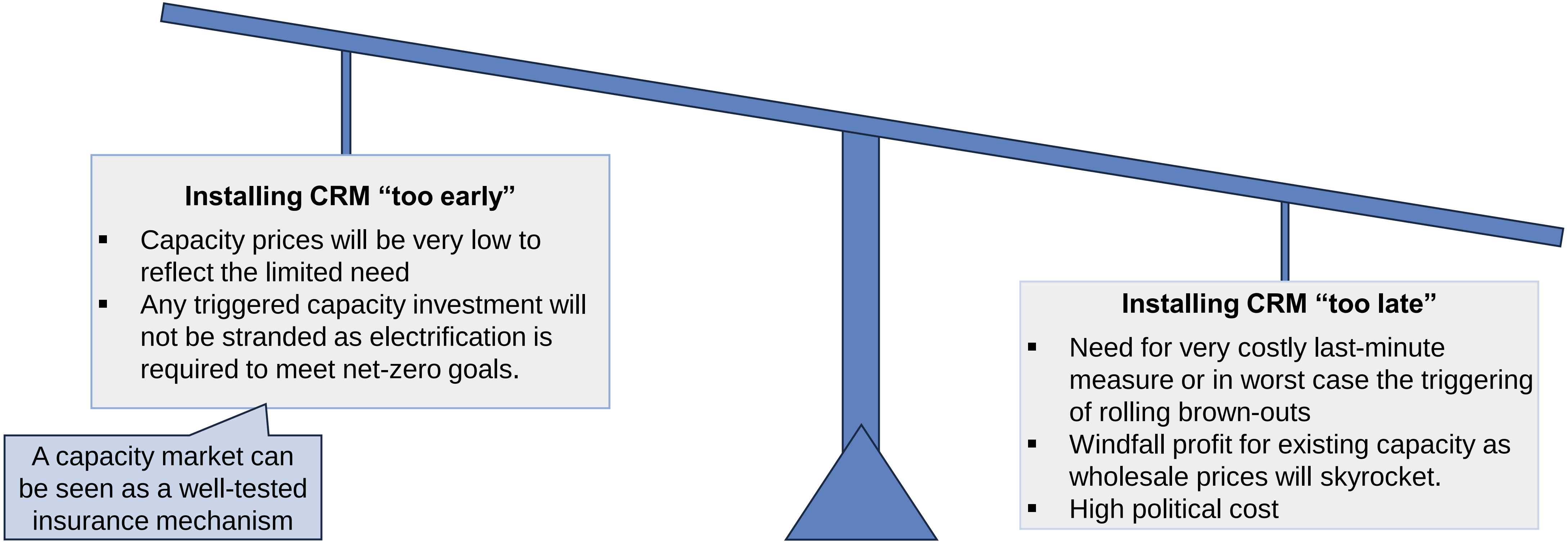


$$LOLE \sim \frac{CONE}{VOLL}$$

Source: *ACER, ACER Decision on the Methodology for calculating the value of lost load, the cost of new entry, and the reliability standard: Annex I, 2 October 2020 (link).*

CRMs can be seen as an insurance mechanism: it is significantly less costly to be too early than too late in supporting the required investments

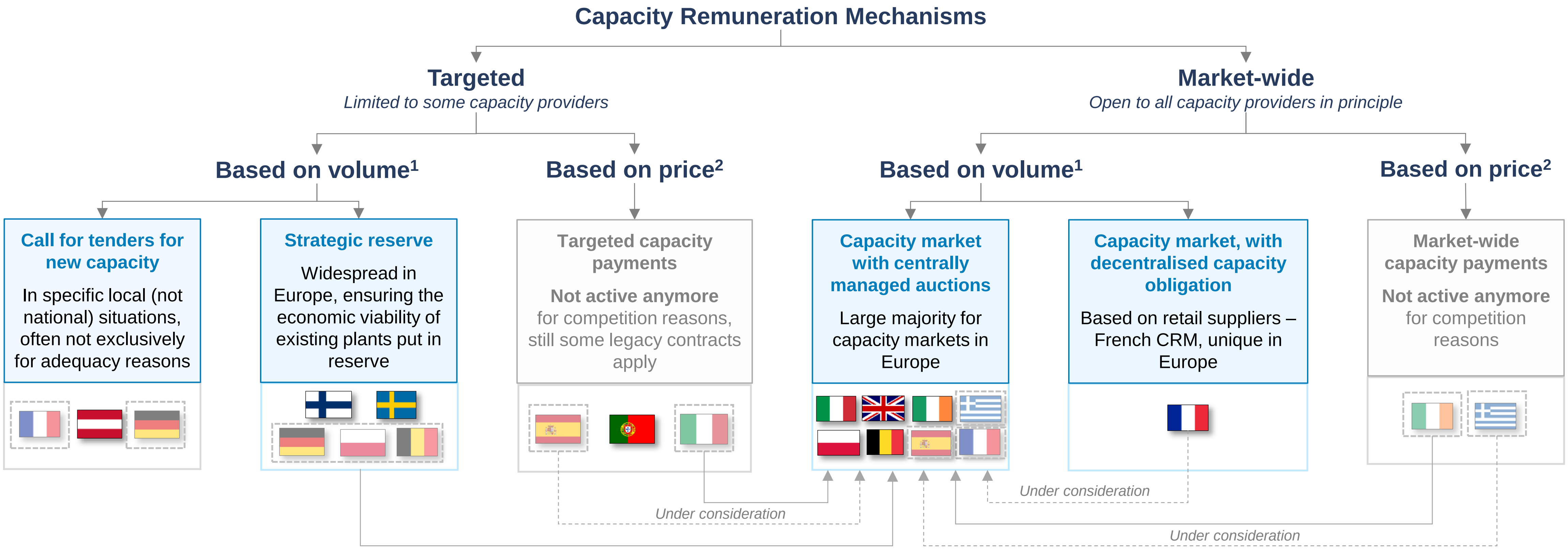
- An adequacy assessment is probabilistic, hence whether not introducing a CRM would lead to an exceedance of the LOLE-threshold is always uncertain. However, it can be argued that it is significantly less costly to be too early than to late in implementing a CRM.
- The implementation of a CRM is expected to take 3-5 years, and increasingly constructing new capacities takes longer due to supply chain issues.
- The Netherlands is a “late mover” which has the advantage that best practices in other countries can be learned from but the disadvantage that some potential investments have already opted to be deployed in neighbouring countries.



3.2

Trends in the neighbouring countries and EU regulatory framework

Over the past decade, many EU countries introduced CRMs with different designs – with a recent trend towards market-wide centralised CM



Note: (1) Fixed volume and market-determined capacity remuneration price; (2) Capacity remuneration price fixed administratively. For Germany, the new government plans to introduce a market-oriented capacity mechanism, however, the detailed design is not yet known.

Source: *Compass Lexecon analysis.*

CRM’s objectives have evolved from managing capacity exit, to supporting timely investment in required new firm capacity

A brief history of capacity mechanism design trends

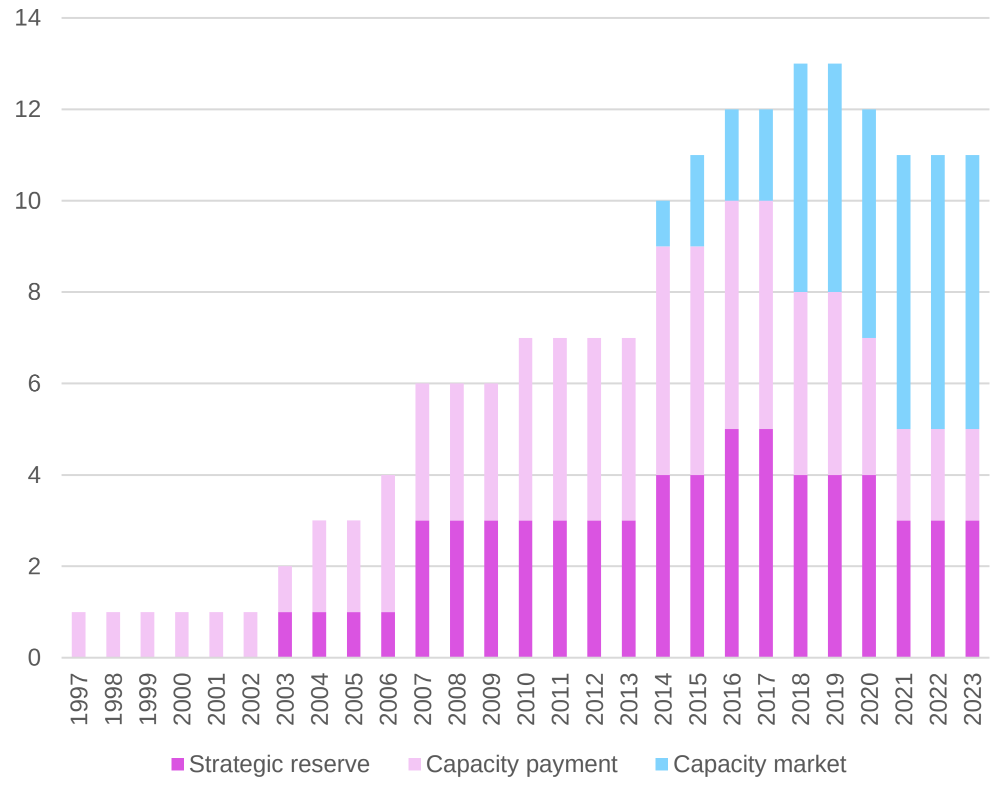
- **Early 2000s and 2010s**: overcapacity situation in Europe, leading to economic viability issues and a risk of uncoordinated exit of ageing thermal plants.

  → Implementation of **strategic reserves in some countries** (e.g. Germany, Belgium) made it possible to manage the exit of old thermal plants while maintaining security of supply.

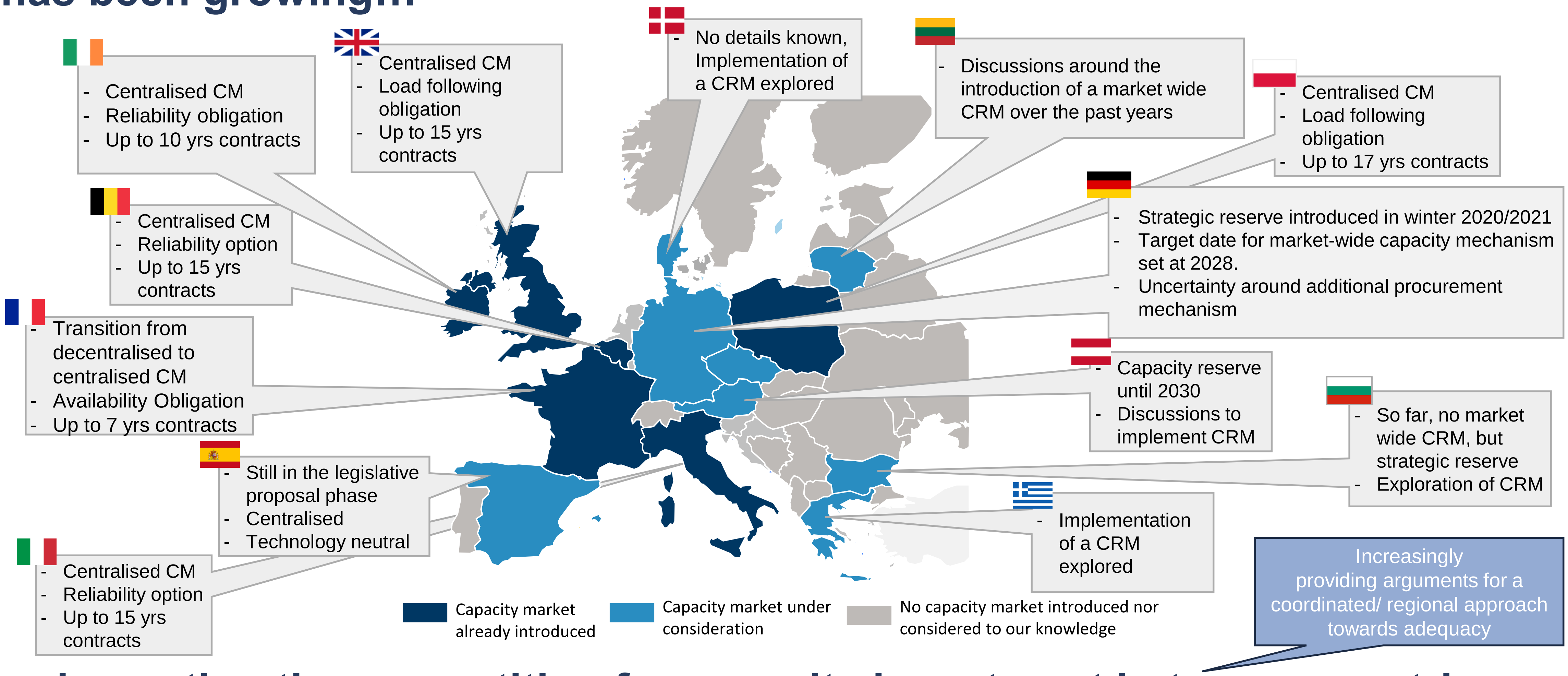
- **From 2010 to today**: revived need for investment in new capacity to address “energy-only” markets' failures. **Most cited reasons driving the introduction of capacity markets include:**
  - “Missing money” due to imperfect wholesale market design
  - Impact of RES on electricity price
  - Limited liquidity in forward markets (>3y) and challenges to finance merchant investments
  - Policy and regulatory uncertainty

Outlook for CRMs: In addition to triggering investment in new (decarbonised) firm capacity, growing intermittent RES create a challenge for addressing other system needs (including flexibility, ramping, congestion, inertia). Avoiding overcompensation and overcapacity resulting from CRM cumulation with upcoming schemes dedicated to DSR, storage and flexible assets is also key.

Growth in the number of capacity remuneration mechanisms in the EU + GB (1997-2023)



The number of EU countries introducing or considering introducing a CRM has been growing…



… impacting the competition for capacity investment between countries

Source: *Vector Renewables, The capacity market in Spain, 14 February 2025 (link); Energy Press, Capacity market explored to support gas-fired power plants, 3 June 2025 (link); Enerdata, Lithuania, Latvia and Estonia ready to disconnect from Russian power grid, 6 February 2025 (link).*

The implementation of a CRM needs to follow several defined steps to secure State aid approval (1/2)

The CRM is considered State aid and requires clearance under the State aid guidelines and the Regulation 2019/943, which includes two elements:

- Demonstrating that the CRM satisfies the key criteria below, and
- Implementation plan for the reforms to address identified regulatory distortions and market failures (Article 20 of Regulation 2019/943)

Key State Aid criteria		Implications
1 Contribution to well-defined objective of common interest 2 Need for State aid intervention	**Justification**	▪ Must be clear need for state intervention and the objectives must be clearly defined ▪ Objective must be consistent with phasing out environmentally harmful subsidies
3 Appropriateness of the aid measure 4 Incentive effect 5 Proportionality of the aid	**Proportionality and design**	▪ Aid should not change the behaviour of market players and be non-discriminatory ▪ Aid to the minimum: the amount paid should tend to zero as capacity available approaches the required level ▪ Must have reasonable rates of return and competitive bidding process is encouraged
6 Avoidance of major undue negative effects on competition and trade between member states 7 Transparency of aid	**Impact on competition and internal market**	▪ Operators from other member states should be allowed to participate ▪ Negative effects on the internal market should be avoided ▪ Should not reduce incentives to invest in interconnection

Source: *Compass Lexecon analysis.*

The implementation of a CRM needs to follow several defined steps to secure State aid approval (2/2)

The CRM is considered State aid and requires clearance under the State aid guidelines and the Regulation 2019/943, which includes two elements:

- Demonstrating that the CRM satisfies the key criteria, and
- Implementation plan for the reforms to address identified regulatory distortions and market failures (Article 20 of Regulation 2019/943):

Elements of the implementation plan for market reforms

1. Removing regulatory distortions
2. Removing price caps
3. Introducing a shortage pricing function for balancing energy
4. Increasing interconnection and grid capacity
5. Enabling self-generation, energy storage, demand-side measures and energy efficiency
6. Ensuring cost-efficient and market-based procurement of balancing and ancillary services
7. Removing regulated prices where required

Source: *Compass Lexecon analysis.*

The Electricity Market Design reform refines the key design issues for the implementation of a strategic reserve, CRM and flexibility mechanism

	Principles and requirements for CRM in accordance with Articles 21 and 22 of the CEP (Regulation 2019/943)	The reform of the electricity market design affects several key elements of the CRMs
Conditions for a CRM	• CRMs **are limited in time** (max. 10 years) • The CRM is a last resort • **Mandatory expiry** of the mechanism if no new contracts are concluded in 3 consecutive years	• CRMs will become a **"structural component"** of the electricity market and not an obligation to phase out • Streamlining the CRM implementation process
Selection of a CRM design	• Focus on **strategic reserves** • Other measures (a market-wide CM) **only if the** strategic reserve is not able to solve the resource adequacy problem	• Focus on non-fossil flexibility measures, e.g. flexibilization of demand and energy storage, through existing CRM or possibly **flexibility mechanisms**

Limiting CO2 emissions	• Exclusion of capacities from CRM remuneration depending on the start of production...
	  ◦ **after July 04, 2019:** 550 g CO2 / kWh
	  ◦ **before July 4, 2019:** 550 g CO2 / kWh and 350 kg CO2 / year / installed kWe
		• Encouraging the introduction of other green criteria in CRM
		• **Temporary exemption** from the CO2 emissions limit for existing capacity mechanisms

Source: *Journal of the European Union, Regulation (EU) 2019/943 of the European Parliament and of the Council, 5 June 2019 (link); Journal of the European Union, Regulation (EU) 2024/1747 of the European Parliament and of the Council, 13 June 2024 (link).*

3.3

Qualitative assessment of options

Summary of the key risks and uncertainties leading to adequacy concerns in the Netherlands

Structural drivers of adequacy concern → **Impact on the adequacy situation**

1 Coal exit set in 2013, uncertain commercial outlook for aging Dutch thermal fleet	Likely exit of important share of existing thermal capacity
2 Highly risky investment environment for entry of merchant dispatchable capacity	Very unlikely entry of any merchant dispatchable capacity
3 Uncertain German capacity expansion, timing new interconnection with GB and readiness of innovative technologies	Additional supply uncertainty that is largely out of control of NL
4 Expectations of rising demand in NL	Increased need for extending existing capacity and new entry

Complicating factors for investment → **Impact on investment decisions**

I Increasingly volatile wholesale prices and possible price intervention	Increases risk and/or cost for generation leading to a reduction in new entry and an increase in exiting of existing supply
II Increasing gas withdrawal and electricity injection tariffs	
III Uncertain decarbonisation requirements	
IV Uncertain nuclear phase-in and other low-carbon technology procurement policies	
V Uncertainty around the degree of the anticipated demand growth	
VI Capacity markets in neighbouring countries	Higher investment appeal in neighbouring countries

Requirements for a least-cost mechanism to fill the "adequacy gap":

A. **Quick** to implement

B. **Well-tested**

C. **Reduce investment risk** driven by I, II, III, IV and V

D. Create a **level-playing field for new investment across neighbours** (VI)

E. **Technological neutrality**, i.e. not relying on forecasts of the technology readiness of novel technologies. Also, avoiding 1 by providing exclusive support to existing generators can be a solution but potentially not the least cost solution.

F. **Robustness**, e.g. with respect to a potential delay of 4 or IV

G. **Limited procurement cost** of the mechanism

H. Overall positive **welfare impact**

A centralised market-wide CM has several advantages over an SR, importantly being a technology neutral solution

		Strategic reserve	Centralised market-wide capacity mechanism
	A Speed of implementation	Can be relatively quick	Longer implementation but acceleration possible
	B Well tested	Has been in place in many countries	In place in many countries
Dynamic efficiency	C De-risk investment	Only for capacity in SR, not addressing new investment	For existing and new capacity[1]
Dynamic efficiency	D Level-playing field across countries	Unaddressed, except for participating capacity	In place or planned in neighbouring countries
Dynamic efficiency	E Technology neutral	Focused on existing thermal, sometimes also includes DSR	Increasingly varying procurement mix which is shown to be required in NL
Dynamic efficiency	F Robust	Can lead to patchwork of mechanisms (e.g. in case of nuclear phase-in delay)	Can provide a fit-for-all solution, prices will reflect the severity of the adequacy concerns
Quantified	G Limit procurement cost	Lower due to limited to participating SR	Higher but varies per design and eligibility
Quantified	↓ Input		
Quantified	H Positive welfare impact	Outcome of the modelling	

See Slide 56 for case studies.

We consider the **static** welfare impact of a CRM, capturing the **dynamic efficiency** would require more extensive modelling and is therefore only qualitatively assessed.

Note: *(1) A CM as well reduces risk premia for retailers and overall collateral requirements due to lower wholesale price volatility under a CM relative to under an SR (see Slide 67).*

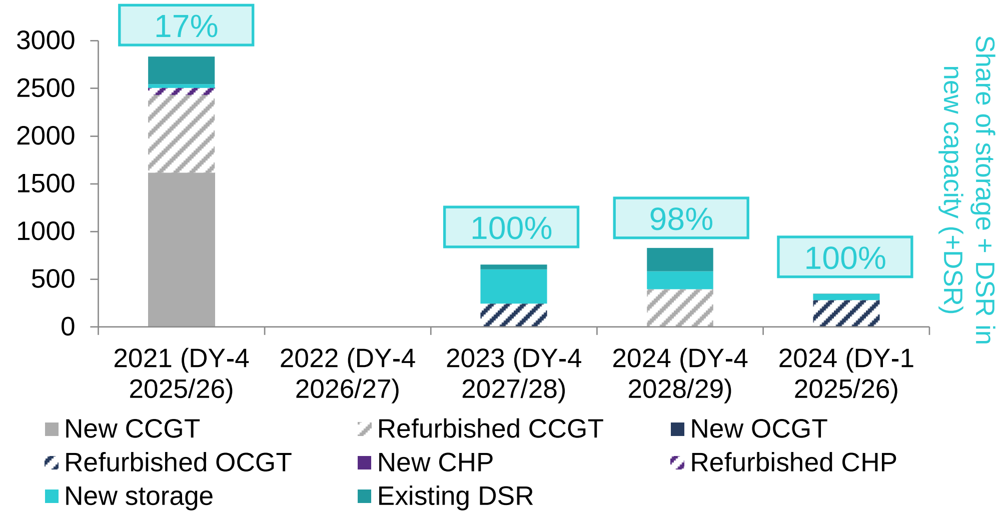
Complementing an SR with a flexibility contracting mechanism likely would mitigate some but not all concerns with an SR

	Criterion	Strategic reserve	+ Flex mechanism	Centralised market-wide capacity mechanism
	A Speed of implementation	Can be relatively quick	↑ Likely faster than CM	Longer implementation but acceleration possible
	B Well tested	Has been in place in many countries	↓ Relatively novel	In place in many countries
Dynamic efficiency	C De-risk investment	Only for capacity in SR, not addressing new investment	↑ For DSR + storage	For existing and new capacity[1]
Dynamic efficiency	D Level-playing field across countries	Unaddressed, except for participating capacity	0 No impact	In place or planned in neighbouring countries
Dynamic efficiency	E Technology neutral	Focused on existing thermal, sometimes also includes DSR	0 Not tech-neutral	Increasingly varying procurement mix
Dynamic efficiency	F Robust	Can lead to a patchwork of mechanisms	↓ Creates patchwork	Can provide a fit-for-all solution
Quantified	G Limit procurement cost	Lower due to limited to participating SR	↓ Adds costs	Higher but varies per design and eligibility
Quantified	(Input ↓) H Positive welfare impact	Outcome of the modelling		

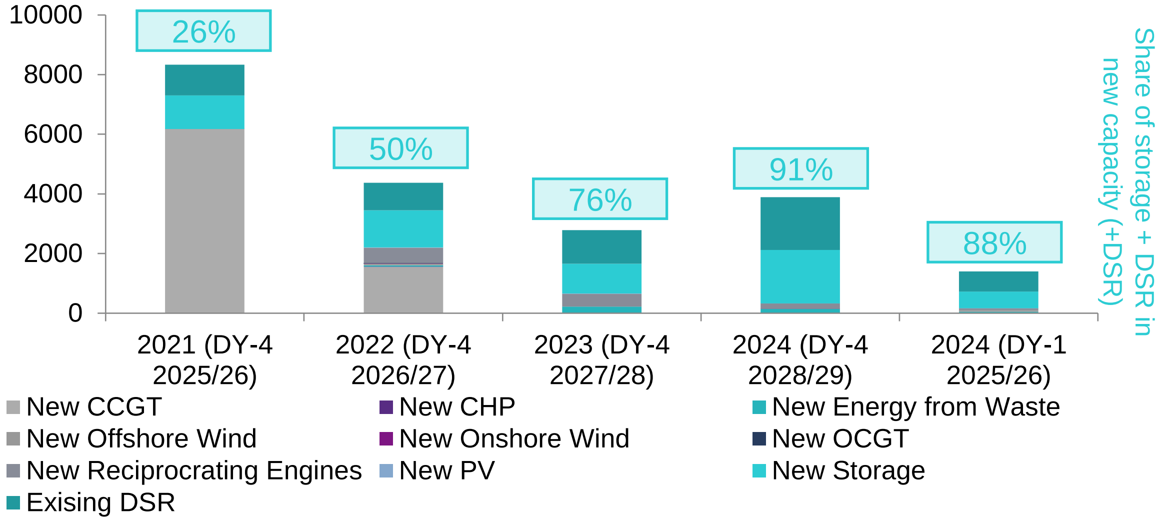
Note: *(1) A CM as well reduces risk premia for retailers and overall collateral requirements due to lower wholesale price volatility under a CM relative to under an SR (see Slide 67).*

A key advantage of a market-wide capacity mechanism is its technology neutrality, avoiding the need to pick the winners before these are known

New capacity awarded contracts in the Belgian CM, 2021-2024, MW



New capacity awarded contracts in the British CM, 2021-2024, MW



Note: for 2021 DY-4, "CCGT" includes all capacity classified as "gas".

In **Belgium**, while **gas-fired generation** represented the large majority of new capacity in the first auction, in more recent auctions **storage and DSR** are taking an increasingly important place.

In **GB**, as part of the Statutory Five-year review 2019/2024, the Department for Energy Security & Net Zero noted that "**gas powerplants and battery storage systems** are the largest proportion of new build capacity secured via the CM" and that "the deployment of a **range of technologies** through the CM, including **flexible** technologies, has also helped to **minimise the whole costs** of our electricity system."

- A centralised, market-wide CRM increasingly proves to result in investment in a **most cost-effective** technology mix.
- Looking ahead if the cost of **storage** and **demand response** technologies continues to decline, storage likely would naturally **outcompete** thermal capacity under a well-designed CRM. If this is not the case, other technologies will be selected.

Note: *DSR includes existing capacity.*
Source: *Elia, CRM Auction Results (link); NESO, Capacity Auction Results (link); Department for Energy Security and Net Zero, Capacity Market Statutory Five-year Review, December 2024 (link).*

3.4

Quantitative assessment of options

Our model-based impact assessment of different solutions to maintain adequacy in the Netherlands relies on the following quantitative KPIs

	Key output from analysis	Approach options
1	**Available capacity** and impact on investments in the Netherlands	Evaluate the impacts of market design options on available capacity by studying investment, retirement and mothball decisions in the Netherlands based on market revenues and avoidable costs (NPV)
2	**Security of supply** in the Netherlands	Impacts of market design options on security of supply, LOLE
3	**Costs of the CRM**: the procured volume and capacity price	The procurement costs of a capacity mechanism will depend on the specific parameters of the design elements and 1) capacity price, and 2) volume of contracted capacity which secure the Dutch reliability standard. This would have to potentially account for long-term contracts.
4	Impact on **energy prices** in the Netherlands and neighbouring countries	Hourly prices are simulated and used in quantifying social welfare
5	**Economic welfare impact in the Netherlands**	The economic welfare analysis quantifies total economic welfare and identifies potential distributional impacts: Consumer welfare (incl. energy price, capacity price, and the value of the Energy Not Served), producer welfare (profits from energy and capacity markets), and congestion rent

We consider the static efficiency of a certain mechanism, capturing the dynamic efficiency would require more extensive modelling. Hence, we qualitatively discuss those impacts (see previous section).

Economic assessment of market design options requires considering their impact on several elements of consumer and producer surplus

Methodology to estimate the net benefit of SR/CRM

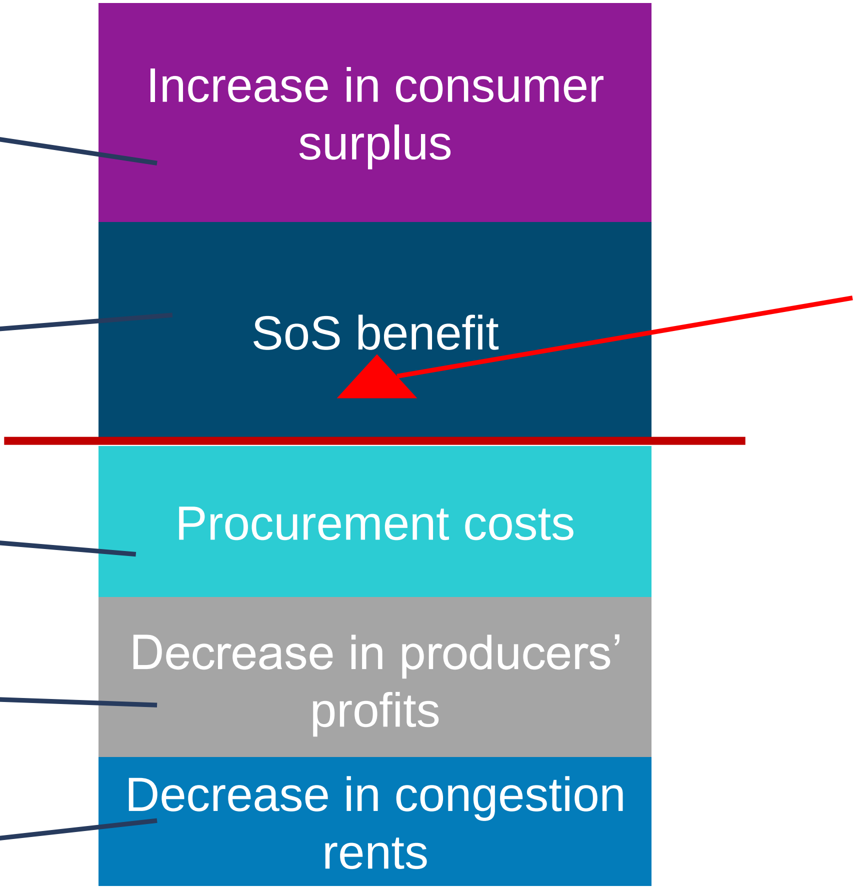
In case a market design reduces wholesale prices: consumers realise additional benefits from increase of the consumer surplus

Impacts of market design option on security of supply calculated as the difference in EENS evaluated at VOLL

Procurement costs of a capacity mechanism depends on the capacity price and volume of contracted capacity

In case a market design reduces wholesale prices: producers have lower wholesale market profits

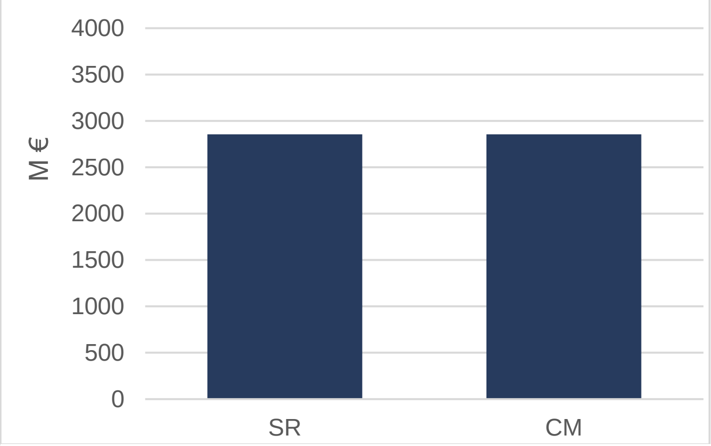
In case a market design reduces wholesale prices: congestion rents collected by TSOs decrease



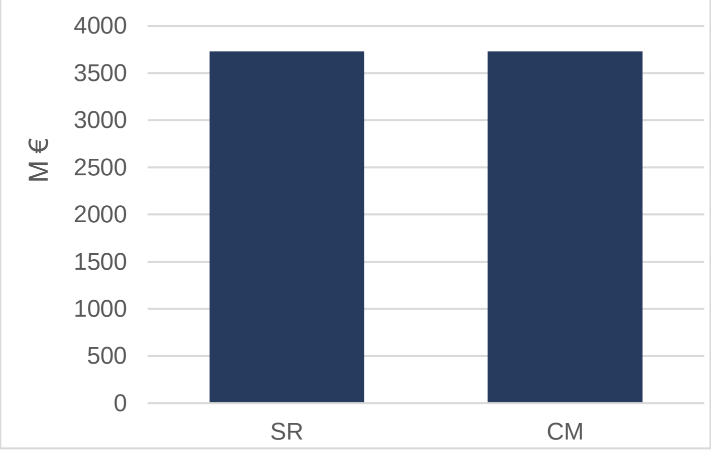
Net benefit : sum of surplus increases, net of surplus decreases caused by the CRM design option

The high VOLL estimated for the Netherlands (69k€/MWh) leads to a large SoS benefit of either an SR or CM compared to the status quo

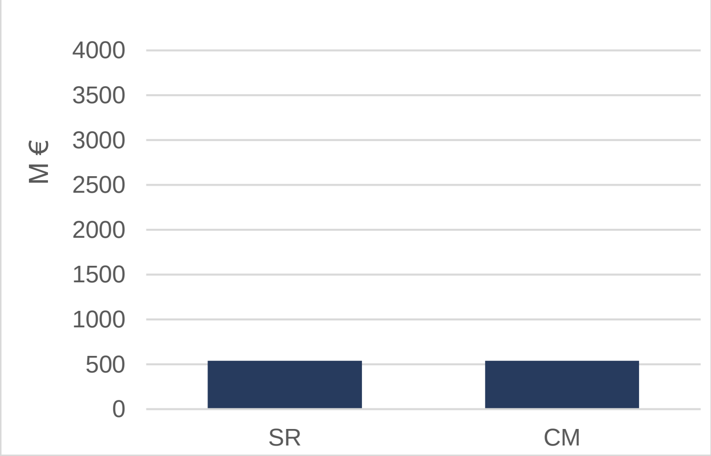
SoS benefits at 69€/kWh in 2033



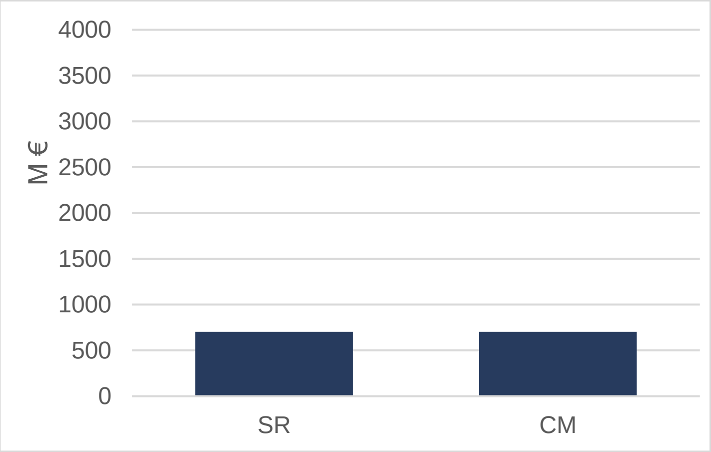
SoS benefits at 69€/kWh in 2035



SoS benefits at 13€/kWh in 2033



SoS benefits at 13€/kWh in 2035

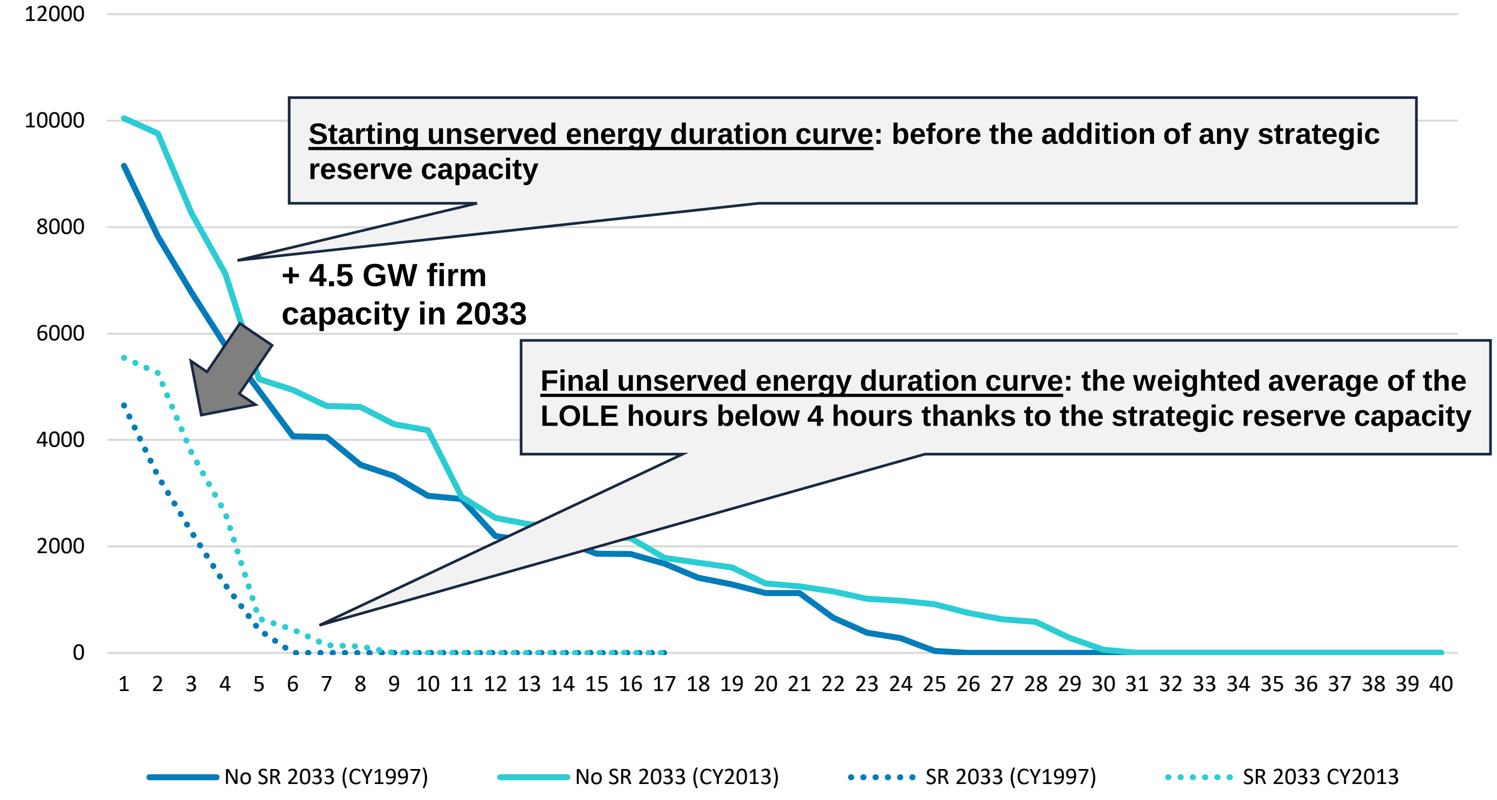


- The difference in EENS between the baseline and SR/CRM scenarios valued at the VOLL of 69€/kWh results in SoS benefits between c.3 and c.4 B€ per year in 2033 and 2035.
- The SoS benefits for both mechanisms are nearly identical by design as they are both dimensioned to reduce the LOLE under the 4h-threshold. For an SR this can be done as long there is enough existing capacity to reserve.
- If the VOLL in the Netherlands is reassessed at the level of Belgium or Germany of 13€/kWh, the SoS benefits would reduce to c.500-700 M€ per year.

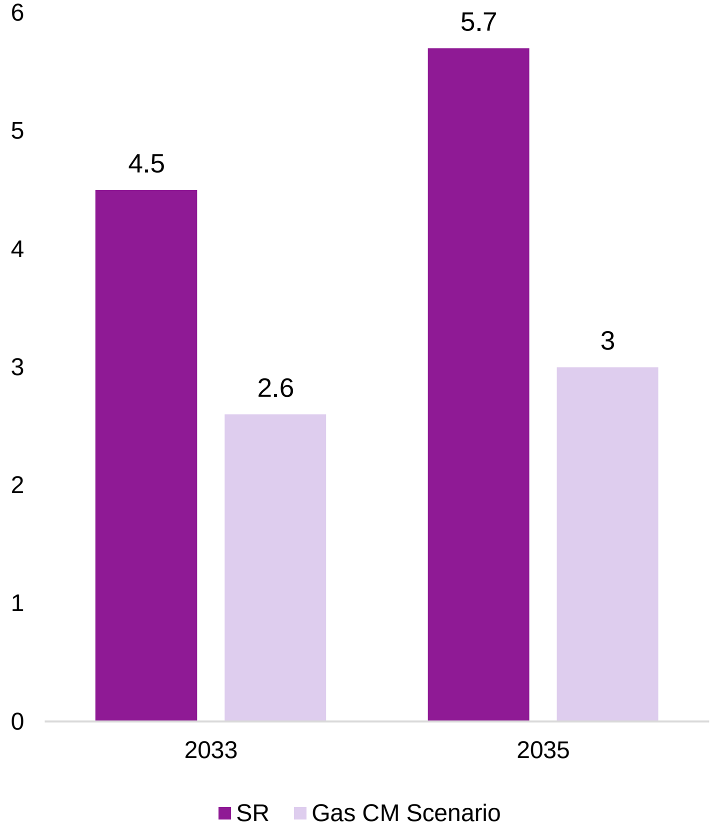
Note: *CL results are with an "average" outage pattern.*

SR and CM design options would require different additional volumes of capacity to reach the Reliability Standard

Unserved energy duration curve (2033) without and with SR capacity for two climate years ("CY")



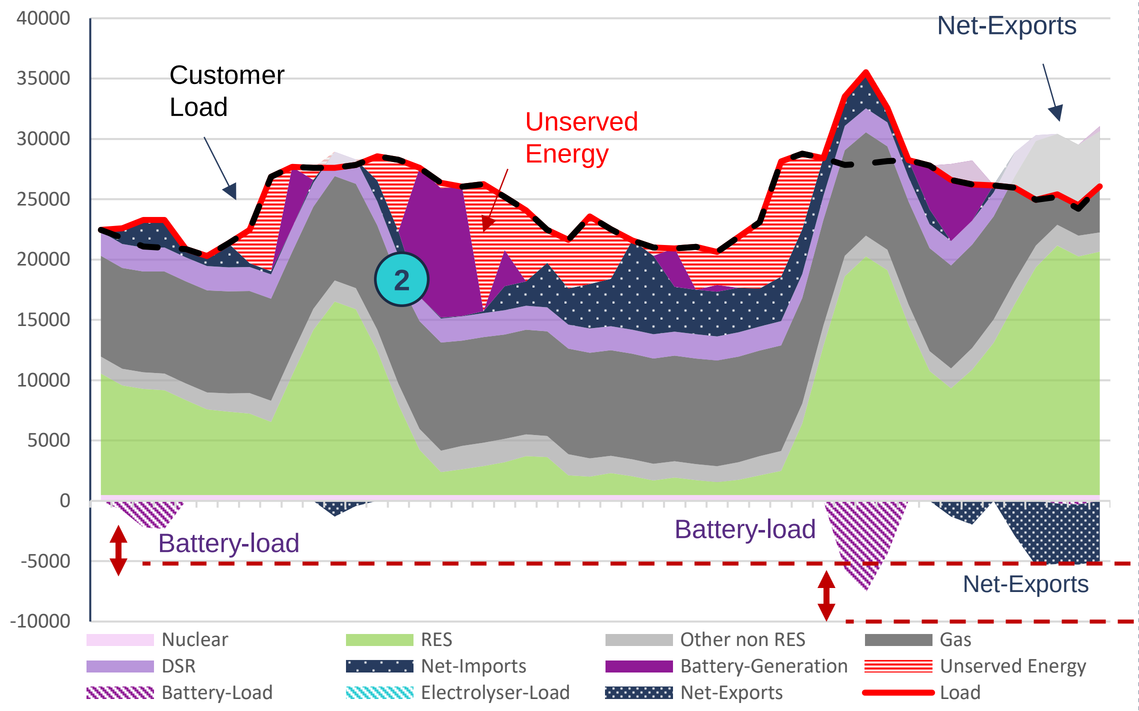
SR vs Adequate scenario



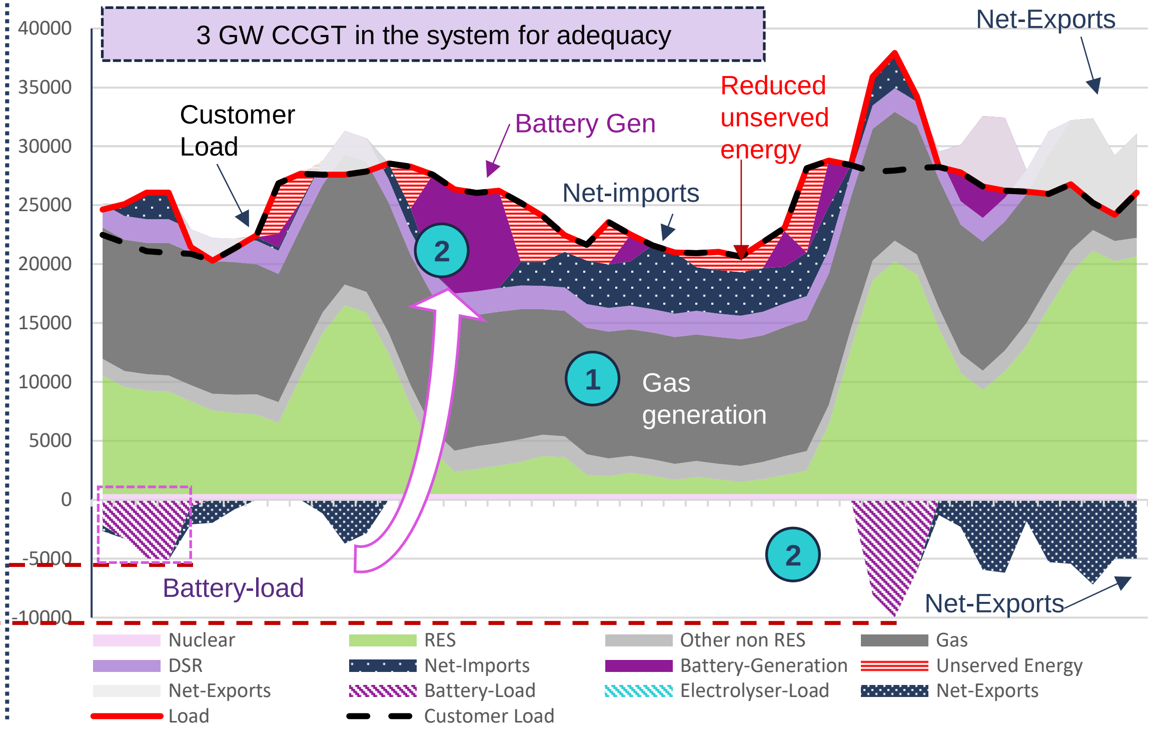
Note: *CL results are with an "average" outage pattern; CY1998 is not included in the graph as the LOLE = 0.*

This is because additional capacity under SR and CM have different impact on the charging patterns of batteries

Deviation SR: Hourly Dispatch – 10/11 January 2035 – CY1997 [MWh/h]



Market wide CM: Hourly Dispatch – 10/11 January 2035 – CY1997 [MWh/h]



Firm capacity generation not only increases overall electricity supply but also alters the charging and discharging patterns of batteries during peak hours:

1. The additional 3 GW of gas capacity in the system decreases the amount of unserved energy, and…
2. allows batteries to adjust their charging and discharging patterns (incl. peak hours), enabling them to contribute during periods of unserved energy.

During periods of system stress in the **Deviation scenario**, batteries are required to discharge over a shorter timeframe at higher capacity. In contrast, under the **Adequacy scenario**, they can spread their discharging more evenly across a longer duration.

The procurement cost of an SR or CM depends on several specific design choices, impacting the eligible volumes and contract prices

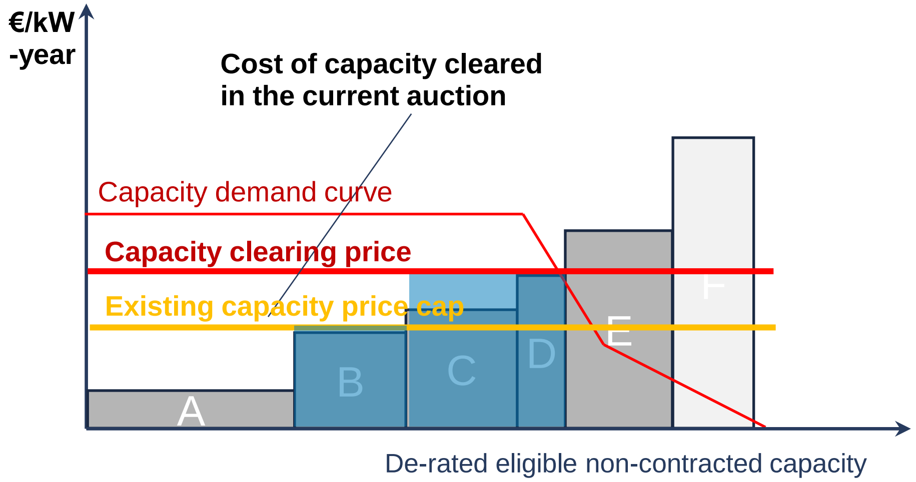
CM procurement cost

- Procurement cost of capacity cleared for the given delivery year at a clearing price. Given by the product of the cleared derated capacity and the clearing price
- The clearing price is given by the bid price of the last unit meeting the capacity demand
- The bids in the CM represent the "missing money", i.e. the fixed CAPEX and fixed operational and maintenance ("FOM") costs net of the expected market and AS net revenues.
- The volume of existing capacity that obtaining the clearing price depends on the eligibility rules of the CRM and may exclude capacity obtaining other support, e.g. RES and combined-heat and power ("CHP").
- Specific rules could be applied to limit the price obtained by the existing capacity below the clearing price

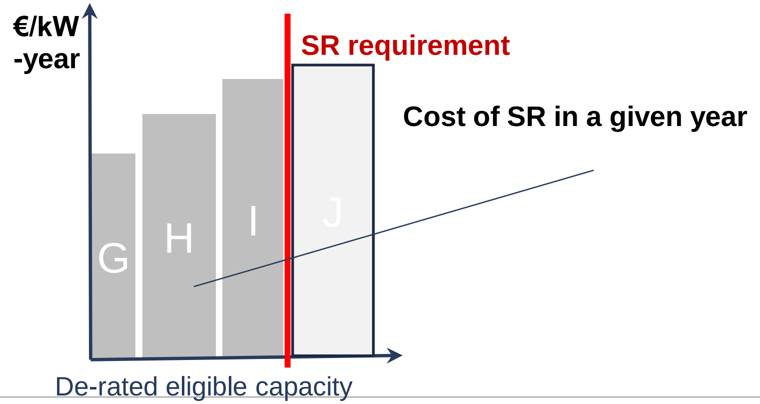
SR procurement cost

- The needed capacity is procured through a pay-as-bid auction and receives a one up to three-year contract.
- The bids correspond to the annualised fixed costs, assuming no operation in the market and that the activation cost is covered at the cost level.
- Procurement cost is equal to the product of the derated capacity and the bid price

CM cost in a given year

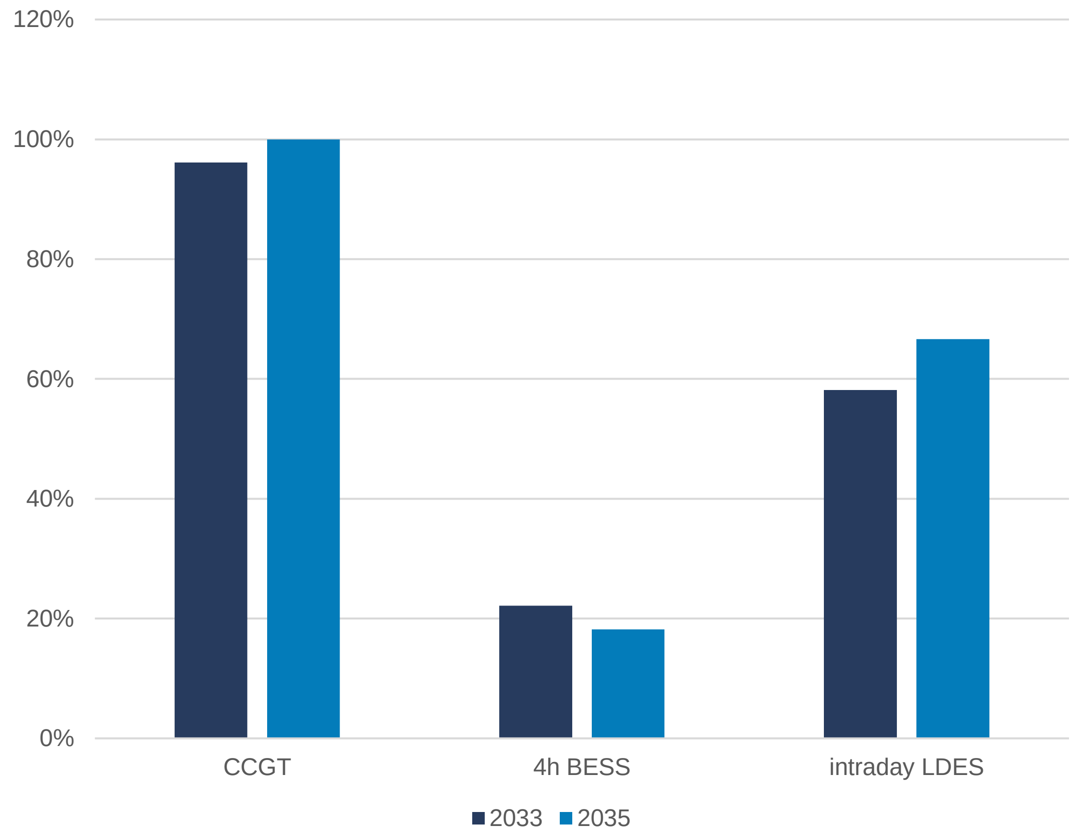


SR capacity cost in a given year



CCGTs present the highest derating factor among scrutinised technologies, while 4h BESS have a derating factor of c.20%

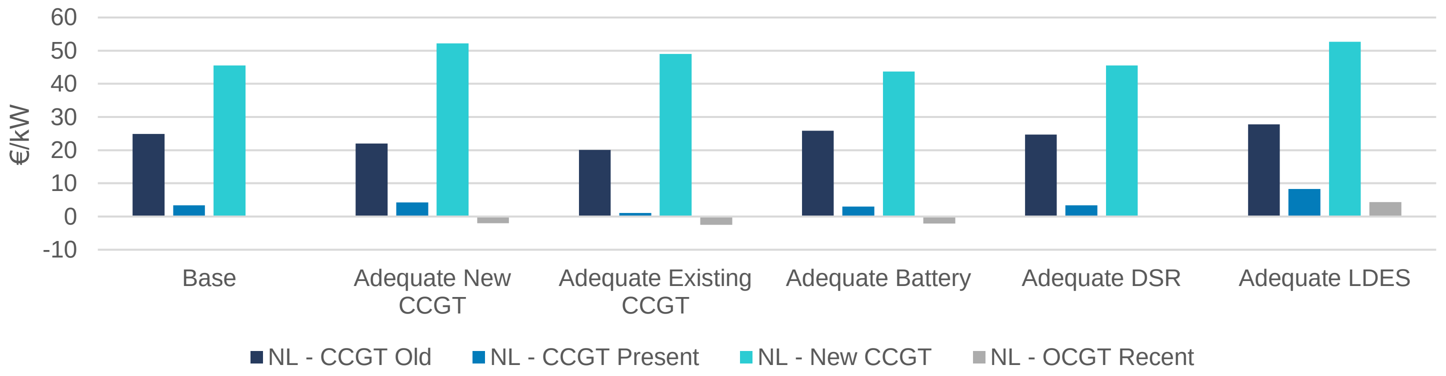
Derating factors per technology, 2033 and 2035 (in %)



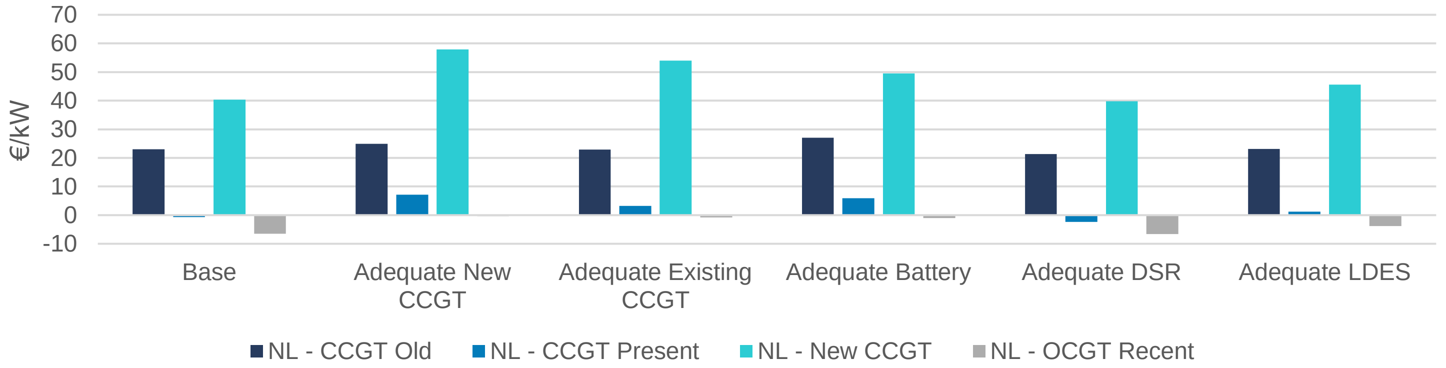
- Derating factors are estimated as the ratio of the additional capacity of each technology needed in the adequate scenarios over the additional DSR capacity in the adequate scenario DSR.
- Under such methodology, CCGT has a derating factor of 96% in 2033 and 100% in 2035, as the additional capacity is very similar or equal to the additional DSR capacity needed in the adequate scenario DSR.
- On the other end of the spectrum, 4h BESS present the lowest derating factor around 20%, as 11.7 GW and 16.5 GW in 2033 and 2035 respectively would be needed in the system to reach adequacy, compared to 2.5 GW and 3 GW of DSR.

As part of the economic viability analysis ("EVA"), we estimate CM prices to be around 30€/kW for existing assets and 50€/kW for new assets

Missing money for thermal technologies in 2033 in baseline and adequate scenarios (in €/kW)



Missing money for thermal technologies in 2035 in baseline and adequate scenarios (in €/kW)



Reading: *A positive missing money implies that the asset is not economically viable (cost larger than revenues), a negative missing money implies that the asset is profitable.*

To estimate the CM clearing price, we evaluated the missing money of existing and new thermal technologies in the Netherlands.

- To obtain results comparable with TenneT, we discarded the hours above 1120€/MWh which corresponds to the activation price of the second largest DSR band. The lower the threshold above which prices are discarded for the EVA, the higher the missing money.

In our base case scenario, Dutch thermal assets are not or barely viable in 2033 and 2035 without any CRM.

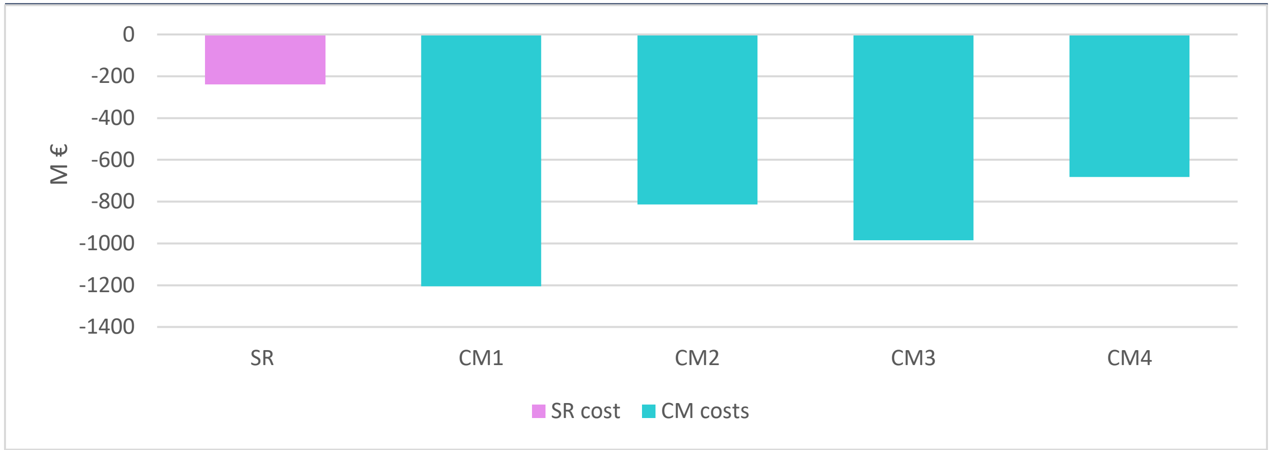
- As for existing assets, the **average missing money** of Old CCGT is **c. 25 €/kW** while the average missing money of Present CCGT (slightly higher efficiency) is close to 0 €/kW;
- As for new assets, the **average missing money** of New CCGT is **c. 50€/kW**.

Under the different adequate scenarios, we see that Old CCGT would set the CM price for existing assets around 25-30 €/kW, while new assets will set it on average at 50€/kW.

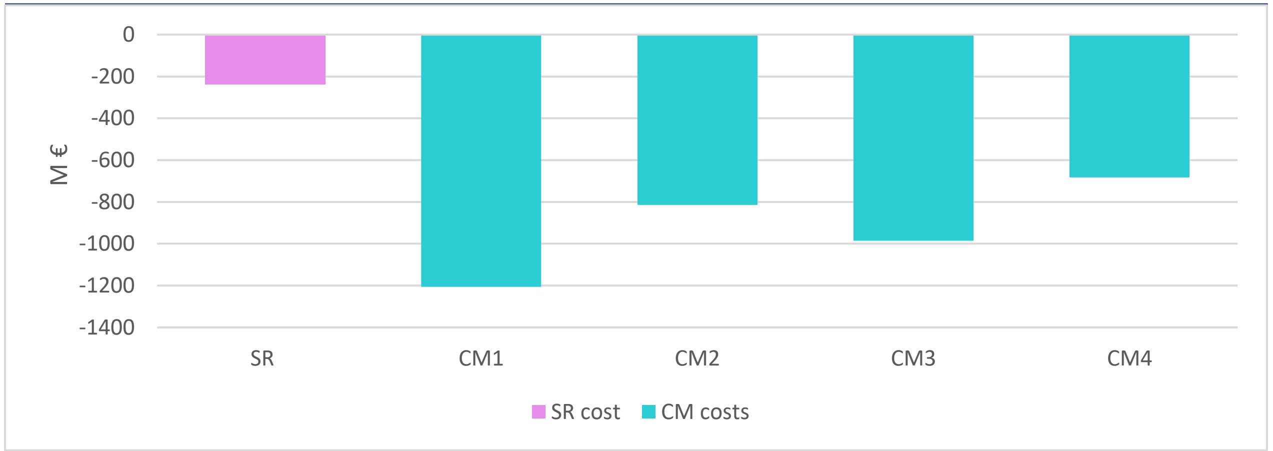
Note: *Missing money is calculated considering wholesale market revenues + a balancing market revenues estimated at 5€/kW. Hours with prices larger than 1120€/MWh are not considered. For existing thermal technologies, a FOM of 53€/kW is used as per MLZ25; for new technologies a CONE of 110€/kW is used, aligned on the values reported for CZ, IE and PL in ACER. Although there is new CCGT capacity only in the Adequate New CCGT scenario, its missing money in the other scenarios indicates its economics if there were new CCGT in those scenarios.*

Market-wide CM procurement costs vary depending on its design, but are generally higher than an SR procurement costs

Procurement costs for SR and CM scenarios in 2033



Procurement costs for SR and CRM scenarios in 2035



- **SR** is assumed to be **mostly existing gas capacity** (5.5 GW of retired capacity between 2023 and 2033 in MLZ25) and DSR.
- We consider **4 CM implementations**:
  - **One eligibility scope including RES and another excluding RES;**
  - **unique price** and **separate prices** for existing and new build.
- Based on our EVA, the **unique price** is set at **50€/kW** and the separate **existing capacity price** is set as **30€/kW**.

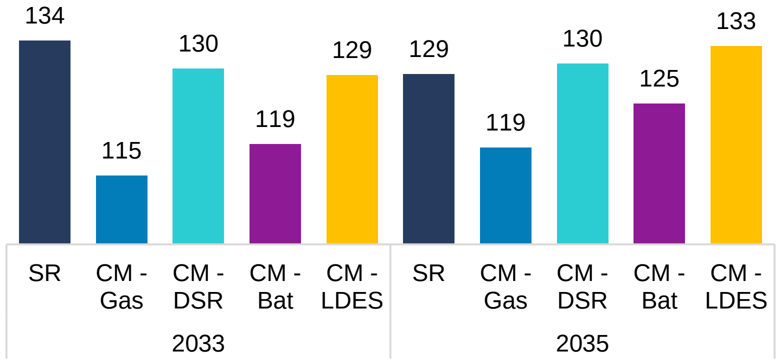
CM scenario	Eligibility	Price
CM1	All	Unique price
CM2	All	Separate prices
CM3	Excl. RES	Unique price
CM4	Excl. RES	Separate prices

- **CM procurement costs are higher than SR procurement costs** as it covers a wider range of capacity
- A unique price CRM design could have higher costs than a CM with separate prices for existing and new capacity.

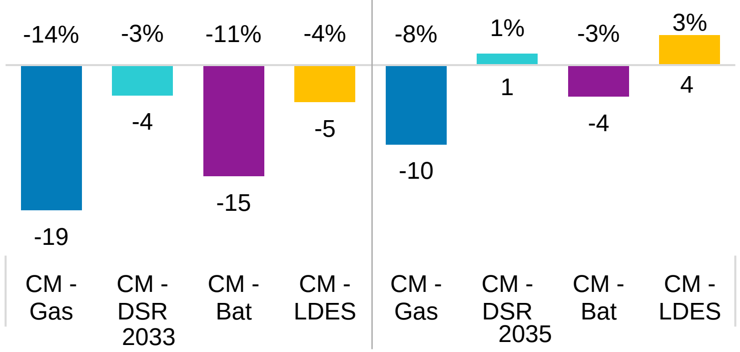
***Note:** CL results are with an "average" outage pattern. The estimated procurement costs are in line with observed procurement costs across Europe (corrected for the size of the Netherlands), see Figure 15 of the SoS 2024 monitoring report from ACER (link).*

A market-wide CM allows in general to reduce average baseload prices and price volatility compared to the SR scenario

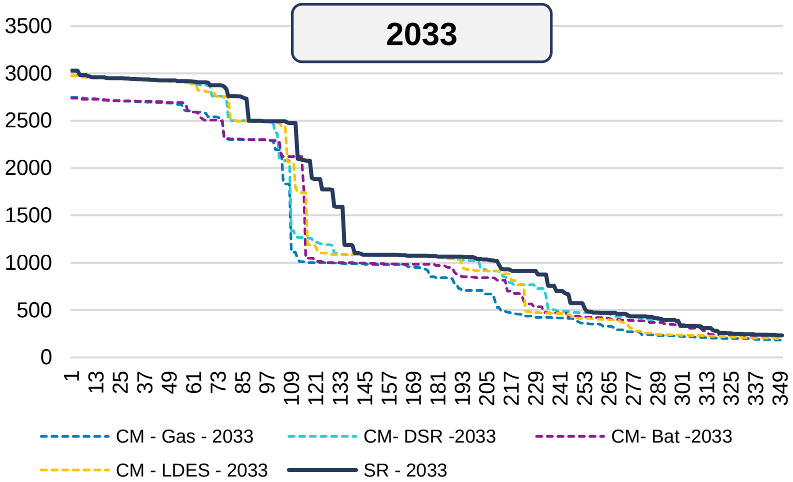
Baseload electricity prices (€/MWh)

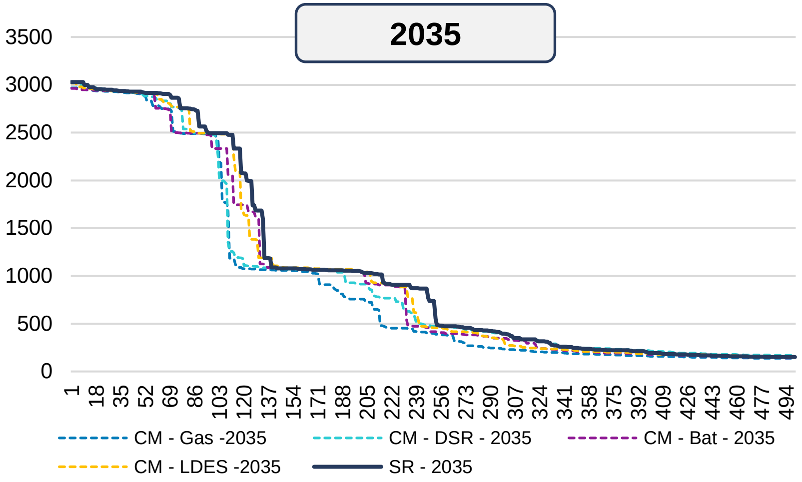


Price difference in CM vs SR (% and €/MWh)



350 hours with highest electricity prices – CM vs. SR





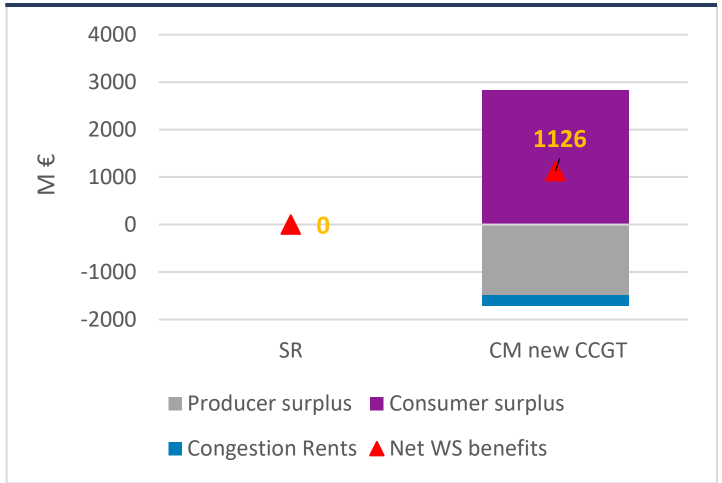
- The capacity mix in the CM scenarios leads to in general lower wholesale prices compared to the SR scenario with an average price decrease of 6 €/MWh and 5% across 2033 & 2035.
- The price decrease is the highest in the adequate scenario CCGT.
- The difference in annual power prices between SR and CM scenarios is due to more frequent extreme prices in the SR scenario, given that the capacity under SR is kept outside of the market and cannot impact the market price.
- This leads to a lower standard deviation of the wholesale price under a CM bringing additional benefits such as lower risk premia for retailers.

Electricity price Std	SR	CM - Gas
Mean	562	487
Min	237	244
Max	708	632

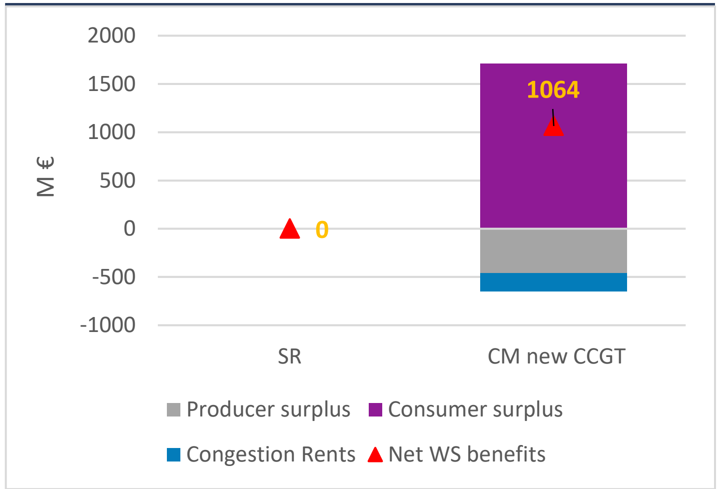
Note: Electricity prices for a weighted average of the CY 1997, 1998 and 2013. The standard deviation was computed for the hourly price times series of each target year and climate year. Here gas scenario is with new CCGT. Std = standard deviation.

Unlike the SR, a CM could lower energy prices and create net WS welfare benefits in addition to SoS welfare benefits

Wholesale market benefits in 2033

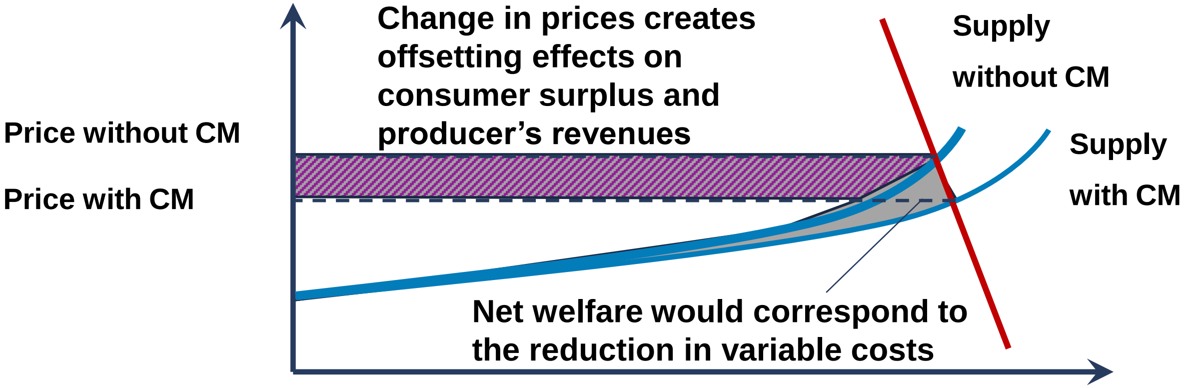


Wholesale market benefits in 2035



- As SR is designed not to be activated within the wholesale market, it **would not change the wholesale prices.**
- In contrast, additional capacity procured by a CM would operate in the market and could decrease wholesale prices, resulting in higher consumer surplus and lower producer profits and congestion rents.
- Assuming the CM allows procuring new CCGT capacity, this could result in **net social benefit realised in the wholesale market of ~1.1B€ per yea**r.

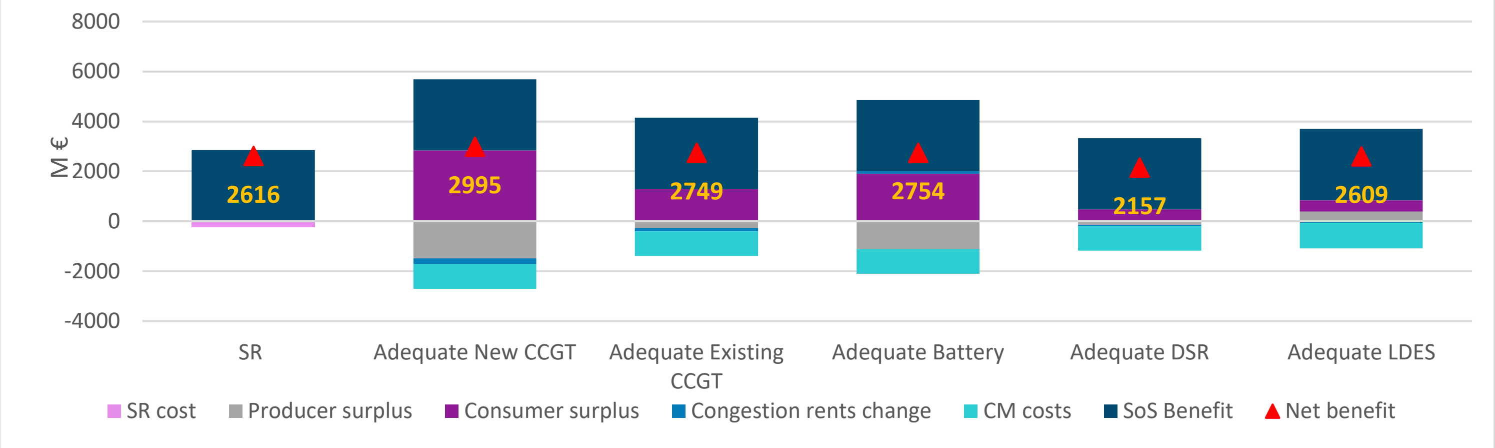
Net benefit corresponds to the decrease in variable cost



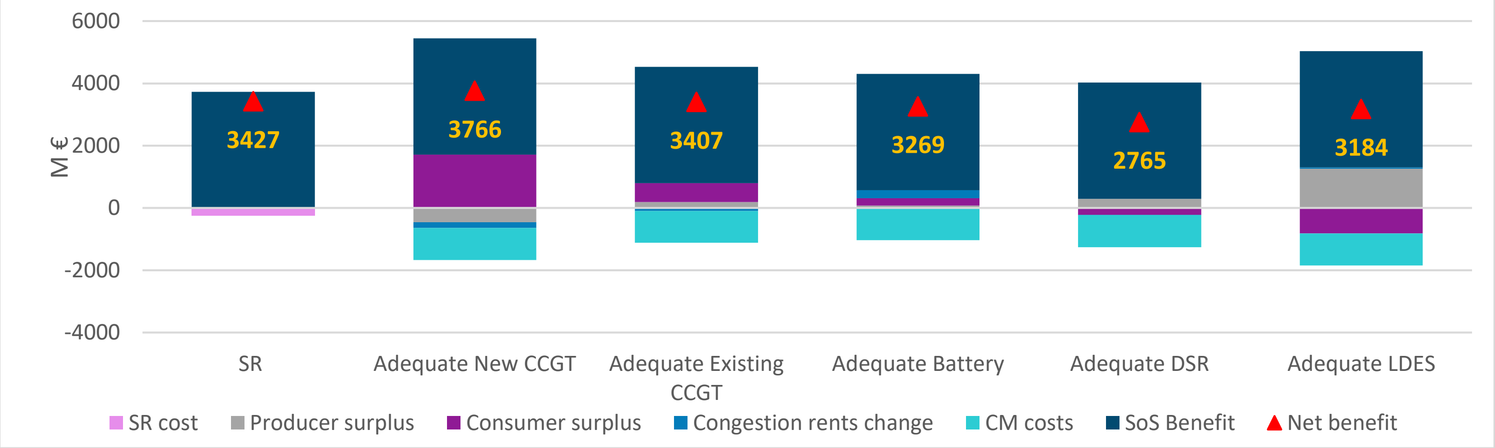
Note: *CL results are with an "average" outage pattern.*

Baseline assessment: The net benefit of an SR lies within the benefit range of CM scenarios with different technologies

Cost benefit analysis (in M€/year) for SR and CM scenarios in 2033 – CM3 implementation



Cost benefit analysis (in M€/year) for SR and CM scenarios in 2035 – CM3 implementation

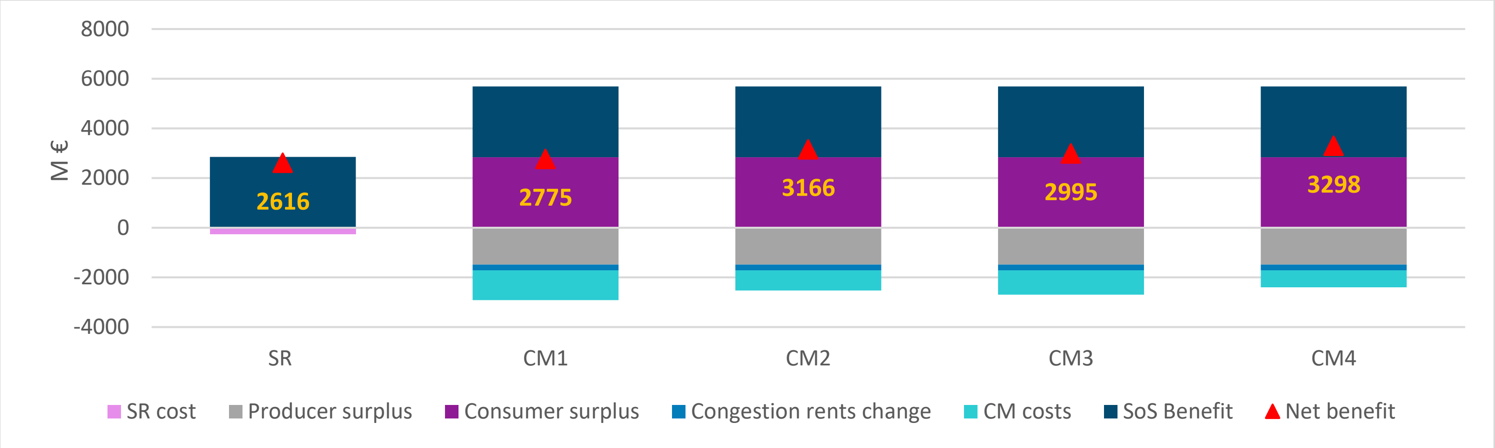


- Our CBA reveals a **positive net benefit both in the SR and CM scenarios**, driven mainly by the large SoS benefits due to a VOLL at 69k€/MWh.
- Considering a CM implementation (CM3) with a unique price at 50€/MWh while excluding renewables, the net benefit ranges between 2.2 and 3 B€ per year in 2033 and 2.8 to 3.8 B€ per year in 2035 **with the net benefit of an SR lying within the net benefit range of the different CM scenarios**.
- The differences in net benefit across the CM scenarios reflect the varying degrees of system variable cost reductions per adequate scenario (representing different technologies being procured in the CM).
- The new CCGT scenario is the most efficient to drive down system variable costs and has the highest net benefit while the DSR scenario is less efficient to its higher variable cost.

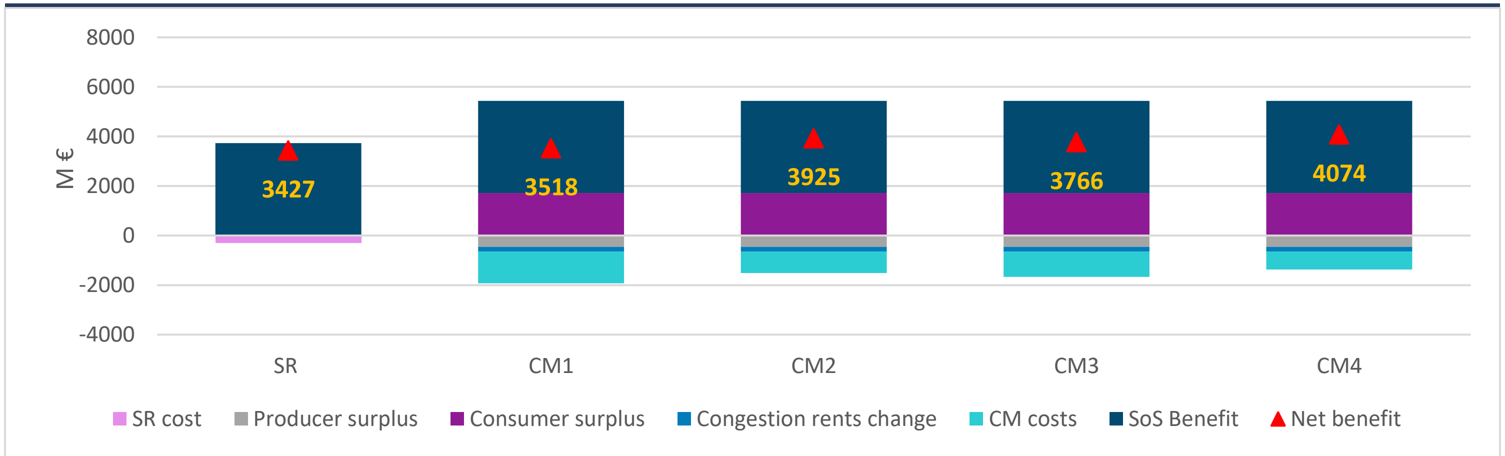
Note: CL results are with an "average" outage pattern. Here we show the results for the CM3 implementation (excluding RES and a unique clearing price), the results for other implementations under the "Adequate New CCGT" CM scenario are shown in the next slide.

<u>Baseline assessment</u>: A CM procuring new CCGTs has higher net welfare benefits than an SR under all four CM implementations

Cost benefit analysis (in M€/year) for SR and CM implementation in 2033



Cost benefit analysis (in M€/year) for SR and CM implementation in 2035



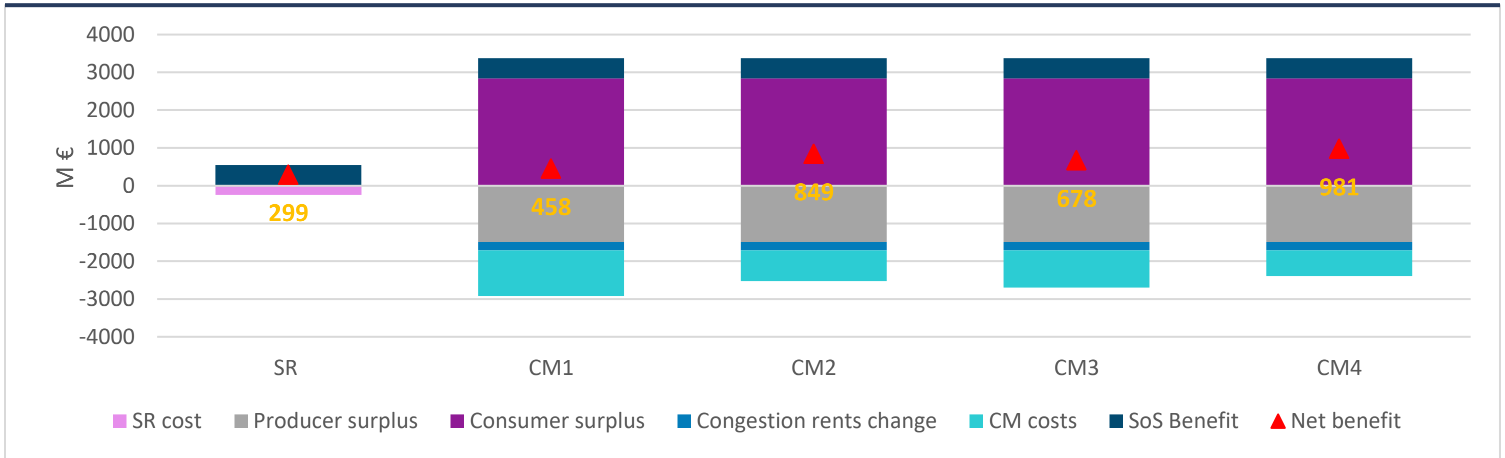
- The CBA reveals a **positive net benefit both** in an SR and the CM implementations, driven mainly by the very large SoS benefits due to a VOLL at 69k€/MWh.
- The net benefit ranges between 2.6 and 3.2 B€ per year in 2033, and 3.4 and 4.1 B€ per year in 2035.

	Eligibility	Price
CM1	All	Unique price
CM2	All	Separate prices
CM3	Excl. RES	Unique price
CM4	Excl. RES	Separate prices

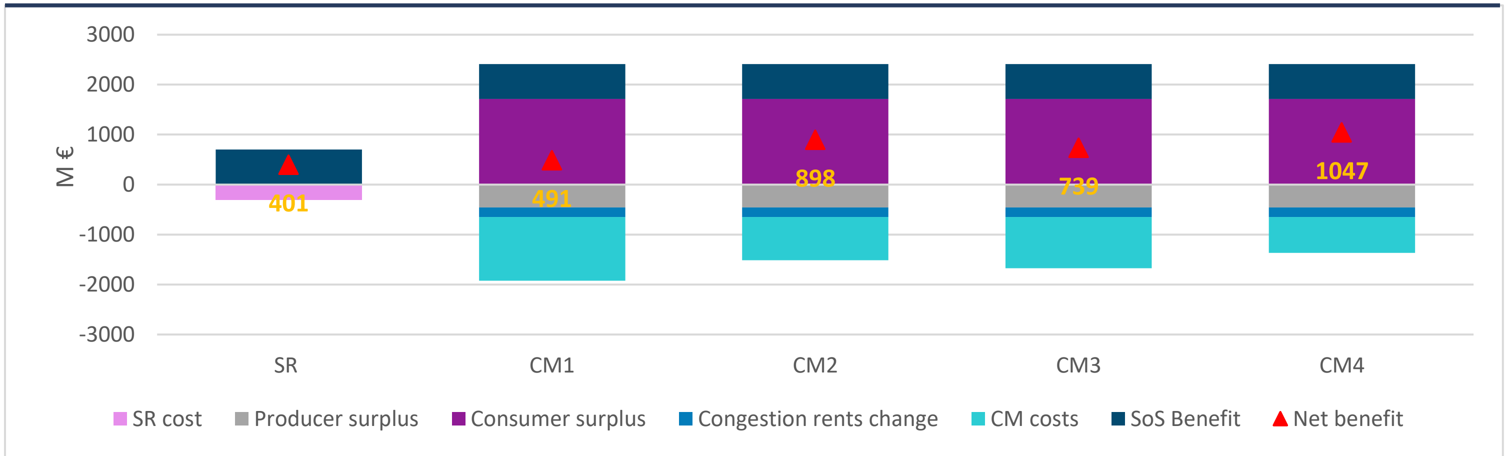
Note: *CL results are with an "average" outage pattern.*

Sensitivity assessment: the net benefit of an SR or CM could be lower in case the Dutch VOLL was revised at the level close to Belgian VOLL

Cost benefit analysis (in M€/year) for SR and CM implementations in 2033 - VOLL at 13k€/MWh



Cost benefit analysis (in M€/year) for SR and CM implementations in 2035 - VOLL at 13k€/MWh



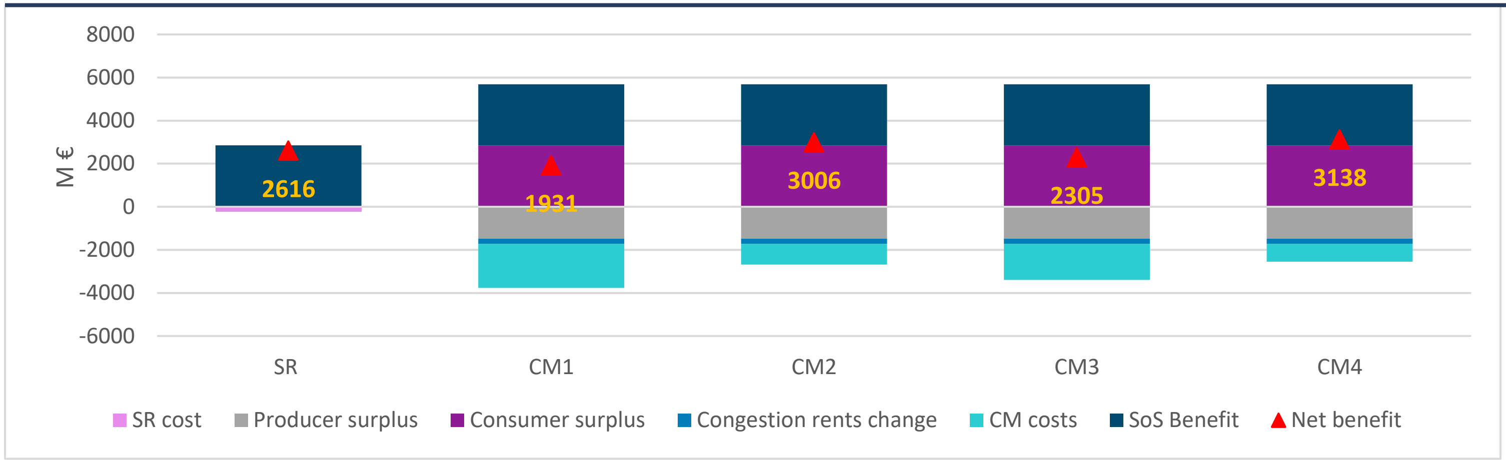
- As the previous results are mainly driven by the high VOLL that the Netherlands have, here we conduct a sensitivity analysis by using the Belgian VOLL of 13k€/MWh.
- The overall net benefits could be **much lower** if the Dutch VOLL was revised to the level of Belgian VOLL.
- Importantly also with a much lower VOLL the **welfare benefits of an intervention remain positive**.

	Eligibility	Price
CM1	All	Unique price
CM2	All	Separate prices
CM3	Excl. RES	Unique price
CM4	Excl. RES	Separate prices

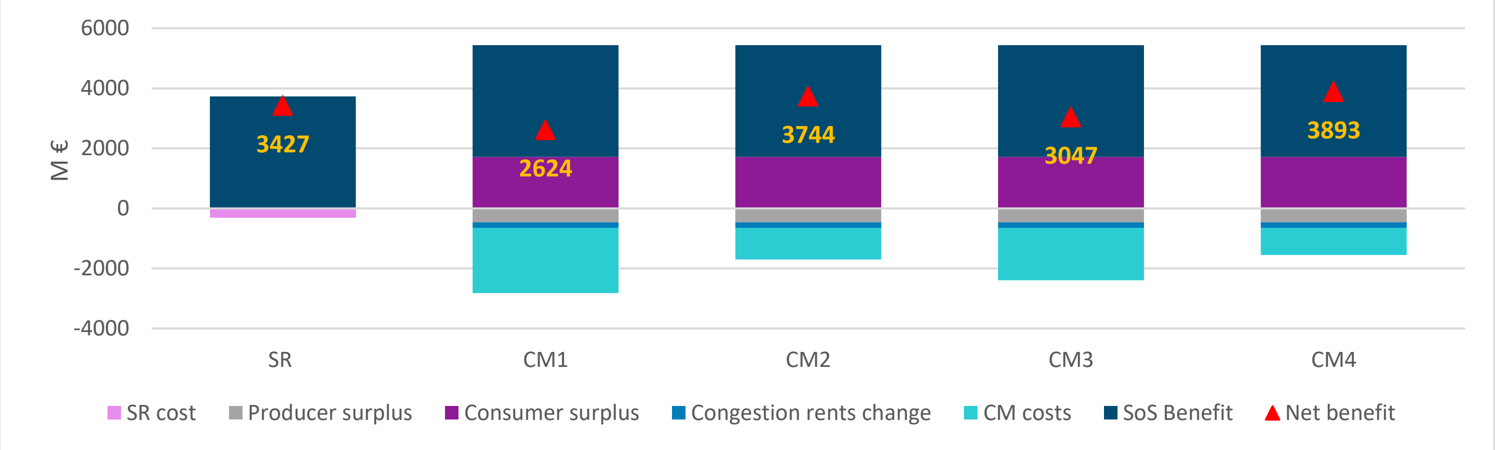
Note: *CL results are with an "average" outage pattern. Here we show the results for the scenario CM new CCGTs, similar conclusions can be reached .*

Sensitivity assessment: The net benefit of an SR remains within the CM benefit range when assuming a higher clearing price for the CM

Cost benefit analysis (in M€/year) for SR and CM implementations in 2033 – unique price at 85€/kW



Cost benefit analysis (in M€/year) for SR and CM implementations in 2035 – unique price at 85€/kW



- Our EVA estimates the unique CM price to be at 50€/kW and the CM price for existing capacity at 30€/kW.
- However, **if we would assume the unique clearing price would raise to 85 €/kW** (e.g. due to supply chain disruptions), the net benefit would be lower, ranging between 1.9 and 3.1 B€ per year in 2033, and 2.6 and 3.9 B€ per year in 2035.
- Under this assumption, the net benefit of the CM implementations with a unique clearing price (CM1 and CM3) is lower than that of an SR but the net benefit of the CM implementations with separate prices (CM2 and CM4) remains higher than that of an SR.

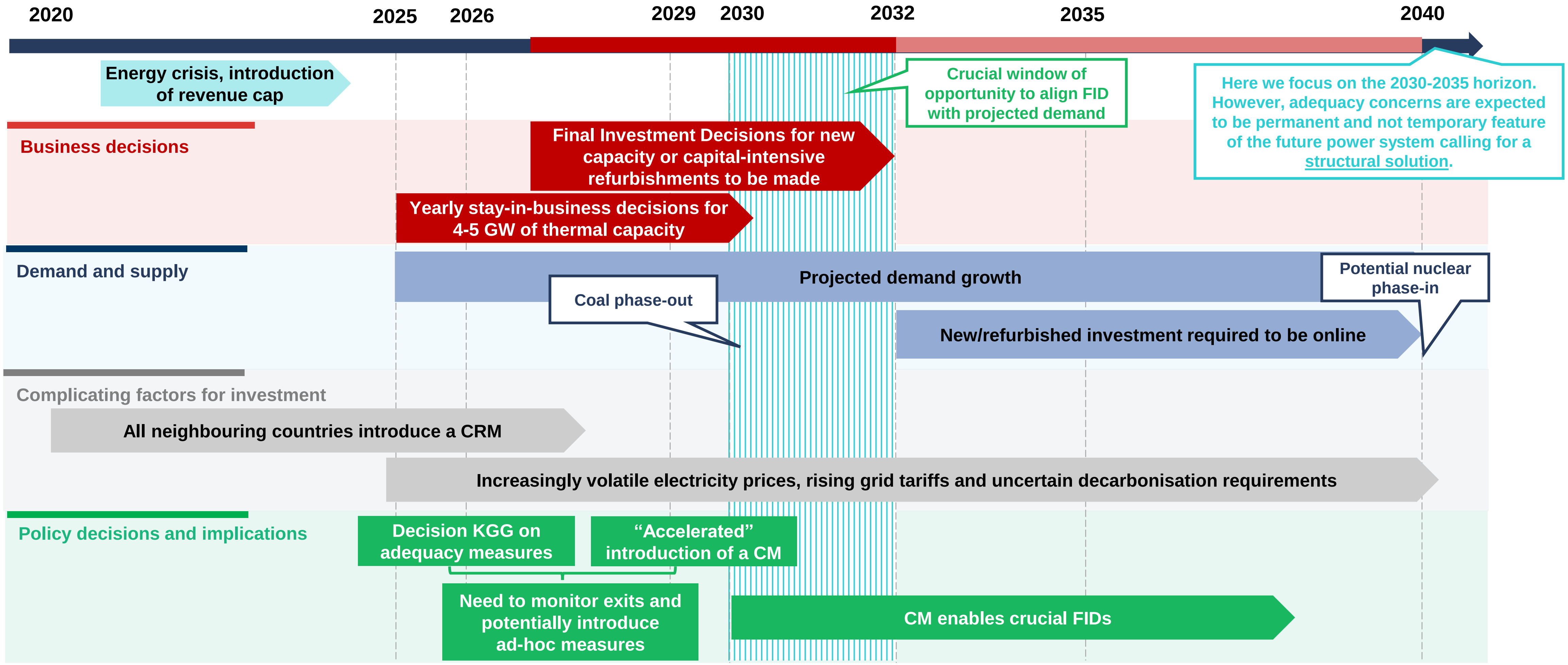
	Eligibility	Price
CM1	All	Unique price
CM2	All	Separate prices
CM3	Excl. RES	Unique price
CM4	Excl. RES	Separate prices

Note: *CL results are with an "average" outage pattern. Here we show the results for the scenario CM new CCGTs.*

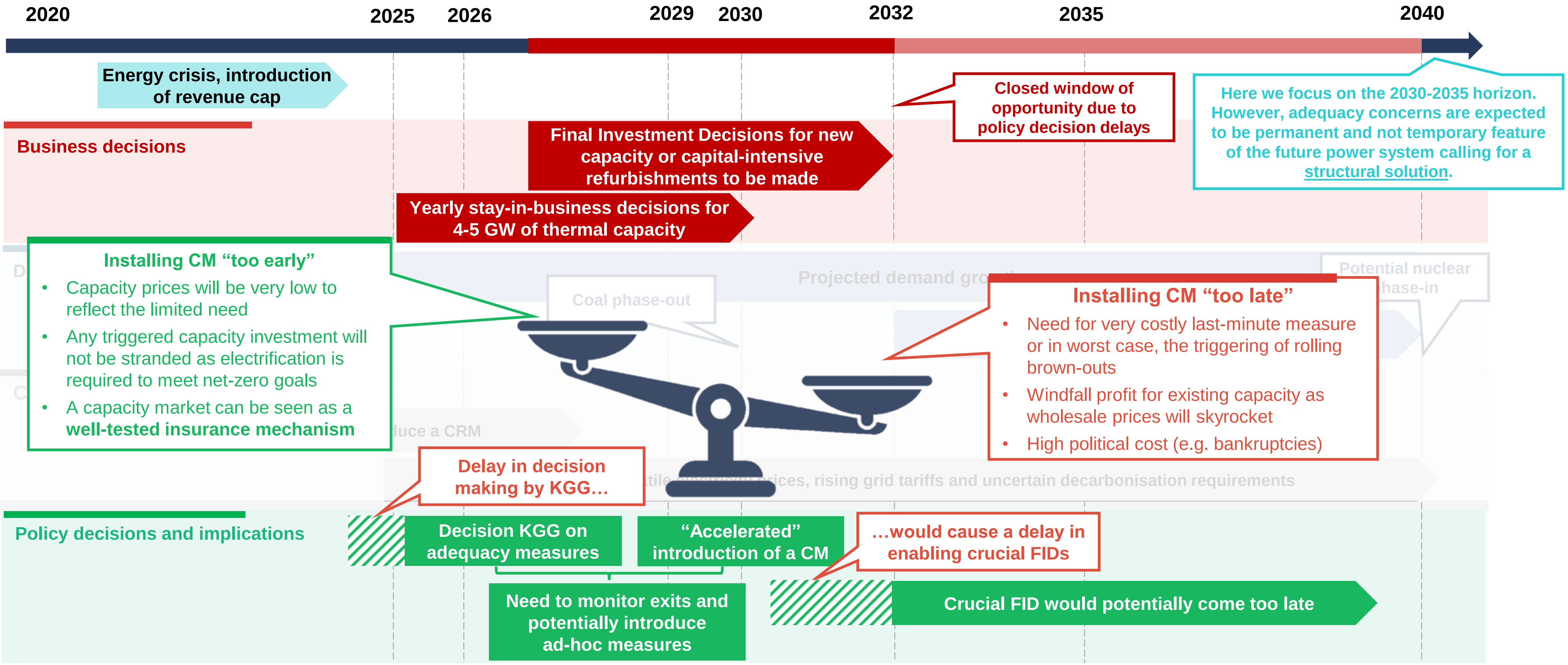
3.5

Recommendation and phase-in solutions

Considering the strong risk of adequacy concerns and welfare benefits of an intervention, we recommend the introduction of a CM…



… without delay as the costs for being too early are much lower than being too late



5.

Appendix - CRM approach in neighbouring and other selected countries

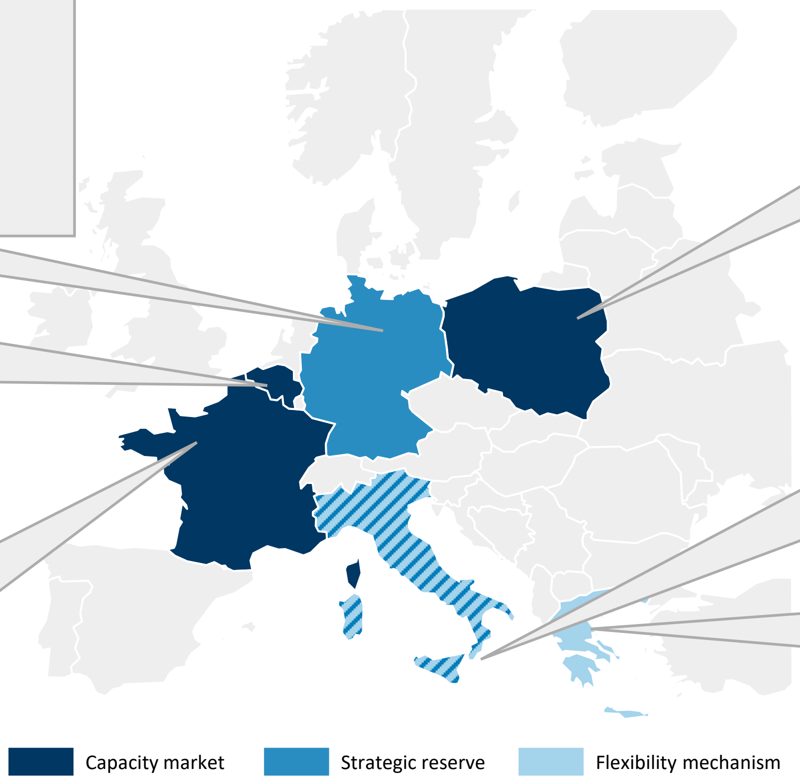
5.1
Overview

Overview of selected country case studies

Strategic reserve
- Introduced in winter 2020/2021
- Bi-annual tenders held by TSOs
- Payments financed via grid tariffs
- Capacity mechanism targeted by new government in 2028.
- Uncertainty around additional procurement mechanism

Centralised capacity market
- First auction in 2021
- Reliability options
- Up to 15 yrs contracts
- Intermediate Price Cap for existing capacity
- Specific provisions (Y-1 auction, payback exemption) to incentivize DSR

Transition from decentralised to centralised capacity mechanism
- Introduced in 2017
- Currently decentralised, with Availability Obligation
- Up to 7 yrs contracts
- Specific call for tender for DSR to complement CRM revenues
- New centralised mechanism being implemented



Centralised capacity market
- Competitive auctions since 2018
- Price caps for auction set by TSO
- Up to 15 yrs contracts
- Availability obligation in relation to actual need in the system

Centralised capacity market
- Introduced in 2019
- Reliability options
- Intermediate Price Cap for existing capacity
- Up to 15 yrs contracts

Flexibility scheme
- Technology-specific auctions since 2023
- Residual capacity participating in ancillary and balancing markets

Flexibility scheme
- Transitory scheme in 2019, storage-specific scheme since 2022
- Competitive tenders held by regulator
- Full integration in all electricity markets
- Support provided as investment grant and Contract-for-Difference ("CfD")

5.2

Belgium

The CM aims to foster investment and guarantee Belgium’s system adequacy, by covering the missing money of existing and new capacities

A centralised market-wide CRM has been introduced to ensure security of supply in Belgium

- In connection with the nuclear phase-out legislation and with a view to maintaining the required level of security of supply for Belgium, the Belgian authorities introduced the CRM, which is enshrined in the Electricity Act and forms the legal basis.
- The CRM aims to compensate electrical capacity holders for that portion of their relevant costs that are not covered by their revenues (‘missing money’): **it ensures the profitability of capacities so that capacity holders maintain their capacity in the market or invest in new capacities.**

Capacity auctions are held regularly, for different timeframes and contract lengths

- In the initial design, for each year of delivery, two capacity auctions were held, 4 years and 1 year before delivery. However, from 2025, auctions are also held 2 years before delivery.
- Capacity auctions are cleared with a **pay-as-bid approach.**
- The duration of the availability obligation is 1 year for existing capacities, with activations during periods of price peak, and availability tests.
- Capacity units with investment costs above certain thresholds (respectively 106/239/360 €/kW) are eligible to multi-year capacity contracts (respectively 3/8/15 years)

Key features of the Belgian CRM

1 Centralised	Elia is responsible for operating the auctions, calculating administered demand
2 Market-wide w/ eligibility	All eligible capacities can participate to the competitive bidding procedure, production and demand-side units with derated capacity >1MW are legally bound to prequalify
3 Technology neutral	All technologies without on-going operating subsidies are allowed to participate in the CRM. However, they are subject to the application of a derating factor representing the degree to which the technology enhances security of supply, and prequalification is mandatory
4 Reliability Option	Profits derived from energy market in scarcity periods above a certain threshold (strike price) will have to be paid back
5 Long-term contracts	Depending on investment thresholds, participating capacities could secure long-term contract (up to 15 years) subject to CREG’s approval
6 Penalties	Penalties are applicable if the commissioning is delayed Planned and unplanned unavailability, proven through Elia’s controls, is subject to penalties

***Notes**: All € figures are expressed in real 2023 unless otherwise stated*

The Belgium CM includes a reliability option associated with scarcity revenue pay-back obligations

The law defines a "reliability options" scheme

- It consists in a limitation of profits derived from energy market in scarcity periods, above a certain threshold (strike price)
- When the market price used as reference indicator exceeds the threshold, the capacity provider pays back a part of the monthly premium.

Determination of the reference market price:

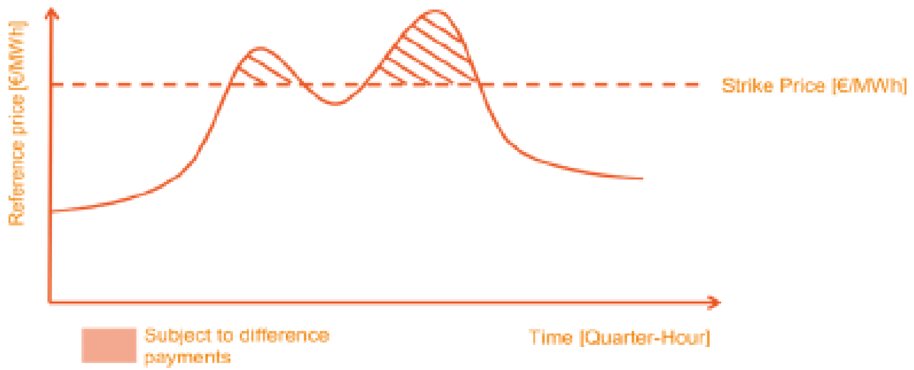
- The DAM price will be used by Elia as it is relevant to captures tense situations

Determination of the strike price:

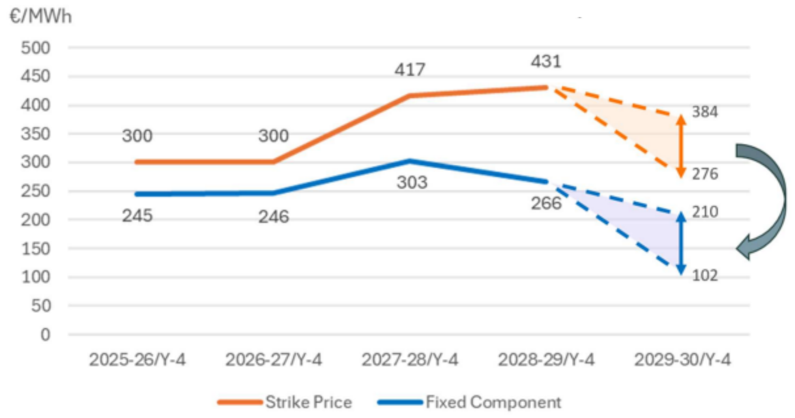
- Since the EC approved the changes to the Belgian capacity mechanism in September 2023, the strike price is composed of a fixed component and a variable component:
- The fixed component is determined at the time of the auction and consists of the calibrated strike price minus the average DA prices for the calibration period:
  - The calibrated strike price is calculated from a study of elastic reaction volumes in relation to spot prices served as basis for determining the initial strike price window.
  - From this calibrated strike price, Elia withdraws the average of the DA prices for the calibrated period
- The variable component is composed of the average DA monthly price for every month of the delivery period.

If the spot price is higher than the strike price and if the asset is activated in the market, the Capacity Provider reimburses the delta for its contracted capacity. However, if a unit is in announced forced outage, it is not liable to the pay-back obligation (but be subject to availability penalty). For payback obligation, a penalty cap is expected: annual payback obligation cannot exceed the yearly contract value.

Reliability options principle



Evolution of Strike Price and Fixed Component



Sources: Elia (2025), Fgov.Be, Calibration report, Elia (2023), CRM Product Sheet

Existing capacities are subject to an Intermediate Price Cap and contracts can exceed one-year delivery period based on investment thresholds

The standard duration of contracts is 1 year. Upon the Belgian regulator's (CREG) derogation, based on high investment criteria, capacity contracts of max 3, 8 and 15 years can be granted through the "Investment files"

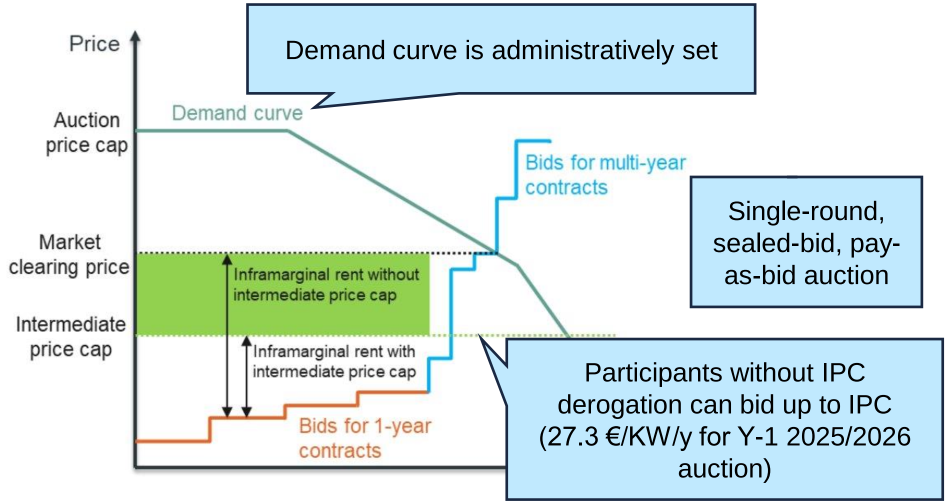
	One-year contract*	Multi-year contract
New capacities	▪ Participants can bid up to Intermediate Price Cap ("IPC"). ▪ It is possible to request an IPC derogation to CREG	▪ 3, 8 or 15 years ▪ To be eligible, participants must respect CAPEX thresholds
Existing capacities		▪ 3 or 8 years ▪ To be eligible, participants must respect CAPEX thresholds ▪ Participants can bid up to Intermediate Price Cap ("IPC"). ▪ It is possible to request an IPC derogation to CREG

Participants	Contract duration	CAPEX threshold (€/kW)
New capacities	15y	360
	8y	239
	3y	106
Existing capacities	3y or 8y	30

The maximum IPC is set for each auction by a study assessing the highest missing money level among existing plants (in €/MW/y).

- IPC derogation requests (or "investment files") must include detailed costs, revenues and missing money estimates.
- CREG accepts derogation if **missing money estimates > auction IPC.**

Price formation in the auction



***Notes**:* In practice, only existing capacities participate in 1-y contract and are subject to IPC.*
Source: Arrêté royal fixant les seuils d'investissements, les critères d'éligibilité des coûts d'investissement et la procédure de classement, Elia (2025)

Some arrangements have been introduced for DSR, and the attractiveness of the CM for DSR will be assessed in forthcoming Y-1 auctions

Specific rules applicable to DSR participations

Choice of de-rating / SLA

DSR operators allowed to tailor their obligation to some technical constraints

- DSR operators can chose a **service level agreement** (SLA), i.e. an **availability duration obligation** (1h to unlimited) in line with their technical constraints.
- The obligated capacity equals their non-de-rated capacity for hours within their energy constraints, and to zero for any other hour in the same day.

Specific rules applicable to DSR participation

- Criticism has been voiced by DSR players regarding the applicability of reliability options to DSR assets. Since 2024, **DSR is exempt from the payback obligation**, and from 2025, the exemption will apply to DSR and storage.
- For the **2024 auctions, DSR capacity was awarded contracts**:
  - Y-4 auction: 246 MW of existing capacity, mostly with SLA unlimited (all submitted bids were awarded a contract)
  - Y-1 auction: 11 MW (1 MW of SLA 12h, and 10 MW of existing capacity with SLA unlimited) – among 18 MW of submitted bids
- **The behaviour of players in the forthcoming DY-2 and DY-1 auctions, whose timing in relation to delivery is supposed to be more appropriate than for DY-4, will nevertheless give a clearer indication of the attractiveness of the CRM for DSR capacity**

SLA choice for DSR participations, for Y-1, Y-2 et Y-4 auctions

Catégorie I : Catégories d'accords de niveau de service (SLA)	
Sous-catégories	Facteur de réduction [%]
SLA-1h	21 (2026) / 19 (2027) / 16 (2029)
SLA-2h	36 (2026) / 34 (2027) / 29 (2029)
SLA-3h	49 (2026) / 47 (2027) / 40 (2029)
SLA-4h	58 (2026) / 56 (2027) / 49 (2029)
SLA-5h	65 (2026) / 65 (2027) / 56 (2029)
SLA-6h	72 (2026) / 72 (2027) / 63 (2029)
SLA-7h	76 (2026) / 77 (2027) / 69 (2029)
SLA-8h	81 (2026) / 82 (2027) / 74 (2029)
SLA-9h	85 (2026) / 87 (2027) / 79 (2029)
SLA-10h	88 (2026) / 90 (2027) / 83 (2029)
SLA-11h	92 (2026) / 94 (2027) / 86 (2029)
SLA-12h	94 (2026) / 96 (2027) / 89 (2029)
SLA illimité	100 (2026) / 100 (2027) /100 (2029)

*__Sources__ : Commission Decision of 27.8.2021 on State aid SA.54915 - 2020/C (ex 2019/N) : Belgium - Capacity remuneration mechanism ; [1] Elia (2021) Elia fiche produit – Mécanisme de remuneration de capacité [2] Elia (2022) Elia product sheet – Capacity remuneration Mechanism ; Status CRM Design, RTE (2021) Retour d'expérience sur le mécanisme de capacité français, Elia (2025) CRM, Elia (2024) CRM auctions results __Notes__: *AMT: Availability Monitoring Trigger – Moments during which the day-ahead market price exceeds a given threshold. All € figures are expressed in real 2023 unless otherwise stated*

The weighted average price for existing capacity can be substantially lower than the highest accepted bid from new capacity

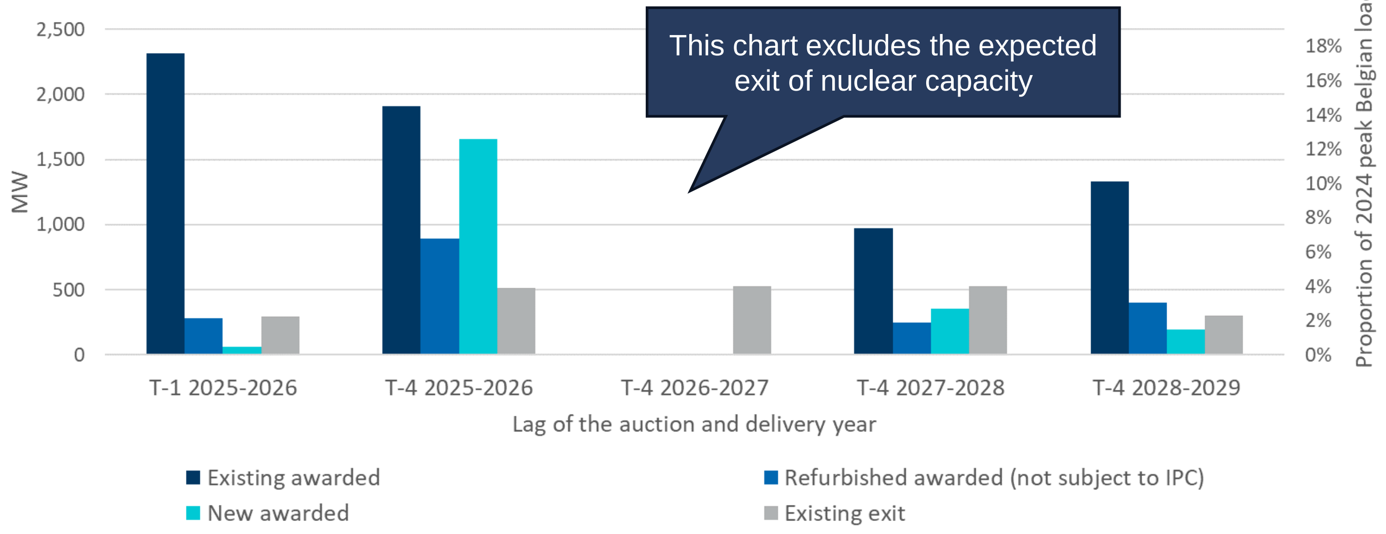
Capacity prices and price cap parameters for the Belgian capacity auctions[1]

1. Due to the pay-as-bid nature of the auctions, the weighted average price of all accepted bids (first column) can be substantially lower than the most expensive accepted bid (last column).
2. Due to the price cap for existing capacity (IPC), the weighted average price for awarded existing capacity (second column) can be substantially lower than the weighted price of awarded new capacity (third column).
3. Due to the different timing of the auctions for the same delivery year, the capacity price for the same delivery year can be substantially different (Y-1 2025-2026 vs Y-4 2025-2026 auction results above).

Note: (1) Based on data published by Elia (link).

Belgium was able to attract a significant volume of new capacity via its CRM, however as well significant volumes of existing capacity exited

Awarded volumes and exiting of existing units in the Belgian capacity auctions[1,2]



Duration of contracts awarded in the four Y-4 auctions

Contract duration	2025/26	2026/27	2027/28	2028/29
1-year	62.8%	-	61.8%	89.5%
3-year	-	-	15.6%	-
8-year	-	-	-	-
15-year	37.2%	-	22.7%	10.5%

New gas-fired units and batteries won nearly all the 15-year contracts

1. Significant volumes of new and refurbished capacity have been awarded in the capacity mechanism (total of > 3.5 GW), especially in the first T-4 auction.
2. However, each auction between 300-530 MW of existing capacity opted out and retired. For each of those auctions, the weighted average bid price of the awarded “additional” capacity was substantially higher than the weighted average bid price of awarded existing capacity.
3. Most new capacity has been awarded a 15-year contract.

Note: (1) Based on data published by Elia (link); (2) According to data from the ENTSO-E the Belgian peak load in 2024 was 13,282 MW.

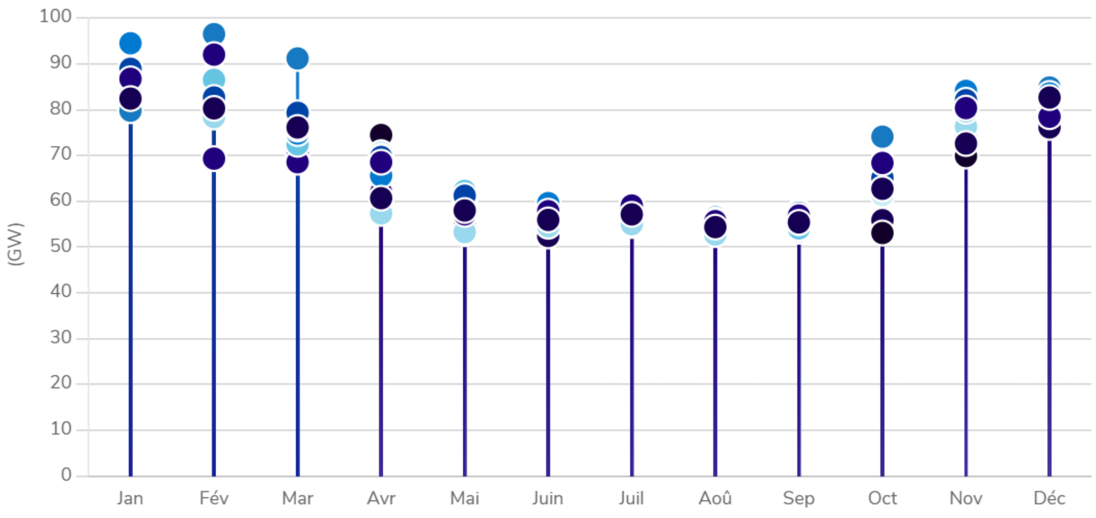
5.3
France

The French CRM was introduced in 2010 by law, to reinforce security of supply and ensure adequacy, and approved by the EC in 2016

Context: the CRM was introduced in a context of increasing peak demand

- The implementation of a capacity mechanism in France was **introduced by law in 2010**. It aims at reinforcing security of supply and ensuring adequacy between generation and consumption, especially during peak consumption periods, in order to meet the targeted reliability criteria. The French CRM was **approved by the European Commission in** 2016 as State aid compliant and became **officially operational from January 1, 2017**.
- The CRM was introduced in a context of increasing peak demand – particularly **sensitive to weather conditions** due to the high share of **electric heating in France**. Indeed, the historical peak in 2001 was of 79.6GW, while it reached 102.1GW in 2012. This led to **increasing risks for security of supply in France**.
- The implementation of a CRM was deemed necessary because, in the absence of CRM, not all the required capacity to meet peak demand would **get sufficient revenues** in the energy market to be economically viable. For instance, some of the thermal plants – especially peaking units – would be used mainly to cover **demand at peak** and would therefore benefit from energy market revenues during a very limited time.
- As a result, the **rare occurrences of these cold spells and the associated high consumption peaks can make it economically unviable to maintain existing capacity or to invest in new electricity generation capacity to a level adequate to secure electricity supplies in such periods**.

Peak demand in France, 2014-2024

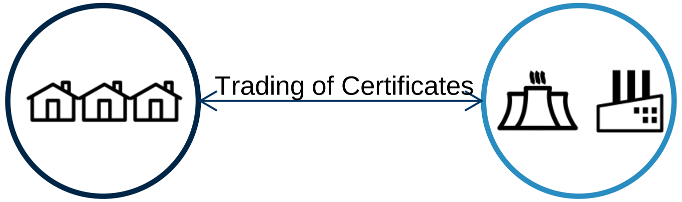


Sources : RTE

The French CRM: a decentralised market-wide capacity mechanism

The French CRM creates a market between suppliers and capacity holders:

- Electricity suppliers and network operators **must hold capacity guarantees** to cover the normalized [1] peak consumption of their customers and loss on a given "**PP1**" reference period [2] for each individual year, and are subject to penalties if they do not.
- French and foreign capacity holders (generators, DR operators) are granted guarantees by RTE on the basis of all their available capacities for a given "**PP2**" reference period[3]. Checks and non-availability penalties apply.



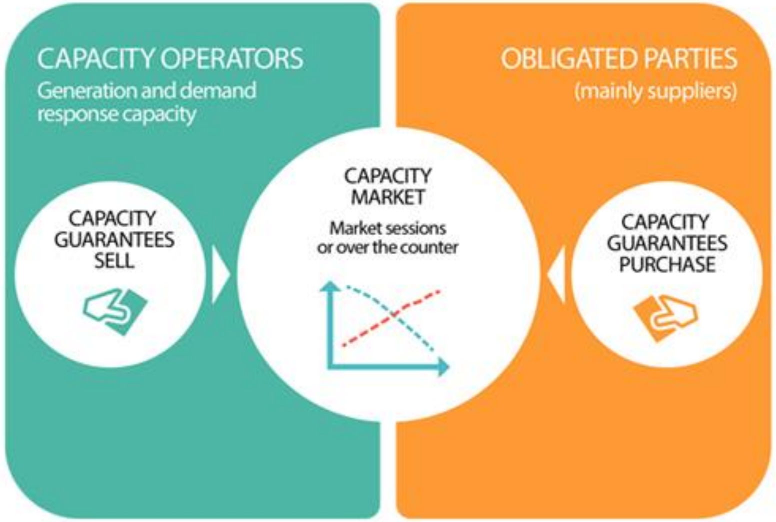
Electricity Suppliers / Network Operators

Have an obligation to secure / buy guarantees to cover peak consumption of their customers and losses. If they do not cover this there is a penalty.

Electricity Generators / DR

Certified plants and DR providers are granted free guarantees by RTE. If the availability commitment is not reached there is a penalty.

Illustration of trading in the French capacity market



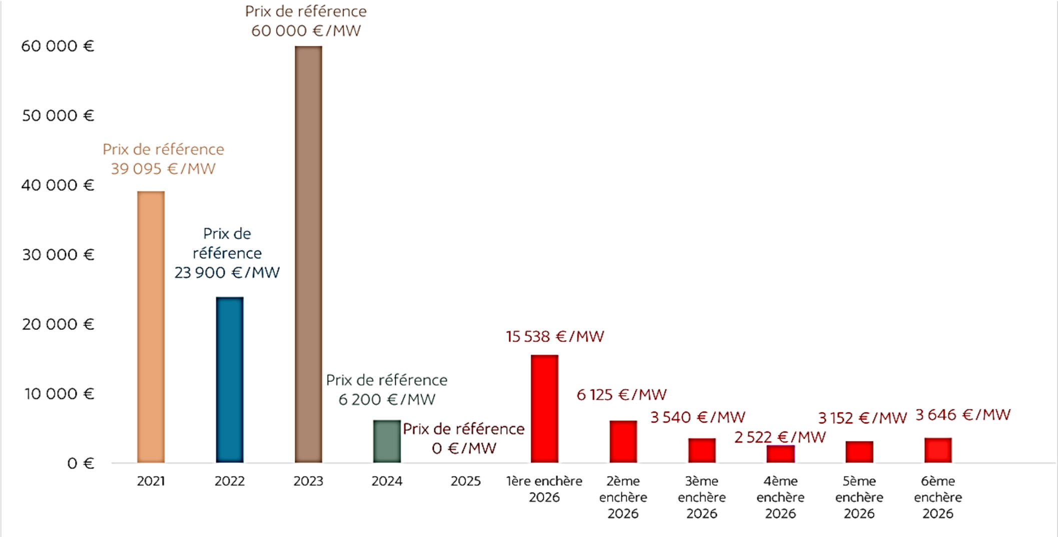
***Sources** : [1] [2] [3] RTE*

Capacity providers – especially generators – and obligated parties can buy and sell capacity certificates in organised marketplaces or bilaterally

Generators can sell their capacity either through auctions, or through bilateral transactions

- Generators can sell their capacity certificates either (i) through **auctions** organised by the power exchange EPEX Spot, or (ii) through **bilateral transactions** with obligated suppliers or consumers. The latter is known as 'over-the-counter' transactions. They may also buy back capacity certificates through these channels if they cannot honour their capacity obligations (e.g. due to unavailability of their asset) to avoid capacity imbalances.
- For a **given delivery year**, **several auctions are organised** by EPEX Spot to allow market parties to exchange capacity certificates specific to the delivery year in question. For instance, for the delivery year 2025, nine auctions took place, between October 2023 and December 2014.
- During each auction, the **capacity price** is set by the market as the **equilibrium between the offers and the demand**.

Yearly capacity mechanism reference price and 2026 auction prices (€/MW)



The reference market price is the clearing price of the last auction before the delivery year.

Sources: RTE Bilan Electrique 2020, RTE Capacity Mechanism market rules, Acciona.

Pros and cons of the decentralised approach based on the French capacity market example

Choice of structuring design	Initial Rationale	Ex-post evaluation from RTE and CRE
Market-wide mechanism	Maintaining existing capacity and reinvesting	Paradigm shift: stabilization of the tip. Perimeter of the de facto mechanism reduced with dedicated mechanisms to support load shedding, renewable energies and nuclear power (ARENH and evolutions) which are linked to the capacity market. High cost of the market-wide mechanism compared to its contribution.
Decentralisation, in terms of defining the need and contracting	Information feedback Engagement of market players	Introduction of centralised elements on request of the EC (AO LT) Uncertain interest of decentralized architecture for information feedback Source of complexity for the actors and lack of legibility
Diffuse temporality	Customized risk management Appropriate hedging strategy	Diluted liquidity in the various auctions Issues of legibility of price formation and volatility
Certification flexibility for capacity holders	Accountability of actors and customized risk management	Observation of a bias towards optimism, deviation from RTE's BP Complexity for the actors
Product / obligation: availability on PP1/PP2 days	Reflecting as best as possible the days of tension and the stakes for the security of supply	The variability of the placement of PP1/PP2 days creates uncertainty for the players
Checking the actual level availability and contribution to the peak	Improve the reliability of the device	Complexity. Only partially integrates reliability issues and does not allow for the observation of all valued capabilities

The French mechanism is complex, combining (i) a desire for precision and relevant incentives, (ii) integrating structural provisions at the request of the European authorities and (iii) taking into account the specificities of the actors and the sectors

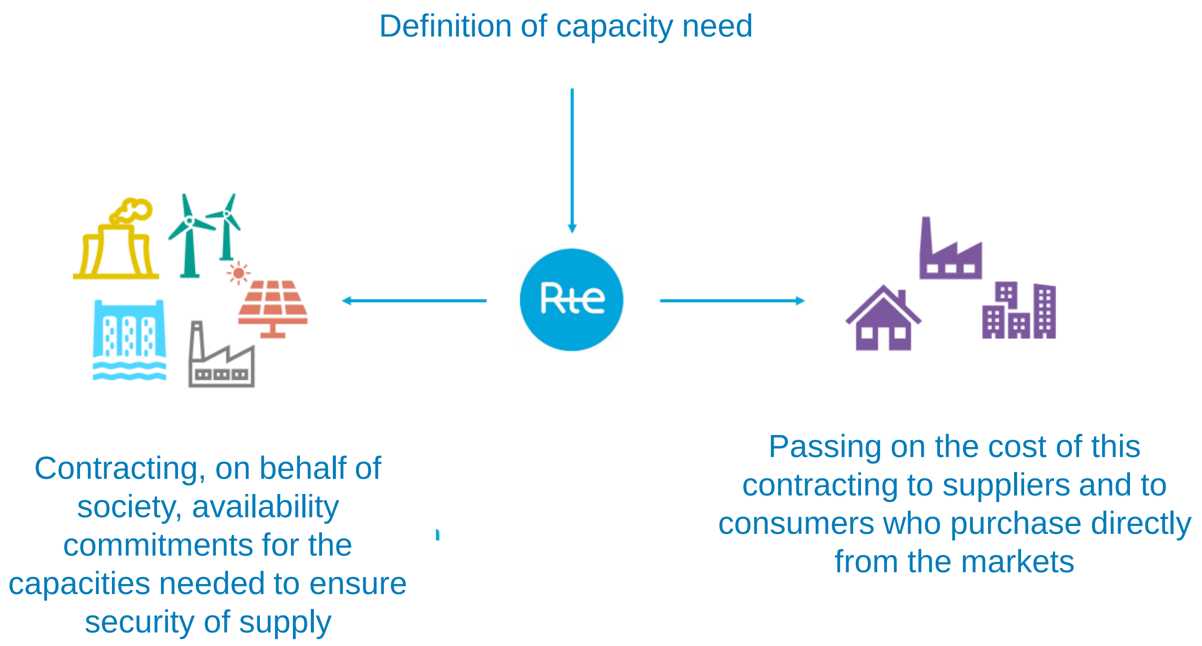
The 2025 Finance Act establishes the implementation of a new capacity mechanism in France to replace the existing mechanism

RTE has been working since 2022 on the implementation of a new CRM design for France

- As the capacity mechanism currently in force in France expires in 2026, the public authorities have mandated **RTE** to lead a **consultation on the design of the future mechanism since 2022**.

The new capacity mechanism will be based on a centralised design

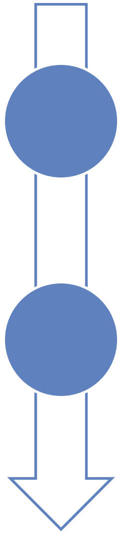
- **RTE** will **contract** the amount of capacity needed to guarantee France's **security of electricity supply** for each delivery period. Each delivery period covers an **electricity winter** spanning two calendar years.
- Contracting will be done through **auctions** to select the capacities that best meet the requirement at the **lowest cost for society**.
- **Two auctions** will be held for each delivery period: one several years in advance, and another a few months before the period begins.
- Operators who win the auction will sign a **contractual availability agreement** for the peak periods of the delivery period. They will be paid for their availability, provided it is verified.
- These availability commitments can be traded on a **secondary market**, allowing operators to transfer their commitments to others.
- The **cost** of contracting capacity will be passed on to electricity suppliers and to consumers, through a **levy collected by RTE**.



Source: RTE

More specific design elements of the new French CRM – specific design still ongoing

The auctions temporality aims at incentivizing investments in decarbonised flexible capacity



Auction Y-…: technology neutral

Auction M-…: priority given to decarbonised flexible assets

Multi-years contracts will be awarded to incentivise necessary investments to ensure adequacy.

The demand curve will be determined by the regulator CRE, based on inputs from RTE

- The definition of the **security of supply criterion** is set out in the **French Energy Code** (Article L. 141-7), and its level is determined by the minister responsible for energy through regulatory means. Currently, the security of supply criterion is set at an average risk duration of load shedding of **less than 2 hours per year on average**.
- **RTE**, would be tasked by the public authorities with **providing the data** that enables the Energy Regulatory Commission (**CRE**) to **determine** and **propose the required capacity for a given delivery period**, which will be approved by the public authorities.
- The capacity requirement would be expressed as a **demand curve relative to a period spanning two calendar years and covering the winter** (one winter forming one "delivery period"), ensuring that the **security of supply criterion** is met for this period.

A public consultation was published in February 2025, and the final design has not been published yet.

RTE and the French authorities are currently working on the operational implementation, with the new CRM expected to come into force for the **winter of 2026-2027**.

 Source: French government

In France, DSR capacities participate to specific call for tenders to complement the CRM revenues (1/2)

Context and functioning of the mechanism

- The **DSR call for tenders** is a system to **support the development of electricity consumption demand response** to reach the national objectives.
- It was approved by the European Commission in 2018 and extended in 2023.
- It provides **additional remuneration to that of the CRM**, its level depends on the CRM revenues: remuneration works as a **CfD based on the CRM remuneration level**.
- Some capacities can also get an additional remuneration of 20k€/MW/year.
- Several **options** for providing capacity are possible, at the candidate's choice.
- Capacity must be made **available on indicated days**, which correspond to the days of greatest tension on the electrical system.
- Capacities can obtain **single or multi-years contracts** (up to 10 years for certain categories)
- Only **'green' DSR is eligible**, i.e. corresponding to an actual decrease in consumption (e.g. load shedding by starting up a generator, is not eligible).

Key objectives of the mechanism

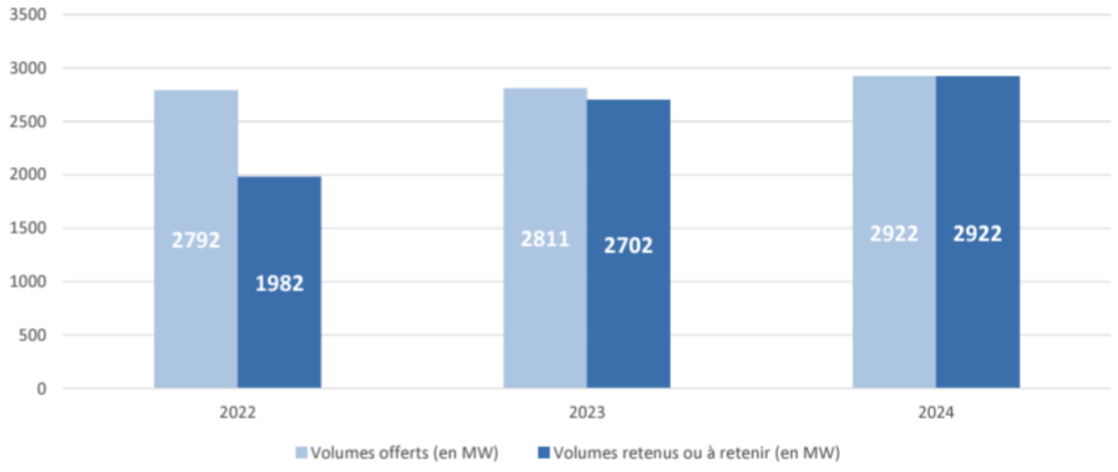
- Support the DSR sector towards maturity by encouraging DSR to participate in existing markets
- Encourage DSR to participate in the mechanisms/market that are most useful for the power system (e.g. fast and complementary reserves), through a financial bonus
- Gradually withdraw grey (=diesel) load shedding from support, through the application of a penalty for this type of DSR
- Ensure greater reliability of the service provided by DSR, through contractual incentives

The mechanism developed DSR, but has not considered flexibility needs more widely in a technology neutral approach (2/2)

Successes of the mechanism

- **Participation to the mechanism has been important since 2018**, where contracted volumes for load shedding DSR increased largely in the first years of the mechanism, going from around 400 MW in 2018 to over 1400 MW in 2021
- While in 2018, 45% of the contracts were awarded to **'grey' DSR (starting a generator)**, it only represented 9% in 2019 and was **prohibited from 2020**.
- The large increase in participation from 2020 notably comes from the **increase in the price cap**, following criticisms from the market parties on the remuneration level.
- In 2024, the majority of capacities contracted opted for the **additional remuneration** in exchange of better services for the electric system (higher number of availability hours, etc.).
- **This mechanism is targeted on DSR, and so not directly linked to a more general flexibility need** – rather kickstarting the development of a targeted technology
- **Even then, the procured volumes fall short of political objectives, however**: the French targets for DSR were 4.5 GW in 2023, towards 6.8 GW in 2028

Offered and awarded volumes in the French DSR contracting mechanism, 2022-2024 (MW)



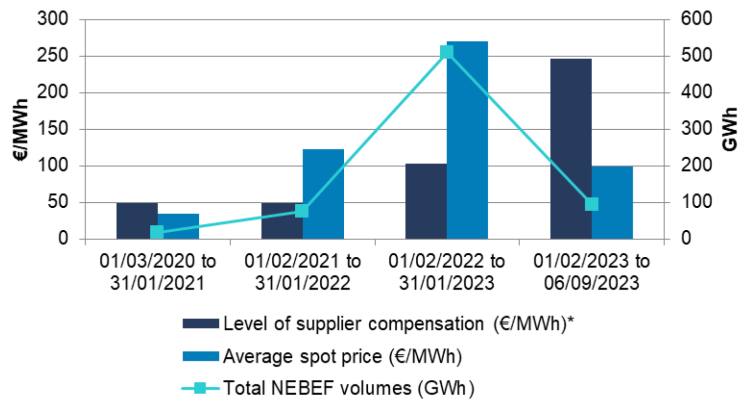
 Source: RTE, PPE and RTE .

France implemented one of the most advanced regulatory frameworks for DSR in Europe, compatible with regulated tariffs

Functioning of the mechanism

- With the Block Exchange Notification of Demand Response (NEBEF) mechanism, DSR operators sell blocks of DSR in the intraday and day-ahead markets, correspond to the volume of energy not consumed by its flexible consumers during activation periods, **without prior consent from the supplier's BRP**.
- The **correction of BRP's perimeters** and the com**pensation mechanism paid by Independent Aggregators to suppliers** allow to keep whole both the supplier and its BRP.

Comparison of spot prices, level of supplier compensation and total NEBEF volumes from 2020 to 2023



Assessment of the mechanism

+

- The NEBEF mechanism has played an important role to enable DSR development in France, by defining the roles of the different players, by:
  - providing a **regulatory framework** for the participation of Independent Aggregators in energy markets without suppliers' consent, and
  - streamlining the methodology applied by the TSO for the **certification** of DSR volumes in wholesale markets

−

- Still, **capacity remuneration through dedicated tenders and the CRM** has been the key driver of the development of DSR capacities in France and accounts for about **95%** of total DSR revenues
- DSR volumes activated in the day-ahead and intraday markets have been **relatively low**, except during periods of exceptional market conditions when a **spread** between spot prices and compensation appears
- Arguments brought forward to explain the limited volumes of DSR activated in the energy market through the NEBEF mechanism include the **low volatility and limited spikes**, and the **payment of suppliers' compensation by Independent Aggregators**.

5.4

Germany

German reserves address security of supply and grid stability issues, and are located in the south-western part of Germany

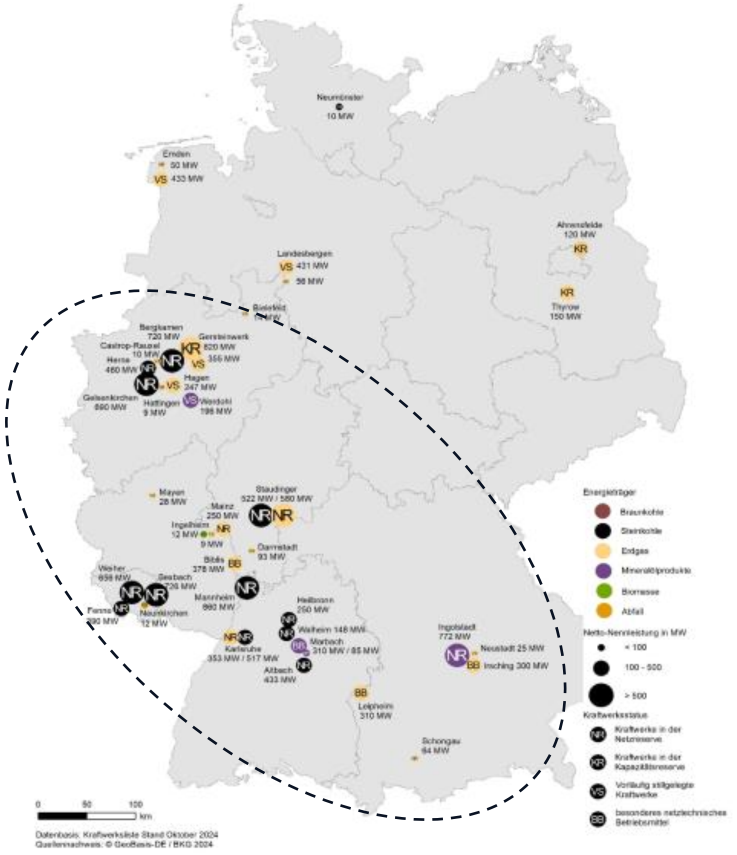
Need for reserves

- German generation mix is undergoing significant changes with **RES taking over conventional sources**, and the parallel **phase-out of nuclear and coal power plants**.
- The geographical change of the generation mix increases the flows from RES generation in the north to the demand centres in the south, resulting in the congestion on the internal transmission network.
- Centred in the middle of continental Europe, Germany sees substantial cross-border flows.
- Moreover, there is a need for back-up capacity in case the EOM does not provide sufficient supply.

Key types of reserves

- German TSOs take different measures to maintain grid stability and security of supply, including
  - **Strategic reserve**
    - Power plants are kept in the capacity reserve to support the system balance in exceptional and unforeseeable situations.
    - For the current period, the capacity reserve includes only gas-fired power plants.
  - **Network reserve**
    - The network reserve is secured from system-relevant domestic power plants that the operators wanted to shut down temporarily or permanently. In the event of additional demand, the grid reserve includes foreign, contractually committed power plants.
    - Power plants in the network reserve are provided and used to provide any missing redispatch capacity in accordance with a contractual agreement and reimbursement of costs.
- The vast majority of plants operating "outside of the market" are located in the Western and Southern part of Germany.

Location of installed capacities running outside of the market (reserve assets, 2024)



Sources: Compass Lexecon Analysis based on data from Marktstammdatenregister Abschlussbericht Systemanalysen 2022; BNetzA (2024) Monitoring report

Germany‘s strategic reserve holds capacities that are activated only in unforseen stress situations

Overview and aim of the mechanism:

- The capacity reserve was implemented in winter 2020/2021 under §13e EnWG (Energy Industry Act).
- Capacities are added through competitive tenders with a bi-annual tender volume of 2 GW.
- The reserve is additional capacity that is contracted outside the market and held in reserve.
- It is only activated under stress conditions in the system and includes plants that are about to close.
- The reserve is activated only upon request of TSOs.

Eligibility:

- Open for power generation, storage and load
- For the current delivery period (October 2025 to September 2026), 1.2 GW are in the capacity reserve, solely gas-fired power plants.

Capacity requirement:

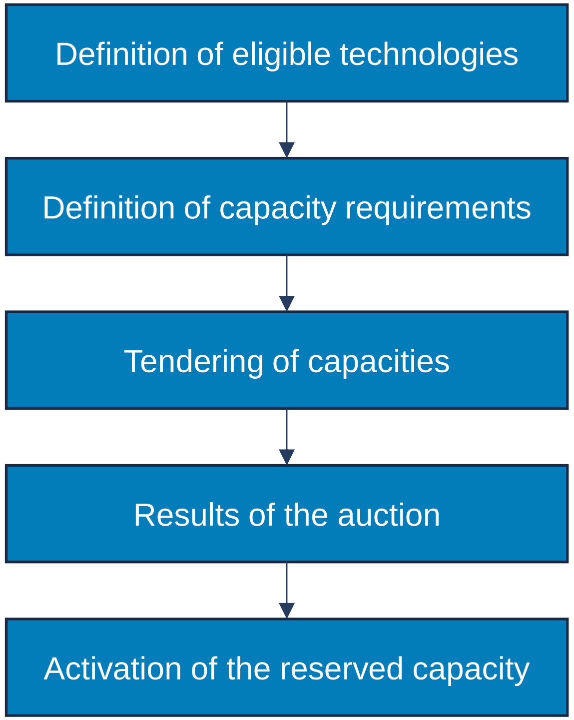
- Probabilistic analysis of resource adequacy (Monte Carlo method for estimating LOLE and ENS)

Auction procedure:

- Minimum bid size 5 MW
- Pay-as-clear

Payments:

- Capacity providers obtain annual payments
- Payments should cover all costs, including for capacity provision and depreciation of the asset
- The payments are financed via grid tariffs



Sources: Compass Lexecon analysis based on §13e EnWG, KapResV

Domestic power plants are automatically included and compensation is determined through negotiations and tenders

Eligibility:

- Historically focus on existing thermal capacity at risk of retirement, but mechanism can be extended to RES, small installations, and DSR

Product definition:

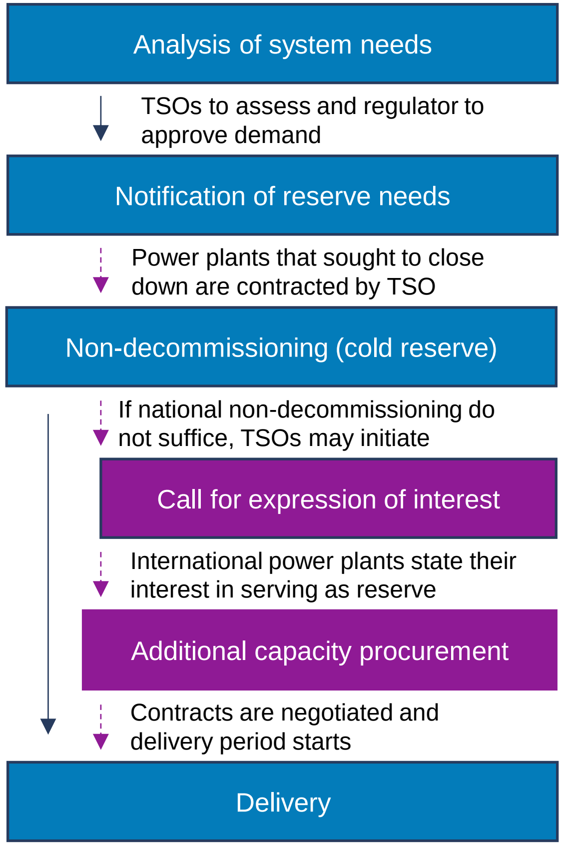
- Obligation to be at the disposal of the TSOs for re-dispatch and comply with the eligibility criteria through 2-year delivery period. May be extended by another 2 years if the plant is still system relevant.
- Facilities remunerated by the network reserve may not take part in the energy market.

Determination of demand and supply:

- German TSOs establish the need for re-dispatch capacities and network reserves based on a yearly joint system analysis. BNetzA reviews and sets amount of reserve to be procured.
- Domestic plants that do not operate or have notified their intention to temporarily or permanently close but are deemed “system relevant”. They are automatically included in the reserve.
- In case of further need, BNetzA instructs TSOs to organise a tender to other system-relevant plants of foreign operators based on their grid-related effectiveness on the needed re-dispatch

Price formation:

- Domestic plants remuneration negotiated bilaterally with the TSO and approved by BNetzA
- Domestic plants prohibited from temporarily closing down: preparing and maintaining plant in “reserve” state, operating and depreciation
- Domestic plants prohibited from definitely closing down: maintenance of plant, preparing and maintaining plant in reserve state, operating and opportunity costs
- Remuneration of foreign plants based on the outcome of the tender.
- Financing by final consumers through pass-through of net costs incurred by TSOs in network tariffs.



Sources: Compass Lexecon analysis based on BNetzA (2024) Monitoring report

The need for the strategic and network reserves is expected to remain in the coming years, however, the schemes contain some limitations

Need for strategic reserve

- The capacity reserve has the important task of safeguarding the electricity market against extremely rare or unforeseeable extreme situations for which market participants cannot or cannot adequately prepare
- This safeguarding function becomes even more important during the upcoming transformation toward a climate-neutral power plant fleet.
- Hence, the strategic reserve will continue to play an important role in the electricity system in the coming years.

Need for network reserve

- In the coming years, there will still be a need to use grid reserve power plants for redispatch measures in order to ensure system security.
- The mechanism is typically considered an interim solution until network is sufficiently expanded.

✓ **Advantages**

- Lower procurement costs, provided that the qualified existing capacities are sufficient to cover the identified residual demand
- Helps to control the pace of plant decommissioning
- Reduces the risk of overprocurement

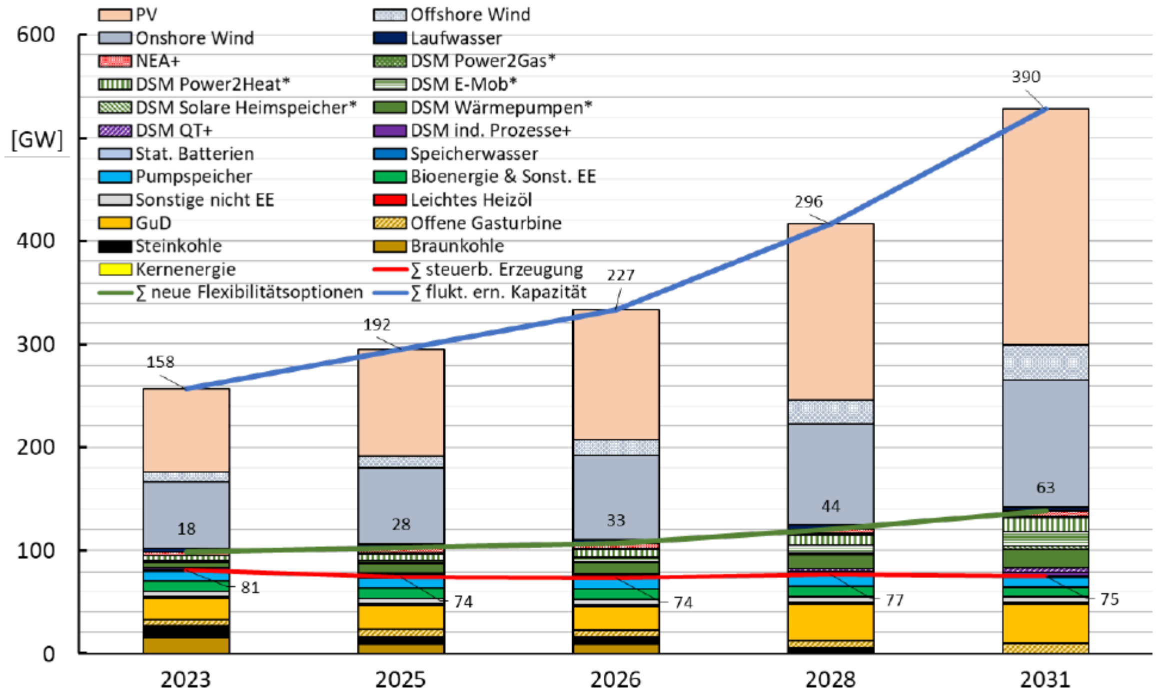
✘ **Disadvantages**

- No incentives for new investments
- Some design elements (e.g. no-return clause) potentially restrictive and impair competition in the procurement of the reserve
- Implementation complexity, but generally less complex than capacity markets
- Risk that not enough capacity is available

Sources: Compass Lexecon analysis based on BMWK 2024

Analyses show a need for 20 to 25 GW of additional dispatchable capacity in Germany to achieve RES goals and adequacy requirements

Required development of installed capacities for DELU market zone, according to BNetzA - Capacity adequacy assessment (2023) (DELU) [GW]



Adequacy analyses show that there is a need for around 20 to 25 GW of additional dispatchable capacity.

- Analyses by the four TSOs from the scenario development of the NEP 2025, the current European Resource Adequacy Assessment (ERAA 2023) of the European TSOs and the BNetzA's security of supply monitoring from 2023 indicate an additional demand for secured capacity of **around 20 to 25 GW** above and beyond this level.

In 2023 adequacy assessment BNetzA anticipates until 2031:

- **nuclear phase-out**
- **coal phase-out**

+ 232 GW of RES

+ 21,4 GW of gas capacities

+ 58,5 GW of DSR

+ 4,5 GW of backup generators

Sources: CL analysis based on Szenariorahmen zum Netzentwicklungsplan Strom 2037/2045, Version 2025; ENTSO-E (2023): European Resource Adequacy Assessment, 2023; Bundesnetzagentur (2023): Bericht zu Stand und Entwicklung der Versorgungssicherheit im Bereich der Versorgung mit Elektrizität,

Germany targets the introduction of a Power Plant Strategy, aiming to bring new gas generation, and a capacity market

The initially drafted German Power Plant Strategy (Kraftwerksstrategie) intended to drive forward the expansion of necessary capacity as a bridging instrument until the operational implementation of a capacity remuneration mechanism starting in 2028. However, following the coalition break and election of a new government, the exact design and implementation timeline of the Strategy and capacity market are unclear as of now.

Targeted tendering mechanism + market-wide CRM

Proposition by old government: Overall, 12.5GW of capacity should be auctioned in two rounds (12GW of H2-ready gas units and 500MW of LDES).

- In a first round, it foresees the auctioning[2] of **5 GW H2-ready gas-fired power plants** and **2 GW existing plants to be retrofitted to H2-ready**. The successful plants can run on natural gas for 8 years (obtaining a **CAPEX support**), before converting to green or blue hydrogen (receiving a **CAPEX and OPEX support** for the cost difference between natural gas and H2 capped at 800 full load hours per year). Additionally, **500 MW of H2-fired power plants** (H2 sprinter plants) and **500 MW long duration energy storage** (LDES) will also be auctioned.
- In a second round, It foresees the tendering of **5 GW of new built natural gas plants** with a CAPEX support for the plants awarded in the auction. There is no fuel switch requirement announced for these capacities.

High-level proposition by new government: **20 GW of gas-fired power plant** capacity by 2030 through technology-open tenders, preferably at existing power plant sites

The old government targeted a **capacity mechanism** to start in 2028. The new government has **not yet specified** the design, combination with the Power Plant Strategy, or implementation timeline. In general, the new government announced that the goal is to establish a technology-open and market-oriented capacity mechanism.

Currently, EOM may provide insufficient incentives to install dispatchable capacities that answer the system needs in a way compatible with decarbonisation goals. The concrete development of the targeted tender for flexible (decarbonised) capacity and a capacity market to ensure sufficient investments is on-going.

__Notes__: (1) Based on Federal Network Agency's 2030/31 security of supply monitoring, Entso-E ERAA (2023); (2) Starting end of 2024/early 2025. Source: BMWK (05.07.2024), Coalition Agreement of CDU/CSU and SPD.

5.5

Italy

The Italian CRM has been introduced in a context of a massive exit of ageing thermal capacity, with the need to develop new thermal plants

The Italian CRM has been introduced in a context of deterioration of adequacy margins, due to the massive exit of ageing thermal capacity.

- Between 2014 and 2019, capacity margin decreased from 25 GW (overcapacity) to 6 GW, as a result of the exit of old oil/coal plants.
- A capacity market was introduced in 2019 to ensure security of supply, by **developing or maintaining sufficient capacity taking into** account **local** network **constraints** and **directing investments locally.** Also aims to **reduce dependence on imports.**

Capacity auctions are held regularly, for different timeframes and contract lengths

- In the initial implementation phase, only **1 auction is held per delivery period**, **several months to 3 years before delivery**. In the final implementation phase (for which the time horizon has not yet been given), 1 main auction will be held 4 years before delivery with several adjustment auctions 3, 2 and 1 year before delivery.
- The standard duration of the availability obligation is 1 year for existing capacities, with activations during periods of price peak, and availability tests.
- Capacity units with investment costs above a certain threshold (200 €/kW) are eligible to multi-year capacity contracts (15 years).

Key features of the Italian CM

1	Centralised	Terna is responsible for operating the auctions, calculating administered demand
2	Market-wide w/ eligibility	All eligible capacities can participate to the competitive bidding procedure
3	Technology neutral	All technologies without on-going operating subsidies are allowed to participate in the CRM. However, they are subject to the application of a derating factor representing the degree to which the technology enhances security of supply
4	Intermediate Price Cap	Lower price cap for existing capacity than for new capacity (33€/kW/year for existing capacities and 75€/kW for new capacities in the first three auctions)
5	Reliability Option	Profits derived from energy market in scarcity periods above a certain threshold (strike price) will have to be paid back
6	Long-term contracts	Depending on investment thresholds, participating capacities can secure long-term contracts
7	Penalties	Penalties are applicable if the availability obligation is not fulfilled

Sources: *Commission Decision of 7.2.2018 on State aid SA.42011 - (2017/N): Italy - Capacity Remuneration Scheme*
Notes: *All € figures are expressed in real 2023 unless otherwise stated*

In the last three auctions, demand for capacity has been met, but no DSR capacity has been procured

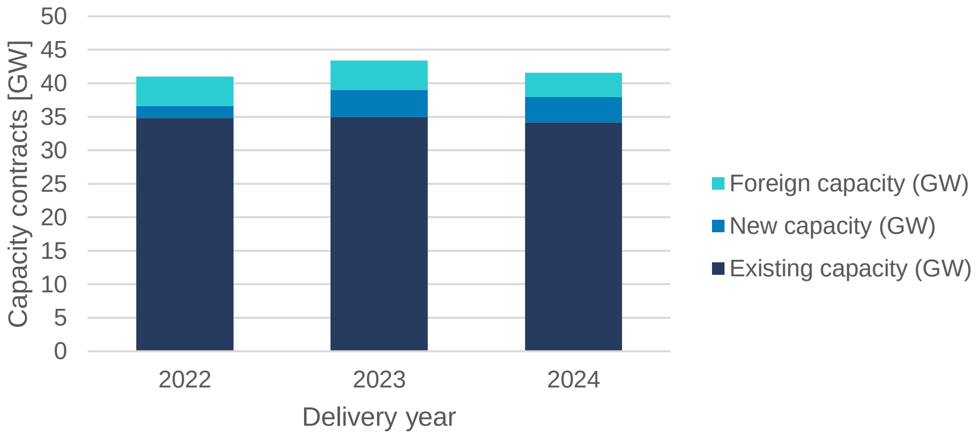
The full capacity need was secured in the past 3 auctions

- **41 to 43.6 GW of capacity has been secured in the first 3 auctions, among which no DSR capacity.** No adjustment auctions have been carried out**.**
- **Clearing prices** reached the **intermediate and global caps (33€/kW/year for existing capacities and 75€/kW for new capacities)** in the first 3 auctions, potentially due to a lack of competition between capacities (e.g. all the domestic capacity participating to the auction was awarded in 2024).

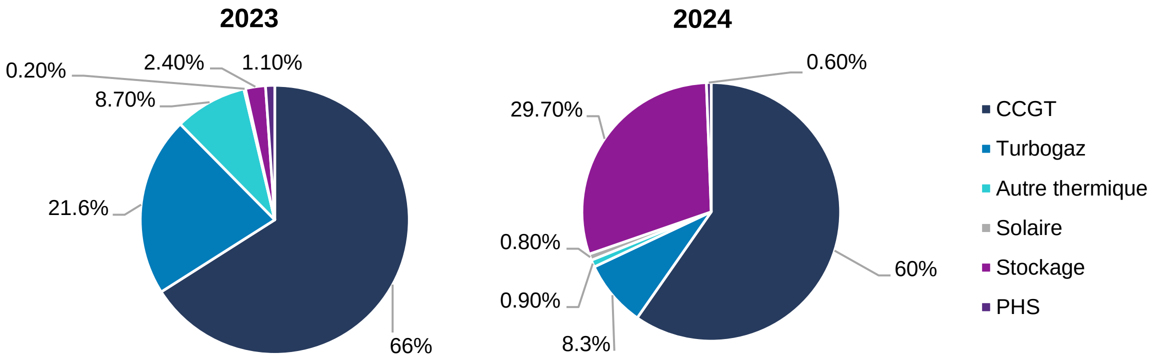
Italy is planning to extend its capacity market auctions until at least 2028

- Italy is planning to extend its capacity market auctions until at least 2028, and projects an increasing need for capacity, with a projected peak load of 64 GW for 2028 and 67 GW for 2033.
- The regulator ARERA has launched a consultation, proposing the price cap to be raised – 47-8€/kW for existing capacities and 85-6 €/kW for new capacities.

Capacity contracted per delivery year in the Italian CM



Technology share of the new capacities contracted in the Italian CRM (delivery 2023, auction held in 2019)



Sources*: Terna, CRM auction results ; MontelNews*
Notes*: All € figures are expressed in real 2023 unless otherwise stated*

Even if the Italian CM is in principle technology-neutral, in practice certain requirements make participation of DSR unattractive

The capacity market's failure to attract demand-side resources can be attributed in parts to several participation requirements. Moreover, the existence of the more profitable ancillary service UVAM project (c.f. dedicated section) may weigh on participation. The two programmes are not compatible, so demand-side units are forced to choose.

Independent aggregators are not allowed to participate	**Participation is only allowed through the generator own connection point, therefore independent aggregators are excluded**
No capacity payment	**Unlike for power generators, clearing DSR capacity do not receive a capacity payments but are simply exempted from paying capacity charges on electricity price**
Competition with UVAM program	**Market participants cannot combine participation in the UVAM program and capacity contract**
Remote load disconnection requirements	**Demand units must guarantee the possibility to be remotely disconnected by the TSO within 5 mins.**

__Notes__: According to SmartEN (2022) in Resource Adequacy Mechanisms 2021, capacities do not receive capacity payments, do not pay or receive scarcity rent, and are in exchange exempted from funding the mechanism. Thus, the lack of a direct payment might limit the types of assets that will participate in the mechanism.All € figures are expressed in real 2023 unless otherwise stated

Italy further introduced a support scheme for non-fossil flexible resources targeted at centralised hydro pumped and battery storage

The support scheme for storage assets has been implemented to maintain system stability in the face of increasing RES capacities.

- Italy's substantial growth in RES increases the risk of overgeneration and RES curtailment to maintain system stability. Hence, the need for storage is growing.
- The existing market design does not incentivise investments in storage assets (e.g. high CAPEX, uncertain long-term revenues).
- Hence, Italy implemented a support scheme targeted at the deployment of non-fossil flexible resources in 2023. More specifically, Italy's scheme targets the development of centralised/grid-scale storage.

Under the scheme, regular auctions will take place until the end of the scheme, set for December 2033.

- The scheme does not foresee fixed frequencies for auctions, but rather regular auctions depending on the evolution of storage needs, development of RES and grid constraints, as well as available budget.
- Under consideration of these aspects, Terna will propose capacity volumes for each auction. Each auction must meet minimum notice requirements (180 days after publication of auction rules, 60 days after publication of technical/economic parameters and auction announcement).
- The targeted capacity is 3 GW/24 GWh by 2025/2026 and 9 GW/71 GWh by 2030.

Key features of the storage support scheme

Type of scheme	Competitive auction with auction volumes determined by Terna.
Technology scope	Technology-specific auctions for commercially mature storage technologies. Separate auctions for technologies with significantly different lifetimes or lead times (e.g. batteries vs. hydro-pumped storage).
Control and type of product	Storage will be operated via a centralised system managed by Terna and offered to market participants as time-shifting products.
Market participation	Residual capacity participates in ancillary and balancing markets.
Contract duration	Contract lengths aligned with lifetime of technology (e.g., 13 years for battery storage, 40 years for hydro-pumped storage).
Payments	Fixed annual payment per MWh of capacity as bid in auction, paid in monthly tranches.

Source: Based on European Commission

5.6

Greece

Greece implemented a transitory electricity flexibility remuneration mechanism in 2019

Context:

- Increased **RES penetration** in Greece led to the "duck curve effect", creating challenges to manage the generation variability.
- The transitory flexibility scheme aimed at **remunerating the availability of eligible flexible generation capacity** necessary to provide the flexibility needs and was approved for 12 months from its adoption (ended in 2020).

Functioning of the mechanisms:

- The TSO **procured the required flexible capacity centrally** and the level of the remuneration was set through an **auction**. 4.5 GW of flexible capacity was procured
- Participation to the tender was conditional on **predefined eligibility and availability criteria** for the delivery period. Actual availability was monitored by the TSO.
- In exchange for the remuneration, participants had to **bid at all times** in the market.
- This first mechanism, open to all flexible technologies, was set to work **until the balancing market is mature enough**. Most of the contracted capacity came from gas units.

Key objectives of the first Flexibility Remuneration Mechanism

- **Implement a remuneration framework for flexibility services providers**
- **Support the storage sectors towards maturity**
- **Ensure provision of flexible capacity to fulfil the identified system need**

Source: Compass Lexecon analysis based on European Commission, ADMIE, auction results, European Commission

Following the transitory scheme, Greece launched a storage-specific scheme in 2022

The support scheme for storage assets aims to reduce the need for RES curtailment and bridge network investments in congested areas.

- Greece launched a new support mechanism solely open to storage. Before, no standalone storage facilities existed in Greece (except for to hydro units used mainly for generation).
- The storage assets are aimed to support the integration of 9 GW of new RES and to complete the lignite phase-out by 2028.

The scheme awards an investment grant for the development and construction phase, as well as a CfD for the operational phase.

- The scheme takes the form of an investment grant (for up to 50% of CAPEX) and a CfD (10 years).
- Both support measures are funded via the Recovery and Resilience Facility as well as levies on electricity suppliers.
- The targeted capacity is 900 MW of storage capacity.

Greece is also considering the implementation of a CRM to be articulated with the storage support mechanism.

- The flexibility requirements as part of the CRM and the details of the articulation with storage tender remain uncertain.

Key features of the storage support scheme

Type of scheme	Competitive tenders managed by the regulator.
Technology scope	Open to all mature storage technologies but tailored for BESS (especially Li-ion). Must provide at least 2-hour discharge.
Control and type of product	Storage must be controllable via TSO systems.
Market participation	Integration in all electricity markets (especially balancing) is required. PPA not allowed.
Contract duration	10-year CfD
Payments	Up to c. 220k EUR for investment grant, and annual support through two-way CfD.

Source: Compass Lexecon analysis based on European Commission

5.7

Poland

PSE holds several auctions per delivery year to ensure sufficient available capacity in the medium- and long-term

The Polish capacity mechanism was introduced to ensure sufficient available capacity and address adequacy concerns in the medium and long term in a cost-effective and non-discriminatory way.

- At the time of the introduction of the CM, the Polish authorities predicted an adequacy problem from 2020 onwards (LOLE of 175h/yr in the base case, above the chosen 3h failure criterion), due to the shutdown of old plants that had become inefficient and uneconomic.
- Electricity shortages had already been observed during the summer of 2015 (overheating and shutdown of coal plants due to low river levels during the heat wave).
- The mechanism was needed due to a missing money issue and challenge of securing investments in controllable means.

PSE started to hold auctions in 2018 and has set a price cap.

- Following state aid approval by the EC in 2018, the first auction was held with delivery in 2021, 2022 and 2023.
- PSE conducts main auctions as well as supplementary auctions if the amount of contracted capacities is not sufficient.
- PSE determines price caps which is currently set at 72 EUR/kW.
- The cap aims to limit the possibility of exercising market power in case of limited competition and to prevent new units from covering all their fixed costs with the CM.

Key features of the Polish CM

	Feature	Description
1	Centralised	PSE operates the auctions and sets the capacity required to meet the failure criterion (LOLE 3 hours).
2	Market-wide w/ eligibility	All eligible capacities can participate to the competitive bidding procedure.
3	Technology neutral	Exclusion of capacities already benefiting from "operational aid" (i.e. RES support). Inclusion of capacities with "investment aid" (e.g. free allowance under the ETS), but aid is deducted from capacity payments. Special clause securing capacity contracts awarded to coal plants before Dec 2019 to support the construction of new units
4	Availability obligation	“Load-following" obligation, i.e. if x% of total capacity is needed to meet demand, each capacity will be required to provide up to x% of its total capacity obligation. Obligation and penalty proportional to the actual need of the system at all times.
5	Long-term contracts	Participating capacities can secure long-term contracts.
6	Penalties	Penalties are applicable if the availability obligation is not fulfilled.

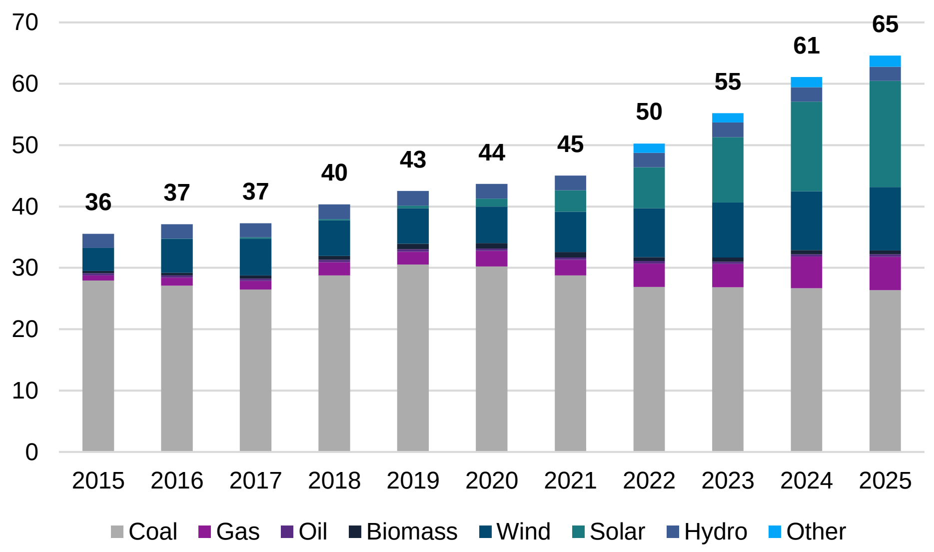
Source: Based on European Commission, PSE

The initial objectives of the CM (incl. security of supply) remain valid, but the scheme evolves with the need to diversify the generation mix

The introduction of EU emission limits for CM hinders new investments in coal-fired power plants in Poland's already fossil fuel-heavy generation mix.

- The founding objectives of the CM (security of supply, cost control and contribution to decarbonisation objectives) remain valid but the CM has to be adapted to meet the objectives of diversification of the mix.
- In particular, the Polish National Energy and Climate Plan provides for the redeployment of the dispatchable base to gas, nuclear (construction of 6 to 9 GW of nuclear power from 2033), and storage, as well as the development of renewables (especially offshore wind).
- The EU emission limit for CRMs implies that generation units emitting more than 550 kg of CO_2/MWh will lose eligibility for state aid under the capacity market as of July 2025.
- However, Poland has decided to extend participation until the end of 2028 to ensure security of supply during a transitional period.
- This transitional period will give emission-intensive units time for modernization or replacement with low-emission alternatives.

Installed generation capacity in Poland (in GW)



Source: Compass Lexecon analysis based on European Commission, Dentons, Energy Instrat

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