



Axpo Energy Reports

# Gas energy



# Introduction

A secure, affordable and sustainable electricity supply is fundamental to the functioning of Swiss society and the economy. Today, Switzerland benefits from very good conditions for a reliable supply thanks to hydropower, nuclear power, new renewable energies and its central location in the European power grid.

In the coming decades, this position will come under pressure unless suitable countermeasures are taken. The electrification of mobility and heating, in addition to population growth, are likely to significantly increase the demand for electricity. Rising energy demand of data centres, cloud services and generative AI further contribute to this trend. At the same time, the planned phase-out of nuclear power will eliminate a substantial proportion of domestic electricity production in the long term.

The winter half-year are increasingly in focus. Switzerland already consumes more electric-

ity in winter than it produces. In the darker months of the year, the demand for heat is higher and people generally spend more time indoors, which increases the power consumption of electronic devices and lighting. In addition, hydropower produces more electricity in summer due to the seasonal discharge profile, which includes a high proportion of run-of-river water in the summer half-year. The current expansion of renewable energies in Switzerland and neighbouring countries is also largely based on solar energy, which generates most of its yield in the summer half-year. The seasonal difference between summer surpluses and winter deficits is increasing, making a secure winter supply increasingly difficult.

In addition to close cooperation with neighbouring countries and the EU, the development of reliable, affordable and sustainable domestic electricity production is needed to secure the electricity supply in the future. In

the Axpo Energy Reports, we look at four technologies that can substantially increase domestic electricity production in winter: Wind energy, new nuclear power plants, solar energy and gas-fired power plants.

This report examines the technological, economic, legal and environmental implications of potentially expanding gas-fired power plants to hedge Switzerland's electricity supply. It also sets out in concrete terms which regulatory and social framework conditions are necessary for the construction of gas-fired power plants. The report focuses on the operation of large, market-active gas-fired power plants. The report is not intended to be a position paper and does not assess whether an expansion of this technology is necessary to secure winter supplies by 2050. It only describes the prerequisites that have to be met for the construction of a market-active gas-fired power plant.

**This report deals with the construction of new market-active gas-fired power plants in Switzerland by 2050.**

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<b>FOEN</b>	Federal Office for the Environment	<b>KG</b>	Federal Act on Cartels and Others Restrictions on competition SR 251
<b>BECCS</b>	Bio-Energy Carbon Capture and Storage	<b>KIG</b>	Federal Act on Climate Protection Goals, Innovation and strengthening energy security SR 814.310
<b>SFOE</b>	Swiss Federal Office of Energy	<b>LCOE</b>	Electricity generation costs (Levelized Cost of Electricity)
<b>BVU</b>	Department of Construction, Transport and the Environment	<b>LNG</b>	liquefied natural gas (Liquefied Natural Gas)
<b>CCS</b>	Carbon Capture and Removal	<b>LRV</b>	Ordinance on Air Pollution Control SR 814.318.142.1
<b>CDR</b>	Carbon Dioxide Removal	<b>NET</b>	Negative emission technologies
<b>CO<sub>2</sub></b>	Carbon dioxide	<b>PoS</b>	Proof of Sustainability
<b>CO<sub>2</sub>-eq</b>	Carbon dioxide equivalents	<b>RLG</b>	Federal Act on Pipeline Systems for Transport liquid or gaseous combustibles or fuels
<b>DACCS</b>	Direct Air Carbon Capture and Storage	<b>RPG</b>	Federal Act on structure plan SR 700
<b>ETS</b>	Swiss Emissions Trading System	<b>SAF</b>	Sustainable aviation fuels (Sustainable Aviation Fuels)
<b>EnG</b>	Energy Act SR 730.0	<b>CHP</b>	Combined heat and power
<b>EU ETS</b>	European Union Emissions Trading System		
<b>FLH</b>	Full load hours		
<b>GasVG</b>	Draft Federal Act on the Gas Ordinance		
<b>CCP</b>	Gas-and-steam combined cycle power plant (Combined Cycle Gas Turbine, CCGT)		
<b>GoO</b>	Guarantee of origin		
<b>HVO</b>	hydrogenated vegetable oils Hydrotreated Vegetable Oil		

### Why do we use the term "low-emission" in this report?

This report covers both fossil fuels and low-emission alternatives such as bio-gas, renewable hydrogen and certificates from negative emission technologies. These alternatives enable the (almost) decarbonised operation of gas-fired power plants, but still generate greenhouse gas emissions over their life cycle and are therefore referred to as "low-emission". The associated life-cycle of emissions are shown in this report.



01

Summary

**Some electricity is currently generated from gas in Switzerland primarily in decentralised plants for the simultaneous production of electricity and heat for industrial processes and district heating networks, as well as in reserve power plants. Large, centralised gas-fired power plants that participate in the electricity market and can generate market revenues do not exist. Owing to their flexibility, such plants would harmonise well with fluctuating generation from renewable energies and could therefore make a substantial contribution to the winter electricity supply. This report focuses on such potential market gas-fired power plants in Switzerland.**

In Europe, these power plants are predominantly operated with fossil natural gas and are subject to the European Emissions Trading System (EU ETS), which requires certificates for every tonne of carbon dioxide emitted. Several possible solutions exist for operating gas-fired power plants with low emissions, but each present different challenges and have so far seen limited application:

- **Renewable methane** is already being fed into the gas pipeline network as biogas (partially processed or processed into biomethane). However, this has limited expansion potential.

- **Carbon dioxide removal (CDR)** allows the CO<sub>2</sub> emitted to be offset elsewhere using negative emission technologies (NET). Only a few and very expensive CDR certificates are currently available. The implementation of CDR in Switzerland requires a domestic and European CO<sub>2</sub> infrastructure.
- **Carbon capture and storage (CCS)** captures CO<sub>2</sub> at source but requires additional investment and reduces both the efficiency and operational flexibility of the plant. Implementing CCS also requires a domestic and European CO<sub>2</sub> infrastructure connected to the plant.

- **Renewable hydrogen** serves as an alternative, low-emission fuel, but it is expected to remain very expensive for the foreseeable future. It also requires a domestic and European infrastructure to support its use.
- **Renewable liquid fuels** (e.g. e-methanol) do not require any additional infrastructure, but are very expensive and therefore more suitable for reserves.

There are **suitable sites for gas-fired power plants in Switzerland**, but their number is limited. While large thermal power plants already exist in the European region and new gas-fired power plants can be built in their vicinity due to good location conditions such as electricity and gas grid connections, this option does not exist in Switzerland. The choice of location is further restricted when the potential use of CCS and /or operation with hydrogen, along with their associated infrastructure, is considered. Additionally, the timing of the development of European CO<sub>2</sub> transport and storage infrastructure, as well as hydrogen infrastructure, is uncertain and

cannot be expected before the 2040s at the earliest.

Although market-based gas-fired power plants can in principle make an important contribution to **security of supply** due to their taxable generation, this contribution is limited in Switzerland: As there are no significant domestic gas storage facilities, Switzerland is completely dependent on foreign supplier countries and transit states and is therefore directly exposed to geopolitical crises and shortages. Possible solutions include improved institutional hedging of foreign storage capacities, continued use of dual fuel systems with liquid fuels as a fall-back option, or the development of our own domestic storage facilities. However, the latter has so far proved to be particularly challenging.

**Social acceptance** of gas-fired power plants in Switzerland is currently low, but it is likely to increase if plants are operated using low-emission solutions. Renewable methane, hydrogen and renewable liquid fuels tend to be more readily accepted. However, the credibility of the evidence is likely to be decisive for CDR.

Switzerland currently has **no suitable regulatory framework** for gas-fired power plants active on the market. Although gas-fired power plants are not banned at federal level, or in the cantons in question, there is no **subsidy scheme for this technology**. In addition, two regulations make the expansion of market-active gas-fired power plants in Switzerland virtually impossible. 1. Gas-fired power plants fuelled with natural gas face a double burden: they must purchase certificates for CO<sub>2</sub> emissions in the emissions trading system, and they are also subject to the national CO<sub>2</sub> levy. As a “Swiss Finish,” this **additional domestic CO<sub>2</sub> levy**, which is not effectively reimbursed for gas-fired power plants, results in a substantially higher impact on gas-fired power plants in Switzerland compared to surrounding Europe. The CO<sub>2</sub> levy also has to be paid for biogas, although low in emissions, if it is imported via the gas grid. At CCS, the CO<sub>2</sub> levy also has to be paid for the amount of CO<sub>2</sub> captured.

In addition, there are cantonal regulations on the use of waste **heat** when using fossil fuels. In general, waste heat from gas-fired power plants must be used when operating on fossil natural gas. However, it is not clear whether the use of gas turbine waste heat in the downstream steam cycle of a combined-cycle gas and steam power plant is sufficient to achieve the required overall energy efficiencies. If this were not the case, large gas-fired power plants would seem unthinkable, as a third-party buyer for heat in correspondingly large, fluctuating volumes does not seem realistic. Explicit regulation on this would provide timely clarity.

Appropriate adjustments would be necessary to create **viable framework conditions**. Firstly, a support mechanism for secured capacity should be introduced, for example in the form of a market for capacity. Secondly, fossil-fuelled thermal power plants should be exempt from the national CO<sub>2</sub> levy if they already participate in European emissions trading. This would avoid the current double burden and create a level playing field with plants in the EU. The same principle should also apply to all low-emission solutions that



are currently subject to CO<sub>2</sub> levy. Thirdly, the steam turbine cycle of a combined-cycle power plant should be legally recognised as sufficient waste heat utilisation of the gas turbine.

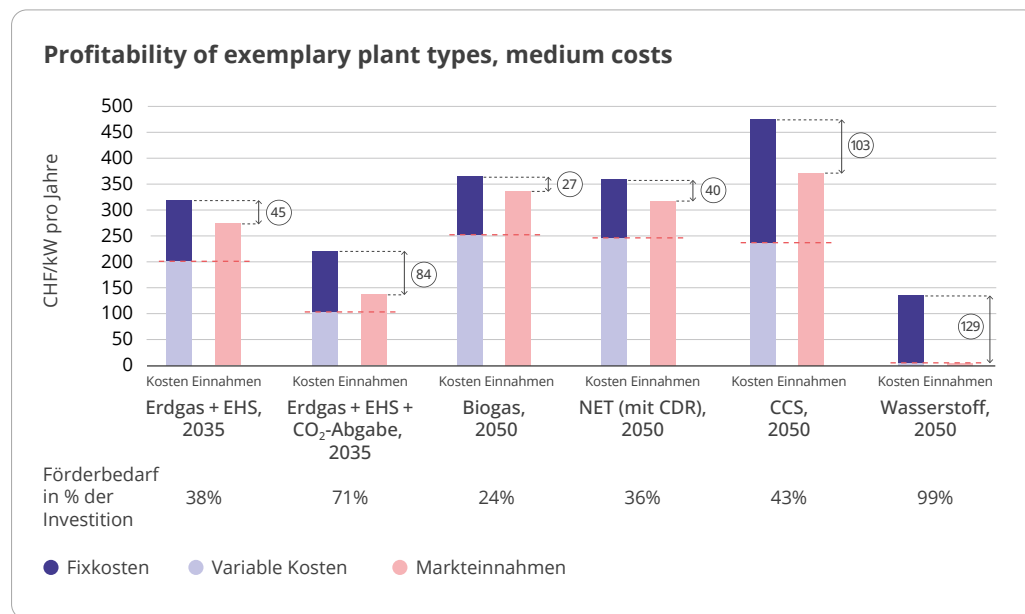
It is expected to take 10 to 15 years from the creation of these framework conditions – via tenders in the capacity market – through to authorisation, planning, construction and commissioning. This means that market-active gas-fired power plants **would only be available from 2035 at the earliest – provided the necessary framework conditions are created in time**, and implemented in parallel as far as possible.

From an economic point of view, if the double burden of the Swiss CO<sub>2</sub> levy is eliminated, operating a combined cycle power plant **using natural gas and acquiring certificates in emissions trading** is the most attractive option for investments around 2035 (see Figure 1). Nevertheless, as with all other power generation technologies, this would also require receivables for economic operation. In this case, however, the receivables would be comparatively low **due to the significant ex-**

**pected market value** of the electricity generated.

At this time, low-emission alternatives such as biogas, CDR or renewable liquid fuels are unlikely to be competitive in the European electricity market and their use will mainly serve as a reserve. As **reserve power plants** are primarily kept for rare shortage situations, they do not generate any market income. As such, their costs must be fully covered by subsidy instruments. Accordingly, they **require significantly more government subsidy** than market-active gas-fired power plants.

In view of the legally enshrined **2050 net-zero target**, a transition to low-emission solutions is necessary. By then, significant **cost reductions** and **increasing competitiveness** are to be expected, especially for **biogas, CDR and CCS**. Their costs are likely to increasingly approach those of natural gas plus emission certificates, making their use more realistic during periods of high prices. Low-emission technologies are also expected to be increasingly used in gas-fired power plants across the rest of the EU. In general,



**Figure 1:** Fixed costs are investments in gas-fired power plants, which will decrease slightly by 2050. In the case of CCS plants, investments in the CO<sub>2</sub> capture plant are also taken into account; in the case of hydrogen power plants, a surcharge is applied for the correspondingly designed turbine. Variable costs and market revenues differ between technologies and generally rise with increasing use of the system. Gas-fired power plants that operate in the market and generate corresponding revenues can cover part of their fixed costs, thereby reducing the level of subsidy required. Example: Hydrogen is used due to the high marginal costs in our Model hardly used: Receivables would have to cover the total fixed costs accordingly (similar to Reserve power plants).

however, market revenues alone will not be sufficient to fully cover the costs of any of the technologies analysed. Although the proportion of costs covered by market revenues will increase by 2050, subsidies will continue to be required. Plants running on hydrogen or renewable liquid fuels are unlikely to be used in 2050 due to the high fuel costs.

However, the uncertainties surrounding electricity generation costs in 2050, the development of the required infrastructure, and the availability of the fuel in sufficient quantities remain considerable. However, the **flexibility of gas turbine technology** makes it possible to switch to the most suitable low-emission solution at a later stage. For some of these options, gas-fired power plants would have to be retrofitted accordingly. Ideally, additional space requirements and the future location of planned hydrogen and /or CO<sub>2</sub> infrastructure (for CCS) should be considered

from the outset. **Renewable methane**, on the other hand, can be used **either in its entirety** or as an **admixture** without technical adjustments. The big advantage of offsetting measures such as CDR is that they can be implemented in the most appropriate locations (e.g. close to CO<sub>2</sub> storage sites) and with efficient capital use (e.g. no H<sub>2</sub> infrastructure needed to reach the plant) despite fewer operating hours per year.

From a macroeconomic perspective, it is important to note that investments in power plant components and fuel expenditure account for around 50 percent of the total costs of a gas-fired power plant, and are almost entirely channelled abroad. Over a gas-fired power plant's lifetime, this results in a domestic value added share of only 47 percent, which means that the expenditure of 1 Swiss franc leads to a domestic value added of only 47 cents. The investment in a 500 MW gas-

fired power plant in Switzerland generates an average of 265 full-time equivalent jobs per year over the lifetime of the plant.

A natural gas-fired power plant causes relevant greenhouse gas emissions: Each TWh of natural gas electricity (~1.7 percent of Swiss electricity demand) would generate an additional 0.32 Mt-CO<sub>2</sub>eq, which corresponds to 0.8 percent of the current annual emissions in Switzerland; looking ahead to 2050, it would be 2.6 percent of the 12 Mt-CO<sub>2</sub>eq unavoidable greenhouse gas emissions that must be offset via CCS or negative emission technologies. Apart from greenhouse gas emissions, the environmental impact is minimal: Gas-fired power plants require little land, generate hardly any hazardous waste and have negligible demand for critical raw materials.



02

## Technology

There are currently no market active Gas-fired power plants; in addition to natural gas, future low-emission solutions would also be considered

### In brief

- Currently, Swiss gas-fired power plants are either decentralised combined heat and power (CHP) plants designed for industrial processes and district heating networks, or reserve power plants. Switzerland currently has no large, centralised gas-fired power plants that operate on the electricity market (market-active).
- Various options exist for using waste heat from gas turbines. Combined-cycle gas turbine (CCGT) plants use the waste heat from the gas turbine in a steam turbine to generate additional electricity. As with CHP plants, this heat can also be decoupled and used for industrial processes or district heating. For market-active gas-fired power plants, however, such heat extraction is practically impossible, as there are typically no sufficiently large and flexible heat consumers available.
- Today, CCGT power plants in neighbouring European countries are predominantly operated with fossil natural gas. These plants fall under the emissions trading system and must purchase certificates for every tonne of CO<sub>2</sub> emitted.
- Various low-emission solutions are possible for operating gas-fired power plants:
  - i) Renewable methane is already being fed into the gas pipeline network as biogas, but has limited potential within Europe.
  - ii) CDRs make it possible to offset the CO<sub>2</sub> emitted elsewhere. However, the certificates needed are currently scarce and very expensive. Requires a domestic CO<sub>2</sub> infrastructure for negative emissions in Switzerland and are not currently recognised in the emissions trading system.
  - iii) CCS captures CO<sub>2</sub> at source but requires additional investment and reduces plant efficiency and flexibility. Here too, a domestic CO<sub>2</sub> infrastructure is needed.
  - iv) Hydrogen serves as an alternative, low-emission fuel, but is very expensive for the foreseeable future and requires a European infrastructure.
  - v) Renewable liquid fuels require hardly any additional infrastructure, are very expensive and therefore more suitable for reserves.
- It remains uncertain whether, when and where a European infrastructure for CO<sub>2</sub> and hydrogen will be developed – likely not before the 2040s at the earliest.
- If gas-fired power plants are built in advance of such infrastructure, sites should be chosen that are suitable for retrofitting low-emission solutions. However, remaining open to multiple solutions severely limits the number of suitable locations.
- Switzerland does not have any large gas storage facilities, which limits energy supply security with gas. Possible solutions include constructing gas storage in Switzerland, improving institutional hedging of gas storage abroad or – as in the past – using a "dual-fuel solution" with liquid fuels as a back-up.

## 2.1 Current buildout

To date, gas-fired power plants have tended to play a secondary role in Switzerland: In 2023, 0.7 TWh was generated based on natural gas and biogas. This electricity was generated in CHP plants, which are typically decentralised with an electrical output of less than 1 MW. These plants provide heat for industrial processes or thermal grids and feed in electricity as a by-product.

In addition to these decentralised CHP plants, the federal government operates three reserve gas-fired power plants. These were procured or contracted by the federal government in response to the impending electricity shortage in winter 2022 /23<sup>1</sup>. Located in Birr, Cornaux and Monthey, they have a combined output of 336 MW. They are only started as a last resort, when market mechanisms and other instruments – such as the hydropower reserve – are insufficient to ensure supply.

The contracts for these three power plants expire in spring 2026. However, reserve power plants should continue to play a role in securing the electricity supply in Switzerland. Five projects with a total capacity of 583 MW were awarded in a tender<sup>2</sup>. However, these will be available from 2030 at the earliest. As an interim solution, the federal government has signed an existing test plant in Birr (250 MW from February 2027 to 2030).<sup>3</sup>

## 2.2 Technological development

The use of waste heat plays a decisive role in the design of a CHP plant. Waste heat is used for industrial processes or thermal grids, significantly increasing efficiency compared to pure steam boilers without electricity generation. CHP plants are typically designed around existing heat or steam demand and operated in a heat-led manner. This means that the system produces heat when it is needed, and the electricity generated is a

by-product. District heating networks mainly require heat in winter, whereas industrial processes often need heat almost all year round. Typical Swiss CHP plants generate heat in the range of a few MW.

CCGT plants – in which the waste heat from the gas turbine is used again in a steam cycle for electricity production – are another option. This technology is suitable when electricity needs to be produced flexibly to meet demand requirements. At around 60 percent, the efficiency is lower than that of CHP (over 80 percent), but the value of the product (electricity) is higher than that of CHP (heat and electricity), so it is not possible to make general statements as to whether CHP or CCGT uses energy better.<sup>4</sup> It is also technically possible to use part of the steam from the steam cycle for heating purposes (decoupling) while using the remainder for electricity generation.

Pure gas turbine power plants, on the other hand, do not use waste heat. For plants with very few operating hours – such as reserve power plants – the simple gas turbine is ideal. Although the efficiency of around 40 percent is significantly lower because the waste heat remains unused, the installation of a steam circuit or other waste heat utilization would be neither practical nor economical in view of the few operating hours.

As this analysis examines technologies that can make a substantial additional contribution to domestic electricity production in winter, we focus on market-active gas-fired power plants without heat extraction. Therefore, CHP and reserve power plants are not discussed further. The market-active gas-fired power plants are designed as CCGTs. Market-active gas-fired power plants are assumed to be designed as CCGTs because they have higher efficiency compared to pure gas turbines and because completely foregoing waste heat utilisation is assumed to only be

<sup>1</sup> News Service Confederation The portal of the Swiss government, 2022, Energy: Federal Council facilitates start of work on reserve power plant in Birr (AG)

<sup>2</sup> News Service Confederation The portal of the Swiss government, 2025, Five reserve power plants for the security of energy supply from 2026

<sup>3</sup> News Service Confederation The portal of the Swiss government, 2025, Ansaldo's gas turbine test bench is to be available as a reserve power plant from February 2027

<sup>4</sup> CHP usually have higher overall efficiencies (approx. 80 percent vs. approx. 60 percent for CCGT). however, "better energy utilisation" is not unambiguous because electricity has a higher value (exergy) than heat.

Depending on the valence factor applied between electricity and heat (depending on the heat temperature and the context of use, among other things), both CHP and CCG can be advantageous from an energy perspective.

permissible for reserve power plants (see Chapter 4.1.2).

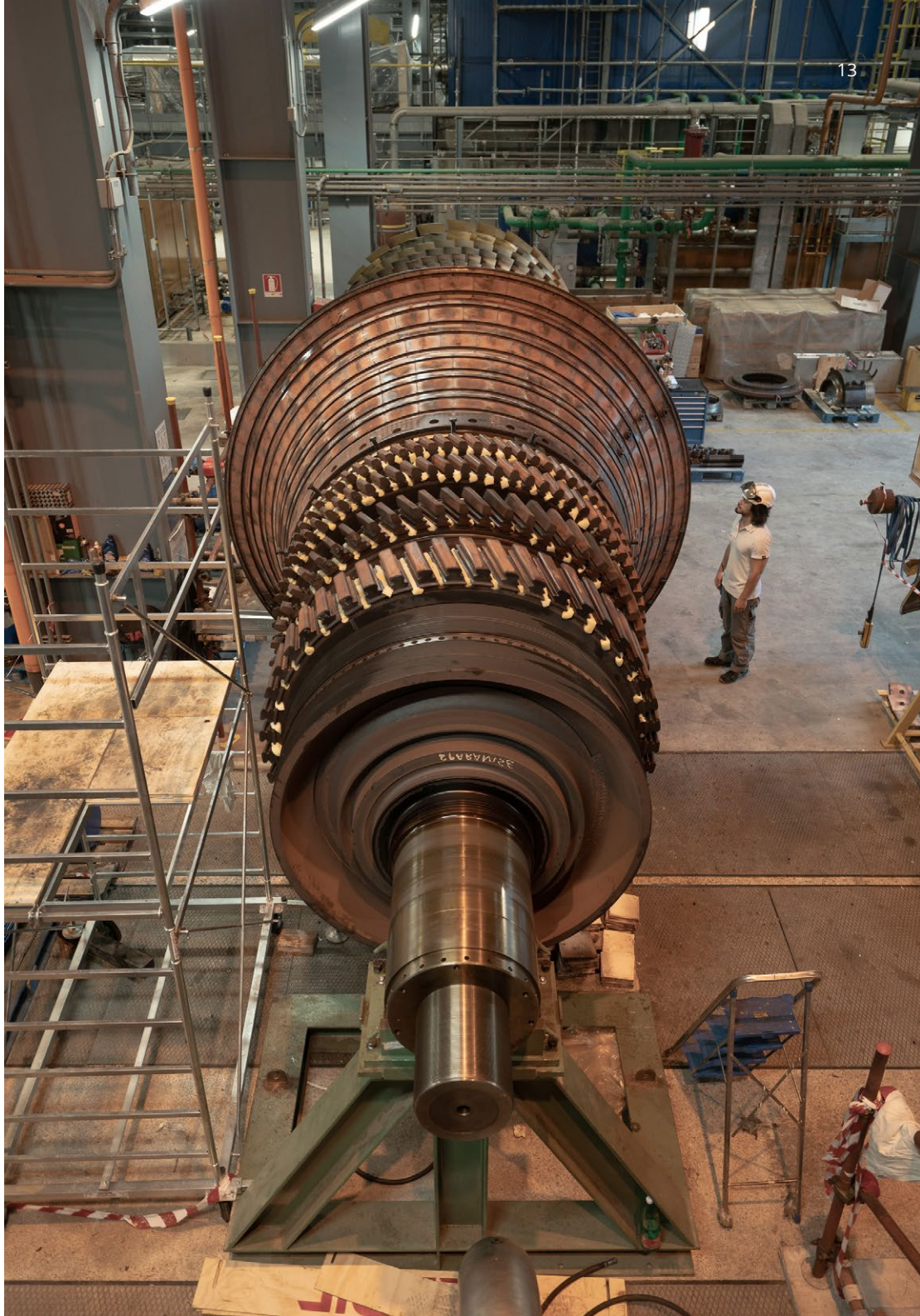
## 2.3

### Innovation

Both combined-cycle and simple gas turbines are already technically mature technologies. Innovations are focused primarily on fuels and "ready" concepts that allow gas-fired power plants to be prepared for future fuels or plant expansions, such as CO<sub>2</sub> capture. In this, we examine the fuels and solutions that enable low-emission operation of gas-fired power plants.

The analysis considers conventional operation and five low-emission variants:

- **Natural gas:** Conventional plant in which imported fossil methane is burned;
- **Renewable methane:** Incineration of biogas (partially processed or converted into biomethane) or synthetic renewable methane;
- **Natural gas + CDR:** Combustion of imported natural gas and covering the associated emissions with carbon Dioxide removal certificates (CDRs) of negative emission technologies (NETs);
- **Natural gas + CCS:** Incineration of imported natural gas, capture and permanent storage of the emitted CO<sub>2</sub>;
- **Hydrogen:** Combustion of renewable hydrogen, produced domestically or imported
- **Renewable liquid fuels:** Combustion of biogenic or synthetic liquid fuel, either domestically produced or imported.



Comparing fuels and other low-emission solutions using different dimensions

	Natural gas	Renewable methane	Natural gas + CDR	Natural gas + CCS	Hydrogen	Renewables Liquid fuels
Description	Combustion of imported natural gas	Combustion of biogas or synthetic renewable methane, either produced domestically or imported	Combustion of natural gas and covering the associated emissions with CDR certificates from NET	Combustion of natural gas, capture and long-term storage of the emitted CO <sub>2</sub>	Combustion of renewable hydrogen, produced domestically or imported	Combustion of biogenic or synthetic liquid fuel or other renewable liquid fuels, domestically produced or imported
Limiting greenhouse gas emissions	<p>●●●●</p> <p>High emissions (approx. 0.3 tonnes/MWh emitted without removal measures)</p>	<p>●●●●</p> <p>Biogas and synthetic methane produced with renewable hydrogen are recognised as low-emission fuels</p>	<p>●●●●</p> <p>CDR recognised as low emission (in the voluntary market); geographically decoupled from emissions; relatively higher public recognition for BECCS and DACCS, lower for other CDR opportunities</p>	<p>●●●●</p> <p>Parts of emissions not covered due to &lt;100 percent capture efficiency and emissions during CO<sub>2</sub> transport and storage. Must be combined with other solutions such as CDR for low-emission operation</p>	<p>●●●●</p> <p>Hydrogen from electrolysis with renewable electricity is recognised as a low-emission fuel</p>	<p>●●●●</p> <p>Biogenic or synthetic liquid fuels using renewable H<sub>2</sub> and atmospheric or biogenic CO<sub>2</sub> are recognised as low-emission fuels</p>
Technology maturity	<p>●●●●</p>	<p>●●●●</p> <p>Partial upgrading of biogas and upgrading of biogas to biomethane commercially available, synthetic methane production from renewable hydrogen in pre-commercial phase</p>	<p>●●●●</p> <p>First large-scale CDR projects under construction (BECCS), new technologies (e.g. DACCS, enhanced rock weathering) in demonstration phase</p>	<p>●●●●</p> <p>CO<sub>2</sub> separation, transport and storage technologies deployed on an industrial scale</p>	<p>●●●●</p> <p>Hydrogen production in early commercial phase, transport technologies in demonstration stage, no proven large-scale storage technologies. So far, no power plant-sized turbine has been tested with pure hydrogen.</p>	<p>●●●●</p> <p>Biofuel production in commercial phase, synthetic fuel production in pre-commercial phase, proven transport and storage technologies, proven combustion technologies</p>

●●●● very low ●●●● low ●●●● medium ●●●● high ●●●● very high

Comparing fuels and other low-emission solutions using different dimensions (continued)

	Natural gas	Renewable methane	Natural gas + CDR	Natural gas + CCS	Hydrogen	Renewables Liquid fuels
Availability	<p>●●●●</p> <p>Methane market globalised with LNG, high confirmed reserves</p>	<p>●●●●</p> <p>Limited biogas potential in CH/EU, synthetic renewable methane dependent on the availability of hydrogen and biogenic CO<sub>2</sub></p>	<p>●●●●</p> <p>CDR market in development with very limited availability. From 2040 Competition between BECCS/DACCS and CO<sub>2</sub>use for synthetic fuels. CO<sub>2</sub> geological storage capacity worldwide.</p>	<p>●●●●</p> <p>CO<sub>2</sub> storage capacity to prove worldwide</p>	<p>●●●●</p> <p>Swiss H<sub>2</sub> supply is expected to be imported for the most part. EU project pipeline for H<sub>2</sub> production faces major uncertainties, H<sub>2</sub> imports into the EU are subject to global competition</p>	<p>●●●●</p> <p>Potential for biogenic fuels limited by bioresources, availability of synthetic fuels dependent on availability of H<sub>2</sub> and CO<sub>2</sub>. Will probably become a global market as it is easy to transport.</p>
Transport	<p>●●●●</p> <p>Infrastructure already in place</p>	<p>●●●●</p> <p>Physical infrastructure already in place. Imported biogas in Switzerland is only recognised as low-emission under certain conditions (including state agreements).</p>	<p>●●●●</p> <p>BECCS and DACCS require CO<sub>2</sub> transport and storage infrastructure. First implementations in hubs (not in Switzerland).</p>	<p>●●●●</p> <p>CO<sub>2</sub> transport infrastructure from the power plant in Switzerland to geological storage is required. Only pipeline an option due to large volumes. No public planning in Switzerland before 2035. Dependence on European infrastructure.</p>	<p>●●●●</p> <p>H<sub>2</sub> transport infrastructure to power plant in Switzerland required. Only pipeline an option due to large volumes. No public planning in Switzerland before 2035. Dependence on European infrastructure.</p>	<p>●●●●</p> <p>Pipeline infrastructure required for large quantities, otherwise transport by rail theoretically possible.</p>
Swiss fuel storage	<p>●●●●</p> <p>No large domestic capacities available – Switzerland currently relies on bilateral agreements with neighbouring countries for additions to their underground storage systems. Research into potential storage sites is underway in Switzerland.</p>	<p>●●●●</p> <p>Like natural gas.</p>	<p>●●●●</p> <p>Like natural gas.</p>	<p>●●●●</p> <p>Like natural gas.</p>	<p>●●●●</p> <p>Similar to natural gas; H<sub>2</sub> but more difficult to store than natural gas: Compressed H<sub>2</sub> (350–700 bar) requires robust and capital-intensive infrastructure, liquid H<sub>2</sub> (–253 °C) causes high energy consumption and losses.</p>	<p>●●●●</p> <p>Liquid fuels can be easily stored in large tanks – Switzerland already stores oil products with a capacity of 7 million m<sup>3</sup>.</p>

Comparing fuels and other low-emission solutions across different dimensions (continued)

	Natural gas	Renewable methane	Natural gas + CDR	Natural gas + CCS	Hydrogen	Renewables Liquid fuels
Requirements on site	<p>●●●●</p> <p>Connection to high-pressure methane network is the only requirement</p>	<p>●●●●</p> <p>Connection to high-pressure methane network is the only requirement</p>	<p>●●●●</p> <p>Connection to high-pressure methane network is the only requirement</p>	<p>●●●●</p> <p>Connection to CO<sub>2</sub> downstream pipeline and additional space required for CO<sub>2</sub> capture systems</p>	<p>●●●●</p> <p>Connection to H<sub>2</sub> upstream pipeline required</p>	<p>●●●●</p> <p>Connection to fuel upstream infrastructure required</p>
Operation	<p>●●●●</p> <p>No restrictions in operation</p>	<p>●●●●</p> <p>No restrictions in operation</p>	<p>●●●●</p> <p>No restrictions in operation</p>	<p>●●●●</p> <p>Reduction of around 30 percent in electricity generation due to the energy consumption of the CO<sub>2</sub> capture plant. Chemical separation process restricts load change speed and therefore limits use of the system for peak loads.</p>	<p>●●●●</p> <p>No restrictions in operation</p>	<p>●●●●</p> <p>No restrictions in operation</p>

**Table 1:** Comparison of fuels and other low-emission solutions by limiting greenhouse gas emissions, technological maturity, availability, transportation, storage in Switzerland, local requirements and operation

Today, fossil **natural gas** is the dominant fuel for European gas-fired power plants. Natural gas is purchased on the wholesale market and delivered to the power plants via the existing pipeline network. Emission certificates must be purchased for every tonne of CO<sub>2</sub> emitted. In addition, the Swiss CO<sub>2</sub> levy is payable for imported fossil natural gas (see section 4. Legal and regulatory matters). As of 2026, Switzerland does not have any large scale gas storage facilities with TWh-level volumes (see Chapter 2.5).

As Switzerland has committed to achieving climate neutrality by 2050, gas-fired power plants fuelled by natural gas and without a climate-neutral solution would not be permitted. Various options for low-emission operation are therefore being considered.

One solution is **renewable methane** (biogas or synthetic, renewable methane). In regulatory terms, biogas is defined as “methaneric gas from the fermentation or gasification of biomass, including sewage gas and landfill

gas”.<sup>5</sup> The feed-in of biogas is subject to quality requirements of the gas industry: For example, after being processed into biomethane, it can be fed into the gas network without adaptation, while partially processed biogas may only be added as a quantity-controlled additive gas. For simplicity, we use the term biogas below as an umbrella term for partially processed biogas and biomethane. Biogas is commercially available, but has very limited potential in Switzerland and demand for it is also expected to rise, from the decarbonisation of heating and transport. Further volumes could be provided by synthetic methane produced from renewable hydrogen and biogenic CO<sub>2</sub> in power-to-gas plants; however, these are still in the pre-commercialisation phase and suffer from high acquisition, electricity and CO<sub>2</sub> input costs.

Natural gas can be replaced by Swiss biogas on the balance sheet with guarantees of origin. Technically, nothing will change with regard to the operation of the power plant. For foreign biogas, however, Switzerland does

not yet recognise certificates of origin. Bilateral agreements are required for foreign biogas to be recognised, and corresponding talks with the EU are underway. Today, importers must apply for international certificates for crediting from the Federal Office for the Environment (FOEN), whereby the exporting state must also recognise a transfer of the CO<sub>2</sub> reduction performance (part of the bilateral agreements)<sup>6</sup>. Unlike Switzerland, the EU does not regulate CO<sub>2</sub> reduction services by means of guarantees of origin – as these can only be used for the voluntary market – but through Proof of Sustainability (PoS) certificates. These PoS certificates do not follow the accounting book and claim approach <sup>7</sup> of guarantees of origin, but are also transmitted on a mass basis for gas trading and would have to be transferred to the Swiss Guarantees of Origin Register when imported into Switzerland.

Overall, renewable methane is the simplest technical solution for operating gas-fired power plants with the existing pipeline infra-

structure and commercially available technologies (turbine, peripherals). However, this solution is offset by high fuel prices and very limited fuel quantities.

Another solution is not to avoid CO<sub>2</sub> emissions from gas combustion, but to remove them elsewhere. To this end, the operator buys **“Carbon Dioxide Removal” (CDR) certificates**, for example from negative emission technology projects (NETs) such as bioenergy with CO<sub>2</sub> capture and storage (BECCS), direct air separation (DACCS), biochar or enhanced rock weathering (cf. KIG) . Unlike conventional offsetting programmes, NETs are based on the permanent removal and storage of biogenic or atmospheric carbon and are considered a necessary complementary measure in all net zero scenarios. Such certificates are currently scarce and very expensive. From the 2030s onwards, allowances are to be integrated into the EU emissions trading system.

NET allows a power plant to be operated with low emissions without requiring adjustments

<sup>5</sup> Art. 2 Mineral Oil Tax Act (MinöStG) and Art. 19a Mineral Oil Tax Ordinance (MinöStV)

<sup>6</sup> Reference to chapter 4.1.1.

<sup>7</sup> Book and slogan: The proof of sustainability is posted virtually and is decoupled from the physical supply of the energy source.

to its operation and location. The place of emission can be separated from the plant's location. For example, operators of gas-fired power plants could purchase CDR certificates from Nordic countries that already have connections to a CO<sub>2</sub> storage facility. This would make it possible to dispense with the development of a dedicated CO<sub>2</sub> infrastructure in Switzerland. By contrast, CDR projects in Switzerland would require new infrastructure – most likely pipelines connecting the most important emitters with the future European CO<sub>2</sub> network. Swiss CDR certificates are likely to be more widely accepted than foreign certificates. Because CDR is often confused with traditional offset certificates, the negative reputation associated with questionable offset programmes continues to have an impact to this day.

### Focus: CDR and NET

#### Definition

Negative emission technologies (NETs) are biological or technical processes that aim to remove **atmospheric CO<sub>2</sub>** and permanently bind it in forests, soils, wood products or other carbon sinks (definition in the Swiss Climate and Innovation Act). NET differs from CO<sub>2</sub> offsetting, which aims to reduce (rather than remove) **current and future CO<sub>2</sub> emissions**.

NET project operators generate CDR certificates, which can be purchased by the parties on a voluntary basis to reduce residual emissions. Several reference methods have been defined and are regularly updated in order to certify the projects. NET technologies are recognised by the Intergovernmental Panel on Climate Change as a necessary contribution to global climate neutrality.

#### Overview of the most important CDRs

- **BECCS** (Bio-Energy Carbon Capture and Storage) refers to the capture of CO<sub>2</sub> emissions from biomass processing plants (biomethane plants, wood-fired power plants, etc.) and their permanent storage in geological storage capacities (expected in Europe, especially in the North Sea). BECCS technologies reach a cost of less than 250 CHF / t under optimal conditions (large-scale biomass plants in the immediate vicinity of geological storage). The infrastructure required to transport the CO<sub>2</sub> from the emitter to the storage facility is a major limiting factor in most projects.
- **DACCS** (Direct Air Carbon Capture and Storage) refers to the direct capture of CO<sub>2</sub> from the atmosphere and its permanent storage in geological storage capacities. DACCS are typically built in locations with low energy costs and nearby storage facilities. Due to the very low CO<sub>2</sub> density in the atmosphere –

around 375 times lower than in the flue gas of a gas plant – DACCS is a very energy-intensive process that leads to high overall costs (500–800 Swiss francs per tonne).

- **Biochar** refers to the production of charcoal from biomass by pyrolysis and its application in soils or in durable materials (e.g. cement). There is no scientific consensus yet on the effects of biochar on soil balance and the lifetime of CO<sub>2</sub> sequestration.
- **Enhanced rock weathering** refers to the process of spreading rocks such as basalt onto land or into the ocean. These rocks react chemically with CO<sub>2</sub>. The CO<sub>2</sub> is converted into solid minerals and stored permanently in the rock. This solution eliminates the need for CO<sub>2</sub> infrastructure. The technology is still very young and there is limited scientific literature to quantify the sequestration of CO<sub>2</sub>.

- **Reforestation**, improved forest management and bog / wetland restoration are all about increasing the amount of biomass carbon sinks and thus increasing the amount of CO<sub>2</sub> separated and sequestered. Although this approach is by far the cheapest NET (<50 CHF / t), it has recently suffered from cases of poor CO<sub>2</sub> accounting, which has significantly damaged the credibility of the market.

#### CDR and NET in Switzerland

CDRs, also known as negative emissions technologies (NETs), can receive receivables from the KIG for innovative projects.<sup>8</sup> The Swiss Energy Strategy envisages that around 12 MtCO<sub>2</sub> per year of residual emissions will have to be removed by NET from 2050, of which up to 7 MtCO<sub>2</sub> per year are to be captured in Switzerland (SFOE Energy Perspectives 2050+).

The Federal Office for the Environment (FOEN) and the Swiss Association of Waste Incineration Plants have reached an agreement to implement an initial BECCS project of more than 100 ktCO<sub>2</sub> per year by 2030. Several smaller initiatives are running in parallel. For example, the Werdhölzli project in Zurich aims to remove 25 ktCO<sub>2</sub> per annum by 2030. The corresponding certificates are purchased by the City of Zurich. Several other similar projects could be realised in the next 10 years, accelerated by federal subsidy (Art. 6 KIG, 1.2 billion Swiss francs between 2025 and 2030). As the most important CO<sub>2</sub> storage sites are far away, BECCS projects in Switzerland will be more expensive than in Northern Europe. For projects over 100 ktCO<sub>2</sub> / a, we expect costs of between 300 and 400 CHF / tCO<sub>2</sub> according to initial studies.

#### CDR, voluntary and compliance markets

Currently, CDR certificates are not recognised in the ETS mechanism in either Europe or Switzerland.

The EU Regulation on Carbon Removal and Carbon Farming Certification, published in 2024, will establish the first EU-wide voluntary framework for CDR certification. This framework also provides for a European register to be set up by December 2028. In addition, the European Commission is to publish a report to Parliament and the Council by July 2026 on the possibility of integrating CDR into the EU ETS.

Instead of removing emissions externally, the CO<sub>2</sub> can be directly separated from the exhaust gas on site, compressed (or liquefied) and placed in geological deposits after the natural gas has been burned – the concept of **Carbon Capture and Storage (CCS)**. While capture technology is industrially proven, Switzerland lacks large-scale, long-term storage options. In the future, CO<sub>2</sub> captured in Switzerland is to be stored in other European countries. For the amount of CO<sub>2</sub> emitted by a gas-fired power plant, the captured CO<sub>2</sub> would probably have to be transported directly via pipelines to storage fields abroad. The domestic CO<sub>2</sub> pipeline network required for this could not be available until 2040 at the earliest. There are no specific national expansion plans yet in place in Switzerland (see Focus: CO<sub>2</sub> pipeline infrastructures).

In principle, CCS can be retrofitted to both CCGTs and simple gas turbines. However, CCS is rarely economical for simple gas turbines due to their typically low operating hours. It can also reduce the start-up speed of the gas turbine, making make flexible use more difficult. Many project planners are now defining "CCS-ready" criteria for subsequent

<sup>8</sup> Federal Office for the Environment FOEN, 2025, Fact sheet CO<sub>2</sub> capture, removal and storage: overview of the legal framework

## Focus: CO<sub>2</sub> infrastructure

There is currently no national CO<sub>2</sub> infrastructure in Switzerland. For example, there are currently no systems for capturing CO<sub>2</sub> from industrial processes or power plants in commercial operation<sup>9</sup>. In the future, CO<sub>2</sub> captured in Switzerland will need to be stored in other European countries. Similarly to hydrogen, there are considerations for a European CO<sub>2</sub> pipeline infrastructure to connect important CO<sub>2</sub> sources and suitable sinks. The European Commission mission estimates that Europe will need a CO<sub>2</sub> pipeline network of 15,000 to 19,000 km by 2050, with a budget of € 9.3 billion to € 23.1 billion<sup>10</sup>. By way of comparison, the transmission grid for natural gas is 200,000 km long. Among European countries, the Netherlands is currently the most advanced: it has already awarded the contract for the construction of a 55 km pipeline to the port of Rotterdam.

At the end of 2024, the FOEN and SFOE presented a CCS /NET roadmap outlining the vision for a complete pipeline network that connects domestic CO<sub>2</sub> sources with foreign storage fields. Planning for the Basel-Zurich-Trasse in particular is currently being advanced, as cement plants and waste incineration are the largest emission clusters there. However, there are still no legally binding regulations for a national CO<sub>2</sub> infrastructure: At the beginning of 2025, Parliament therefore referred a postulate (24,4256) obliging the Federal Council to submit a draft law on the construction, operation and pricing of CO<sub>2</sub> pipelines and storage for consultation by 2026. Alternatively, CO<sub>2</sub> can also be transported by lorry, rail or ship, but this is not practical for the volumes associated with larger power plants.

retrofitting. In a new build projects, this typically means reserving sufficient space for the separation unit, pipes, and vapour extraction points, providing cooling water and power connections, and designing the layout so that flue gas ducts can be rerouted later without major conversion work. While such provisions can be realised at a moderate additional cost, a later retrofit can be very expensive or, in individual cases, practically impossible because essential infrastructure would have to be rebuilt or relocated.

CCS can be used to capture around 90 percent of flue gas emissions. Nevertheless, unavoidable residual emissions remain from the operation of the gas-fired power plants. To fully offset these, additional compensation measures such as CDR certificates must be used.

Renewable **hydrogen** does not cause any emissions when burned in gas-fired power plants. Manufacturers already offer “H<sub>2</sub>-ready” systems that can withstand up to 30 percent by volume of hydrogen in the natural gas mixture and can be retrofitted to 100 percent H<sub>2</sub> in the future – however, large-scale

demonstrations are still pending. According to the Federal Office of Energy (SFOE), hydrogen production through electrolysis in Switzerland is likely to remain limited due to the economic framework conditions. Switzerland will therefore be dependent on imports. Hydrogen supply in Europe is also likely to be largely dependent on the global market, as shown by the increase in international agreements (e.g. Germany-Canada, EU-Australia) and infrastructure projects (e.g. SouthH<sub>2</sub> between Algeria and Europe). As power plants require large quantities of hydrogen, a supply via pipelines is probably the only realistic option from a technical point of view. The SFOE does not expect the hydrogen network to be expanded before 2035; the development depends heavily on the progress of the European Hydrogen Backbone Infrastructure (see Focus: Hydrogen infrastructure).

<sup>9</sup> With the exception of a few small biogas feed-in plants, where the CO<sub>2</sub> captured during biogas upgrading is local, for example in recycled concrete or in the production of sparkling water.

<sup>10</sup> European Commission, 2024, CO<sub>2</sub> transport infrastructure: key to achieving climate neutrality by 2050

## Focus: Hydrogen infrastructure

Switzerland currently does not have any hydrogen pipelines. Without a corresponding pipeline infrastructure, it is not feasible to operate gas-fired power plants with hydrogen. Today, Hydrogen is transported from production sites to customers in compressed gas containers, which is feasible for smaller customers, but by no means for larger power plants. In the future, the supply is expected to be provided via a European "hydrogen backbone", which is to be developed by a large number of European transmission system operators – including the Swiss companies fluxSwiss and the Swiss Gas Energy Association (VSG) – with the aim to complete it by 2040. The backbone combines new pipelines with upgraded natural gas pipelines and is also to run through Switzerland: It is envisaged that one of the two transit gas tubes (northern line Basel–Griespass) will be fully 100 percent H<sub>2</sub>, while the parallel tube continues to transport natural gas. The hydrogen grid con-

nection for gas-fired power plants in Switzerland depends crucially on if, and when, the European backbone is realised and whether capacities can be secured at the large storage facilities close to the border. There is currently no expansion plan for a Swiss hydrogen infrastructure; the existing hydrogen strategy<sup>11</sup> does not yet contain any binding grid plans. European-wide expansion of the hydrogen network is also still subject to considerable uncertainty.

In addition to green hydrogen from renewable energies, other low-emission variants could also play a role in the future. These include blue hydrogen (methane reforming with CCS), pink hydrogen (electrolysis with nuclear power) and white hydrogen (geological origin – but currently without proven reserves). As of 2026, Switzerland has no large (TWh volume) hydrogen storage facilities (see Chapter 2.5).

**Renewable liquid fuels** are produced from biogenic sources (biofuels: Biomethanol, biodiesel) or synthetically produced from renewable hydrogen and biogenic or atmospheric CO<sub>2</sub> / N<sub>2</sub> (e-fuels: e-methanol, e-diesel, e-ammonia). The available fuels also include hydrogenated vegetable oils (hydrotreated vegetable oil (HVO)). However, the potential of biofuels is restricted by the limited availability of sustainable biomass. The costs of producing e-fuels, which largely depend on the price of renewable hydrogen, are significant-

ly higher than for conventional fuels. Their potential also depends heavily on global hydrogen production.

These liquid fuels can be transported worldwide by ship. However, liquid fuels require large storage tanks to operate power plants. For example, for storing diesel for full-load operation of a gas-fired power plant over 10 weeks (assumptions CCGT with 500 MW, 60 percent efficiency) approx. 140,000 m<sup>3</sup> of storage would be required. Liquid fuels can generally be used in existing diesel combustion chambers without fundamental modifications. Gas-fired power plants can use these fuels today via standard dual-fuel injection systems. With appropriately modified burners, they can also run on e-methanol. Because liquid fuels can be stored in large quantities close to the power plants, strategic reserve power plants in Switzerland should be designed as dual-fuel plants (natural gas and liquid fuels) to ensure energy supply security.

<sup>11</sup> Der Bundesrat, 2024, Hydrogen Strategy for Switzerland

## 2.4

### Suitable sites

In Switzerland, the number and size of industrial sites with good connections to the electricity and gas grids is limited. Other criteria such as proximity to residential areas also limit the possibilities.

An initial analysis identified potential sites for gas-fired power plants in the cantons of Aargau, Lucerne, Solothurn, Neuchâtel, Vaud and Valais. This analysis took into account the criteria of electricity grid connection, natural gas grid connection, other infrastructure, suitable zones and cantonal legislation.

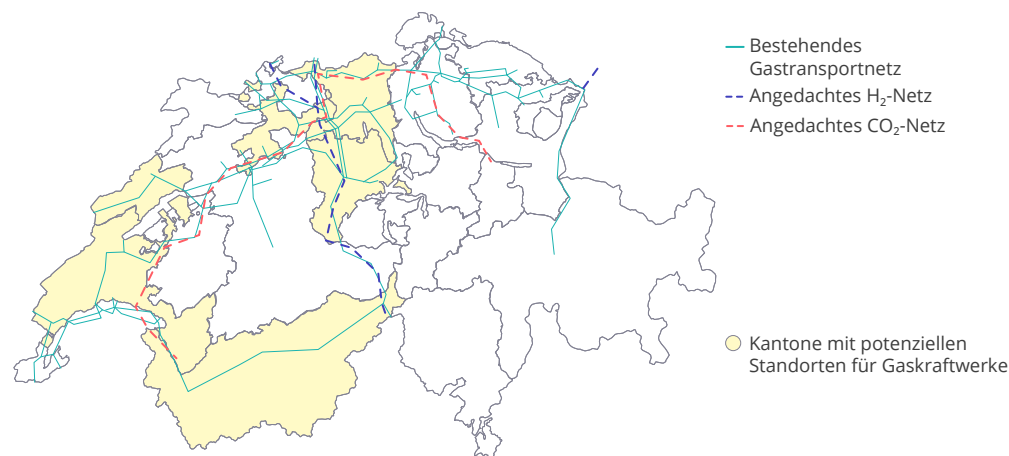
The options for hydrogen and CO<sub>2</sub> infrastructure were also considered. Based on the current planning assumptions, only a few locations are suitable for solutions with hydrogen or CCS, as they must be located within a maximum of 5 km away from the envisaged infrastructure.

In addition to the above criteria, cantonal legislation is also taken into account (see Chapter 4. Corporate law and regulation).

**Electricity grid connection:** From a connected load of 100 MW, a gas-fired power plant generally requires a connection to the extra-high voltage grid (grid level 1; see Swissgrid “Policy on power plant connections and grid utilisation” (RKK)). Even if a connection to distribution grids at grid level 3 would be technically feasible, the requirement for grid level 1 is intended to prevent bottlenecks in regional distribution grids and ensure unrestricted grid access to power and ancillary services. In addition, the transmission grid at the connection point must be capable of dissipating energy from this point.

**Natural gas grid connection:** The gas infrastructure required depends on the installed capacity of the power plant. From approximately 100 MW of output, gas-fired power plants generally require a direct connection to the Swiss high-pressure network operated by

### Schematic Overview of the Development of Hydrogen and CO<sub>2</sub> Infrastructure in Switzerland



**Figure 2:** Schematic overview of the planned development of the first hydrogen and CO<sub>2</sub> pipeline sections in Switzerland compared to the existing natural gas transport network<sup>12, 13, 14</sup>. However, the possible course of the CO<sub>2</sub> pipelines in particular is still very unclear at present (only the trunk line is shown in the illustration)<sup>14</sup>. Some sections of the planned CO<sub>2</sub> infrastructure shown here appear problematic and require further clarification.

Swissgas, regional network operators, or transit gas system (55–70 bar). At this scale, the amount of fuel required exceeds the capacity

of the lower-pressure distribution networks (5–16 bar) and the power plant also requires higher pressures in the fuel supply.

<sup>12</sup> Swissgas, 2026, network map

<sup>13</sup> H2, 2026, Hydrogen Infrastructure Map

<sup>14</sup> Aramis – SFOE, DDPSA, 2021, CO<sub>2</sub>NET – Rough design and cost estimate for a CO<sub>2</sub> collection network in Switzerland

The availability of natural gas via the transit gas pipeline from Germany and France is quite high, at a total of 26 billion standard cubic metres<sup>15</sup> per year. As an example, a large CCGT with an electrical output of 500 MW would require a maximum of 2.5 percent of this capacity (assuming electrical efficiency of 60 percent).

#### Further infrastructure and suitable zones:

Further criteria must be introduced for the local suitability of the locations. A connection to harbours, railway lines and roads is a prerequisite for the logistics of building and operating power plants. Industrial areas also offer planning advantages for power plants, as they generally have the necessary infrastructure and easier authorisation requirements. Finally, aspects such as priority of use and protection as well as protection zones at regional and local level are important to avoid conflicts with other agricultural or urban uses and to ensure that the plants comply with local planning guidelines and environmental regulations.

#### Outlook for hydrogen and CO<sub>2</sub> infrastructure:

When building a hydrogen power plant, a connection to hydrogen pipelines at Swiss and European level is required. Similarly, for power plants with CO<sub>2</sub> capture, connection to a CO<sub>2</sub> transport and export infrastructure is a prerequisite. There are no concrete national expansion plans for such infrastructures to date. Domestic hydrogen and CO<sub>2</sub> pipeline networks could be available by 2040 at the earliest. Industry associations have drawn up initial conceptual layouts for these infrastructures. In view of the major infrastructure expansion challenges in Switzerland, it is likely that hydrogen and CO<sub>2</sub> pipelines will follow the route of the existing natural gas pipelines. According to the European Hydrogen Backbone, the Swiss route will connect northern and southern Europe along the Swissgas pipeline. For CO<sub>2</sub> transport, an initial route linking the Basel and Zurich hubs is being considered, with a possible connection to the European grids near Basel or via shipping on the Rhine. Other ideas include the reuse of disused oil pipelines in Valais and Grau-



<sup>15</sup> A standard cubic metre (Nm<sup>3</sup>) is a volume measure for gases in relation to fixed standard conditions. It indicates the volume of a gas at these reference conditions.

bünden toward northern Italy. However, the possible course of CO<sub>2</sub> pipelines in Switzerland is still very unclear at present. The European CO<sub>2</sub> pipeline network does not yet exist.

**Storage options for natural gas and hydrogen**

	Aquifer	Salt caverns	Rock caverns	Liquefied	Spherical and cylindrical bearing
Typical storage volume (m Nm <sup>3</sup> )	1000	60	25	90	<1
Pressure (bar)	80–150	250	230–300	–	60
Storage cycles per year	1	1–4	6–12	–	–
Construction time (years)	>10	10–25	5	–	–
Costs	Low	Low (0.1–0.5 CHF /kWh)	Medium (additional sealing required)	High	High (CHF 10–40 /kWh)
Technical maturity for natural gas /hydrogen	High /Low	High / Low	Medium / Low	High / Medium	High / High
Potential for gas storage in Switzerland	No potential	Project idea Saline. Rough estimate of potential at 1–2 TWh <sup>16</sup>	Current GAZNAT project in Oberwald. Project potential there 1.48 TWh (4% of Switzerland’s annual gas consumption). Overall potential is much greater. Preliminary studies only, earliest availability 2030.	The idea of LNG in Schweizerhalle and gravel pit on the transit line was abandoned. Not very realistic on a large scale without a seaport.	Available potential in Switzerland, but not suitable for seasonal storage.

Preparatory meetings for the gas storage symposium at Swisstopo, 2025

**Table 2:** Overview of the storage options for natural gas and hydrogen and their potential for Switzerland.

<sup>16</sup> Basel Landschaft, 2024, submission to the District Council

## 2.5

### Gas storage

Switzerland has a gas distribution infrastructure, but unlike countries such as Germany, Italy and France, it lacks both gas storage facilities and liquefied natural gas (LNG) terminals (due to the lack of deep-sea ports). In the absence of domestic production, this limits energy supply security.

The current solution is to use dual-fuel systems, which are common in industrial gas applications in Switzerland. The operational readiness of gas-fired power plants can be ensured through the provision of liquid fuels. If a power plant cannot be built directly next to a large tank farm, a railway connection with an unloading station would be required in addition to several days' worth of on-site fuel storage. The mandatory stocks are currently 1.2 million m<sup>3</sup> for diesel oil, and 1.4 million m<sup>3</sup> for extra light heating oil (of which 0.38 million m<sup>3</sup> is allocated for dual-fuel systems), with effective stocks generally higher. Storage of diesel for gas-fired power plants

– assuming a 500 MW CCGT operating at 60 percent efficiency for 10 weeks at full load – amounts to an additional approximately 0.14 million m<sup>3</sup>. Liquid fuels can therefore technically be stored without any problems, without major energy losses, and in existing storage facilities. By 2050, the steady decline in demand for oil should mean that storage space will be almost completely available for renewable liquid fuels.

Another solution that is already in practice is the use of foreign gas storage facilities. In Europe, several countries – including France, Germany and Austria – have geological storage facilities (specifically, depleted gas fields and salt caverns) with a total capacity of around 30 percent of Europe's annual gas consumption. An agreement with France currently gives Swiss suppliers Gaznat and Gasverbund Mittelland non-discriminatory access to French storage facilities, although only for contractually agreed quantities – amounting to around 7.5 percent of annual Swiss natural gas consumption. If access to gas volumes stored abroad can be secured in

a politically robust manner by means of an international treaty, additional storage volumes in Germany, Italy or France could be leased on a long-term basis or secured via shareholdings. German operators of large storage facilities are currently even considering shutting down capacities due to a lack of seasonal bookings. Purchasing storage capacities abroad could therefore be the most cost-effective way for Switzerland to establish a strategic gas storage position. The two new "Regulations on solidarity measures in the event of a gas shortage" (as part of agreements with Germany and Italy), do not, however, grant Switzerland a guaranteed right of access to storage capacities. Instead, they should be understood primarily in the context of the joint utilisation of the transit gas pipeline.

Another possible solution would be new domestic gas storage facilities. Switzerland currently has no large-scale domestic storage options of its own. Together with universities and industry, the SFOE is investigating how large-scale methane storage could be real-

ised in Switzerland. Table 2 provides an overview of general options for the storage of natural gas and hydrogen, their potential, and specific project ideas for Switzerland.



# 03

## Acceptance

Low-emission solutions could increase social acceptance of gas-fired power plants

In Switzerland, gas-fired power plants have had little presence in the public debate to date. If power plants are discussed, the acceptance values in surveys are lower than all other production technologies – only electricity imports have an even lower acceptance rate.<sup>17</sup>

We assume that the respondents in these surveys are thinking of gas-fired power plants that are fuelled with fossil natural gas and therefore emit CO<sub>2</sub>. Gas-fired power plants with a low-emission solution could potentially have a higher level of social acceptance. Two examples underline this. On the one hand, the expansion of hydrogen enjoys moderate acceptance in the surveys, higher than, for example, the expansion of Alpine PV, reserve power plants or nuclear power plants. Secondly, the use of renewable fuels (such as hydrotreated vegetable oil (HVO) and e-methanol) in the reserve power plants has substantially improved which has helped with public acceptance.

However, acceptance will likely depend on which low-emission solution is chosen. Solutions using renewable methane, hydrogen or renewable liquid fuels are expected to achieve comparatively high acceptance levels. In contrast, for carbon dioxide removal (CDR), the credibility of the associated evidence would be decisive for social acceptance. It may therefore be important that the verifications and / or certificates are generated within Switzerland – either directly by Swiss companies (e.g. through their own biogas plants or negative emissions projects) or procured through close co-operative arrangements.



<sup>17</sup> gfs.bern, 2026, Security of energy supply and price stability remain key



# 04

## Law and regulation

For gas-fired power plants to contribute to Switzerland's energy supply security, the legal and regulatory framework needs to be adapted.

## In brief

- The current legal and regulatory framework is not geared towards market-active gas-fired power plants.
  - Two central control instruments are relevant for natural gas-fired power plants: EU Emissions Trading System (EU ETS) and CO<sub>2</sub> levy. The latter leads to a higher burden on gas-fired power plants in Switzerland compared to the surrounding European countries. A CO<sub>2</sub> levy is also payable for biogas (if imported via the gas grid) and CCS (even for the amount of CO<sub>2</sub> captured).
  - Gas-fired power plants are not prohibited at federal level or in the cantons considered. However, operating them on fossil natural gas runs counter to the federal and cantonal climate neutrality targets. In addition, energy legislation is generally in favour of a fully renewable energy supply and therefore promotes corresponding technologies. There is no other mechanism for the receivable of market-active gas-fired power plants.
  - The regulatory implications for waste heat utilisation when fossil fuels are used are unclear. In some of the cantons analysed, it cannot be ruled out that the remaining waste heat from the combined-cycle gas turbine (CCGT) plant would have to be purchased by a third party if operated with fossil natural gas. This requirement would represent a major hurdle for implementation.
- Necessary adjustments:
- Exemption of gas-fired power plants participating in the EU ETS from the CO<sub>2</sub> levy, therefore eliminating the current double charge and creating a level playing field with gas-fired power plants in the EU. Ensuring exemption from CO<sub>2</sub> levy when using biogas or CCS.
  - Establishing a subsidy scheme for gas-fired power plants, for example through a capacity market
  - Recognising the steam cycle of a CCGT plant as sufficient waste heat utilisation

## 4.1

### Current status

#### 4.1.1

#### ETS and CO<sub>2</sub> levy

Two separate control instruments apply to the burning of fossil fuels in a Swiss gas-fired power plant: firstly, the Swiss Emissions Trading System (ETS), which is linked to the EU ETS and through which CO<sub>2</sub> certificates must be purchased. This steering system is also used in the EU. Secondly, however, Switzerland also pays the national CO<sub>2</sub> levy, which is levied on every imported litre of heating oil or every kilowatt hour of natural gas. In the case of gas-fired power plants, this charge can only be partially reimbursed – and at present, in practice almost not at all – even when the plant participates in the ETS.

According to the Swiss CO<sub>2</sub> Act (Art. 16), operators of incineration plants must participate in the ETS as soon as their total heat input exceeds a certain threshold set by the Federal Council at 20 MW for all fossil or partially fossil fuels in Annex 6 of the CO<sub>2</sub> Ordinance (An-

nex 6 of the CO<sub>2</sub> Ordinance).<sup>18</sup> For a gas-fired power plant, annual emissions reports and the purchase of emission certificates would therefore be required.

At the same time, the federal government levies a CO<sub>2</sub> levy on the import of all fossil fuels. Since 2024, this charge has been set by the Federal Council at the statutory maximum of 120 Swiss francs per tonne. In principle, CO<sub>2</sub> levy could be reclaimed when the plant participates in the ETS. However, there is an explicit exception for gas-fired power plants: According to Article 17 of the CO<sub>2</sub> Act, a power plant operator can only reclaim this levy to the extent to which the joint burden of the CO<sub>2</sub> levy and emission allowances exceeds the “external costs of CO<sub>2</sub> emissions”. They are therefore subject to an administratively set minimum price. This is set annually by the FOEN; by the end of 2025, this was CHF 136.80 /t CO<sub>2</sub>.<sup>19, 20, 21</sup> With effect from 1 January 2026, the revision of the CO<sub>2</sub> Ordinance

of 19 November 2025 increased the external cost rate from CHF 136.8 /t CO<sub>2</sub> to CHF 430 /t CO<sub>2</sub>. The reimbursement of the CO<sub>2</sub> levy therefore only begins when the price of the ETS certificates rises to more than CHF 310 /tCO<sub>2</sub> (only then does the sum of ETS certificates and the CO<sub>2</sub> levy exceed the minimum price). As ETS prices at this level are not expected until 2050, this effectively results in a complete double burden from both emission allowances and CO<sub>2</sub> levy.

The calculation example in Table 3 illustrates the reimbursement of the CO<sub>2</sub> levy for up to the end of 2025 and from 2026 onwards:

From 2026, the final charge to the power plant operator in this example will be CHF 200 per tonne of CO<sub>2</sub>, as the sum of the CO<sub>2</sub> levy and the price of the ETS certificate is below the external costs and therefore no reimbursement will be made.

### Reimbursement of CO<sub>2</sub> levy

	Until end of 2025	Since 2026
<b>CO<sub>2</sub> levy</b>		CHF 120 /t CO <sub>2</sub>
<b>ETS certificate price (example)</b>		CHF 80 /t CO <sub>2</sub>
<b>External costs according to FOEN (EXK)</b>	CHF 136.8 /t CO <sub>2</sub>	CHF 430 /t CO <sub>2</sub>
<b>Combined initial load of the power plant operator (KIB)</b>	Payment CO <sub>2</sub> levy + ETS certificate price = CHF 200 /t CO <sub>2</sub>	
<b>Reimbursement to operator (= max [0, KIB-EXK])</b>	CHF 63.2 /t CO <sub>2</sub>	CHF 0 /t CO <sub>2</sub>
<b>Final burden on the power plant operator</b>	CHF 136.8 /t CO <sub>2</sub>	CHF 200 /t CO <sub>2</sub>

**Table 3:** Example calculation for the refund of the CO<sub>2</sub> levy

The double pricing – emission allowances plus (remaining) CO<sub>2</sub> levy – significantly increases the production costs of Swiss gas-fired power plants compared to their European counterparts, where typically only the emission allowance price is charged. This cre-

ates a structural cost disadvantage for operators, which reduces the competitiveness of gas-fired power plants in Switzerland and would have to be offset by additional subsidies (see Chapter 5).

<sup>18</sup> Federal Office for the Environment FOEN, 2025, webinar: Offsetting of pipeline-bound foreign renewable gas (22.5.2025)

<sup>19</sup> Federal Office for the Environment FOEN, 2025, CO<sub>2</sub> levy

<sup>20</sup> Federal Office for the Environment FOEN, 2025, Emissions trading system for plant operators

<sup>21</sup> Federal Office for Spatial Development ARE, 2020, External costs and benefits of transport in Switzerland; Section 3.5 Climate: Based on international studies on global prevention costs, from an average value of CHF 136.8 per tonne of CO<sub>2</sub>

According to Art. 15 para. 3 of the CO<sub>2</sub> Act and Art. 92c-f of the CO<sub>2</sub> Ordinance, renewable methane (biogas and synthetic renewable methane) and renewable hydrogen<sup>22</sup> can be counted as zero emissions in the ETS and thus reduce the obligation to purchase ETS certificates. Swiss certificates of origin are required for Swiss renewable methane (in accordance with Art. 92c CO<sub>2</sub> Ordinance). For imported renewable methane, recognition is only possible under certain conditions. Specifically, an internationally valid proof of origin or proof of sustainability must be available for each imported unit of renewable methane or renewable hydrogen, registered with the FOEN (Art. 4b CO<sub>2</sub> Ordinance), and traceable back to the production plant. For gas imported by pipeline, so-called pipeline-bound imports, the gas must be physically fed into the European pipeline network, among other things. Double counting in the country of origin must be ruled out by bilateral state agreements (Art. 10, Art. 92e CO<sub>2</sub> Ordinance).

However, the CO<sub>2</sub> levy for imported, grid-bound renewable methane is still payable today and, if used for a gas-fired power plant, can only be refunded if the CO<sub>2</sub> levy exceeds the external costs<sup>23</sup>. This means that there is effectively no refund. The Federal Government / Customs classifies pipeline gas as natural gas<sup>24</sup>, regardless of additional guarantees of origin or proof of sustainability. The CO<sub>2</sub> levy does not apply to renewable gas only if it is imported without using a pipeline (e.g. as bio-liquid natural gas (LNG) or e-methane delivered in containers). However, such container deliveries are not conceivable for market-active gas-fired power plants due to the quantities of gas required.

CCS can also be used to avoid emissions and reduce the corresponding ETS certificates. However, the CO<sub>2</sub> levy must still be paid. Here, too, there is effectively no refund.

### Collection and reimbursement ETS

	Renewable gases			Natural gas	
	Wired (virtual) import	Other import	Domestic production	Without CCS	With CCS
Collection of CO <sub>2</sub> levy Art. 29 of the CO <sub>2</sub> Act	Yes	No	No	Yes	Yes
Reimbursement CO <sub>2</sub> Charge pursuant to Art. 17 and Art. 31 of the CO <sub>2</sub> Act	Yes*	-	-	Yes*	Yes*
Eligibility for ETS or reduction obligation	Yes (Criteria: <a href="#">Art. 15</a> and <a href="#">Art. 31</a> of the CO <sub>2</sub> Act)	Yes	Yes	No	Yes (for intercepted part)
Cost components fossil-thermal power plant	Gas + GoO/ PoS + CO <sub>2</sub> levy*	Gas + GoO/ PoS	Gas + GoO	Gas + ETS+ CO <sub>2</sub> levy*	Gas + ETS (for non-intercepted part) + CO <sub>2</sub> levy*

\*For fossil-thermal power plants, the CO<sub>2</sub> levy is only partially reimbursed (or not actually reimbursed as of 2026)

**Table 4:** Overview ETS collection and reimbursement

<sup>22</sup> Hydrogen that meets the eligibility requirements in accordance with the CO<sub>2</sub> Ordinance.

<sup>23</sup> The same regulations for the reimbursement of the CO<sub>2</sub> levy apply to renewable methane as for natural gas. However, as no ETS certificates have to be procured for renewable methane, these are not included in the calculation for the refund.

<sup>24</sup> Customs assessment of goods upon import is based on "type, quantity and quality" at the time of customs declaration, see also Art. 19 of the Customs Act and Art. 3, Art. 19 of the MinöStG.

### 4.1.2 Other legal framework conditions at federal level

There are no federal-level provisions that prohibit the construction of thermal-fossil gas-fired power plants. However, the goal of climate neutrality at the federal level (net-zero target by 2050, KIG, 1 Jan. 2025) could be opposed to the construction of fossil power plants if climate-neutral operation cannot yet be guaranteed. In addition, energy legislation is generally in favour of a fully renewable energy supply; for example, only the expansion of renewable energies is deemed to be of national interest and only corresponding technologies are promoted. There is no other mechanism for receivable fossil capacity on the market. Gas-fired power plants are currently only planned as reserve power plants, for which the federal government has issued a corresponding invitation to tender.

This means that gas-fired power plants cannot currently rely on any subsidies to support their profitability. Additional challenges also exist. For example, there is no explicit entitlement under federal law to be connected to a gas grid.<sup>25</sup> There is an entitlement to access the gas grid (i.e. purchase by the grid) if this is technically possible and economically reasonable or the grid operator cannot put forward any objective reasons opposing access to the grid (cf. Art. 13 RLG and Art. 7 para. 2 lit. a KG)<sup>26</sup>. However, unlike in the electricity sector, grid access is not regulated – instead, it must be negotiated on a case-by-case basis.

With regard to the approval procedures, it can be assumed that the construction of a gas-fired power plant basically requires an entry in the structure plan (cf. Art. 8 (2) RPG), as projects with significant impacts on space and the environment require a basis in the structure plan.<sup>27</sup> This planning step extends the overall authorisation timeline.

The limit values for air pollution control (see LRV, Annex 2, No. 83 Emission limit value for gas turbines over 40 MW thermal) should not represent a relevant hurdle. They can be met with catalytic converter technology and are now standard for new CCGTs, but rarely for pure gas turbines.<sup>28</sup>

### 4.1.3 Other legal framework conditions at cantonal level

We are referring here only to the suitable cantons identified in Section 2.4: Aargau, Lucerne, Solothurn, Neuchâtel, Vaud and Valais.

There are also no explicit bans on gas-fired power plants at cantonal level in any of the areas analysed. Only the canton of Valais has the option of municipal bans. However, in its 2017 “Gas” sub-strategy, the Canton of Valais sees a possible need for gas-fired power plants.<sup>29</sup>

An important framework condition in the cantons analysed concerns the use of waste heat when fossil fuels are used. They specify that waste heat must either be used professionally and completely (LU, VD, VS), at least 75 percent (AG), largely (SO) or according to the state of the art (NE). It remains unclear how the utilisation of waste heat from a CCGT plant – specifically the use of gas turbine heat in a steam cycle – is assessed. For example, it is uncertain whether this would be considered to be fully, largely, or state of the art utilised. If not, the CCGTs envisaged in this project would not be possible in the cantons. The waste heat not utilised by the CCGT would have to be used by another consumer. Only decentralised CHP plants would be suitable for this, but not CCGTs. Pure gas turbines are unlikely to be realisable in Switzerland due to this legislation. If renewable fuels are used, all cantons analysed (except VD and SO) provide for simplified requirements regarding waste heat utilisation.

<sup>25</sup> Grid connection refers to the physical liability to the gas infrastructure.

<sup>26</sup> Grid access enables actual use; Fedlex the publication platform of federal law, 2025, Federal Act on Pipeline Systems for the Transport of Liquid or Gaseous Fuels

<sup>27</sup> Depending on the specific local conditions at the project site (e.g. pre-existing large degree of industrial use), exceptions are conceivable.

<sup>28</sup> Limits: CO 35 mg / m<sup>3</sup>; NOx 20 mg / m<sup>3</sup> (gaseous fuels); NOx 40 mg / m<sup>3</sup> (liquid fuels). A catalytic converter is required to comply with the Swiss NOx limit values.

Internationally, these catalytic converters are widely used in newer plants for combined-cycle power stations, but rarely for pure gas turbines.

<sup>29</sup> Canton of Valais, 2017, Strategy, efficiency and energy supply – “Gas” sub-strategy

In addition to federal requirements, several of the cantons analysed have additional requirements. These include an entry in the structure plan (LU), or and entry for installations that are subject to an environmental impact assessment, such as a gas-fired power plants (SO). Other cantons apply other spatially effective requirements such as a "utilisation plan" (AG, NE). The requirement for an entry in the structure plan is likely to add approximately 1–3 years to the overall authorisation timeline, with municipal utilisation planning taking a further 2–3 years. Federal legislation (Art. 10 para. 1 EnG), provides for the designation of priority areas only for hydropower, wind energy and solar technologies. There are also special authorisation requirements in AG (operating licence), VD (special authorisation, special authorisation procedure), NE (approval by Parliament with fak. Referendum).

#### 4.2

##### Necessary adjustments

The analysis shows that the current regulatory framework is not geared to market-active gas-fired power plants in several respects. A package of measures is required so that gas-fired power plants can contribute to Switzerland's energy supply security. The legal basis for this must first be created. The most important measures are described below.

Figure 3 illustrates a possible timetable for the implementation of the necessary adjustments and subsequent steps leading up to the commissioning of gas-fired power plants (commercial operating date (COD)).

##### Adjustment of regulatory requirements on waste heat utilisation

The requirements regarding waste heat utilisation must be designed and, if necessary, adapted in such a way that highly efficient gas-fired power plants can fulfil them sensibly. In principle, combined-cycle gas turbine (CCGT) operations should be considered sufficient heat utilisation. In view of the role of gas-fired power plants for Switzerland's ener-



gy supply security, a corresponding requirement at federal law level seems appropriate.<sup>30</sup> As part of these provisions, it could also

be ensured that gas-fired power plants comply with certain minimum requirements for heat utilisation. Alternatively, cantons with

<sup>30</sup> The basis for this could be the federal government's fundamental legislative competence in the area of the use of domestic energy and economical and rational energy consumption, as well as the federal government's explicit legislative competence in the area of of the energy consumption of plants, cf. Art. 89 para. 2 and para. 3 Federal Constitution

Schedule of a new gas-fired power plant

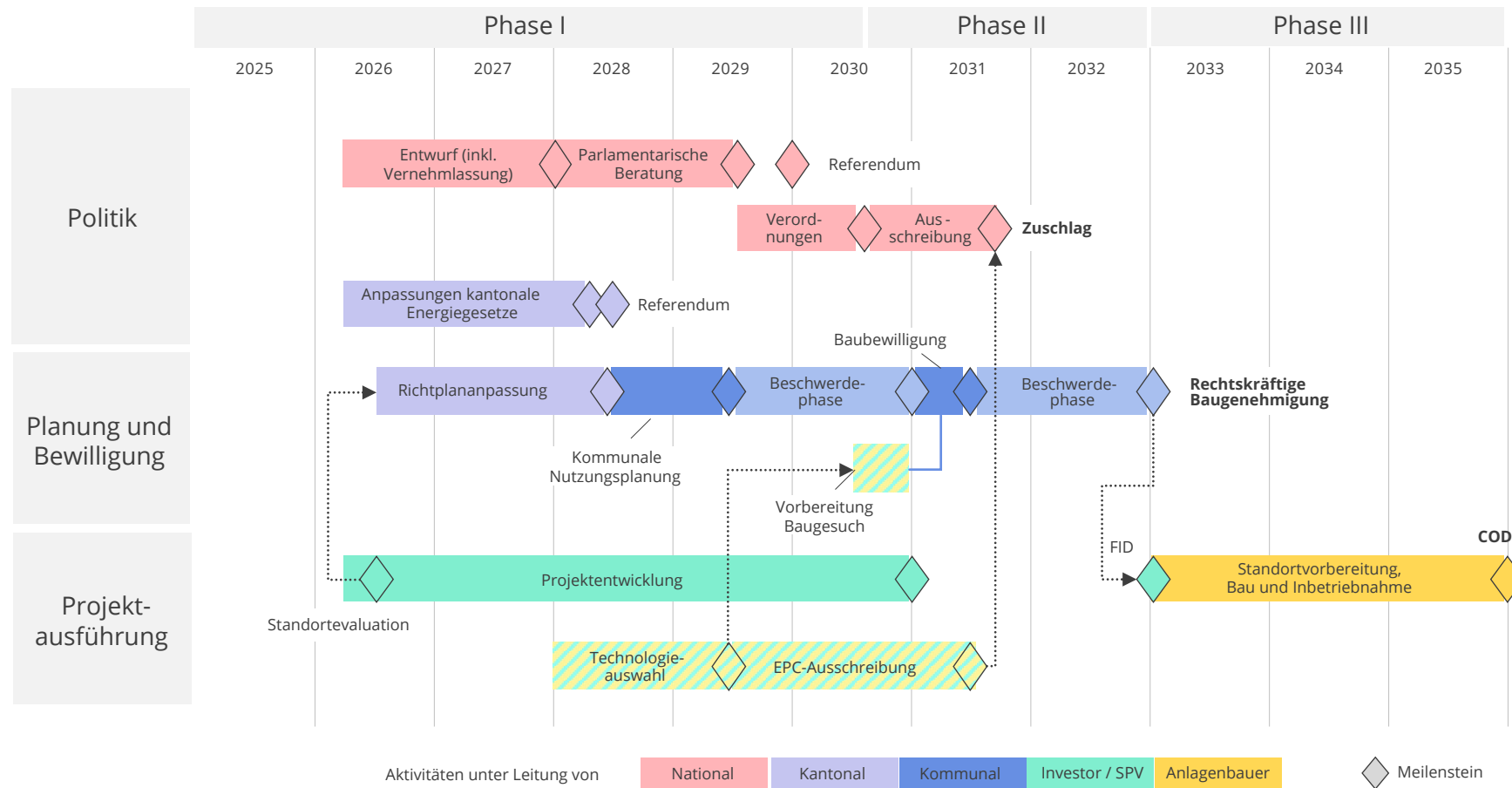


Figure 3: Schedule of a new gas-fired power plant divided into three phases

### Focus: Timing of a market-active gas-fired power plant for Switzerland

**Phase I “Creation of the legal basis”:** In terms of policy, a legal basis is needed at the federal level for the implementation of tenders for electricity generation capacity and the elimination of the double burden of ETS and CO<sub>2</sub> levies, in the form of an amendment to the Electricity Supply Act and a corresponding ordinance. At the cantonal level, the requirements for waste heat utilisation must be clarified in the relevant energy legislation (and the associated energy ordinances). In terms of planning, an amendment to the structure plan at cantonal level is likely to be required for a market-active gas-fired power plant, followed by an amendment to the municipal utilisation plan. For successful project implementation, it is crucial that sites are evaluated at an early stage so that work on adapting the structure plan can start immediately.

**Phase II “Tendering and obtaining legally binding building permit”:** Once the legal basis has been created, the federal government (or the electricity grid operator on behalf of the federal government) can then conduct a call for tenders for payments for additional winter capacity. At the same time, the documents required for the building permit can be prepared, starting with selection of the appropriate. After entry in the communal land-use planning, the building application can be submitted – typically at municipal level, but with the involvement of relevant cantonal specialist agencies (e.g. for noise, air quality and groundwater protection) as well as federal agencies (e.g. SFOE, FOEN). To shorten overall timelines, the evaluation of the power plant constructor can take place in parallel with the tendering process.

**Phase III “Construction and commissioning”:** The final investment decision can be made with the receipt of the legally binding building permit and the successful tendering of payments for additional winter capacity. To keep the construction period as short as possible, components with long lead times may need to be ordered in advance – accepting the associated cost risk.

suitable locations should be encouraged to include exemptions or simplified requirements for efficient CCGTs in their cantonal regulations with regard to waste heat utilisation.

As described above, cantonal climate targets can also represent a hurdle for the construction of gas-fired power plants. Efforts should be made to ensure that the cantonal targets are formulated and implemented in such a way that there is room for gas-fired power plants, at least if low-emission operation is possible in the future (for example by using renewable fuels or H<sub>2</sub> ready plants).

#### Subsidies

Under the current framework conditions, a gas-fired power plant cannot be realised economically without subsidies (see Chapter 5). This is also the case for renewable technologies.

A capacity market would be an appropriate instrument to promote gas-fired power plants. This could be operationalised via an

auction conducted by the federal government or Swissgrid with payments for additional winter capacity. To increase competition and broaden participation, the tender could also be designed to be technology-neutral. Capacity markets are already being used abroad (e.g. Italy, UK, Ireland, Belgium, Poland) to support the profitability of additional capacity or to compensate for its contribution to the security of energy supply. An electricity agreement between Switzerland and the EU would make such capacity markets possible, but they would have to be compatible with the EU state aid guidelines.

The amount of the required receivables is strongly linked to the expected operating hours. If a gas-fired power plant operates very rarely – or not at all – because it is not competitive under the additional tax burden in Switzerland, the capacity payment would need to cover the costs of the power plant al-

most in full. Conversely, the more profitable operating hours an investor can expect on the market, the lower the required subsidy payments.

#### **Reduction of the “Swiss finish” CO<sub>2</sub> levy**

Swiss gas-fired power plants can only compete internationally if their tax burden is comparable to those of other countries. To ensure this, the double burden of the CO<sub>2</sub> levy would have to be removed.

Specifically, the CO<sub>2</sub> levy should be fully refunded when participating in the ETS. This would require deleting Art. 17 para. 2 CO<sub>2</sub> Act, which introduces the minimum price. At the same time, an additional amendment to the law would have to ensure that renewable pipeline gas is exempt from the CO<sub>2</sub> levy. Similar exemptions should also be created for other low-emission solutions, such as CCS, by

explicitly mentioning them in the law and ordinance.

Without the removal of these distortions, gas-fired power plants would require higher subsidies, as their operation would be artificially more expensive and thus restricted compared to other countries.

The discrepancy in the tax burden could be reversed in future if Switzerland aligns with the EU by introducing an ETS for the buildings sector (known as EU ETS 2). Such a system will potentially be coupled with the existing EU ETS from 2031. On 12 September 2025, the Federal Council announced that it would be developing an ETS system similar to the EU ETS 2 for the areas of buildings and transport, which will potentially replace the CO<sub>2</sub> levy

from 2030.<sup>31</sup> This would eliminate the so-called “Swiss finish” charges.

#### **Ensure gas grid connection**

Today, Switzerland has no adequate legal framework for the gas market – currently only the Pipeline Act applies. This is accompanied by uncertainties regarding the connection conditions of a large gas-fired power plant to the gas grid and the securing of its gas supply (e.g. reserving a corresponding supply capacity in the gas grid). In October 2025, the Federal Council launched a new consultation process on a Gas Supply Act (GasVG) <sup>32</sup>. The GasVG would establish a clearer regulatory basis for the gas market. However, the bill must still pass through the full parliamentary process and a possible referendum.

<sup>31</sup> News Service Confederation, 2025, Federal Council discussed climate policy after 2030

<sup>32</sup> News Service Confederation, 2025, Renewed consultation on the Gas Supply Act



05

## Profitability

Market-active gas-fired power plants can generate revenue on the market, but subsidy is still required for economic operation.

### In brief

- For investments in 2035, our models show that operating a combined-cycle gas turbine (CCGT) plant with fossil natural gas and purchasing emissions trading system (ETS) certificates is the most economically attractive option of all the gas technologies considered.
- In 2035, the low-emission options biogas, CDR and e-methanol are unlikely to be competitive in the European electricity market. Due to the high marginal costs, these technologies would probably only be used as reserve or backup capacity.
- By 2050, low-emission options such as biogas, carbon capture and storage (CCS) and CDR are likely to become significantly more competitive. Their costs could approach those of conventional methane plus ETS certificate prices, making them more attractive. However, there is considerable uncertainty regarding the future development of the levelised cost of electricity (LCOE) for these low-emission technologies.
- Hydrogen and e-methanol power plants are not expected to be competitive before 2050. These technologies will continue to require significantly higher market prices or additional subsidy mechanisms, as their costs are likely to remain high over the long term.
- Market revenues are insufficient to fully cover the costs of any of the technologies considered. By 2050, the proportion of costs that can be covered by market revenues will increase for biogas, CCS and CDR. Nevertheless, considerable subsidy is still needed – particularly for hydrogen and e-methanol.

### 5.1

#### Costs and revenues

##### 5.1.1

#### Assumptions regarding cost parameters

##### Key assumptions:

- Due to a lack of infrastructure in 2035, hydrogen and CCS are not available as low-emission solutions; CDR would have to be procured mainly abroad.
- All options are based on CCGT.
- There is currently a shortage of combined-cycle and simple cycle gas turbines on the global market. Capital expenditure (CAPEX) has doubled in recent years. However, it is assumed that the market will ease in 2035 and that costs will be lower than they are today.<sup>33</sup>

### Methodological note

In the economic assessment, renewable methane is modelled as imported biogas with HKN, and renewable liquid fuels are presented as imported synthetic renewable methanol (e-methanol) produced with electrolysis-based hydrogen and biogenic CO<sub>2</sub>.

- All systems are designed as dual-fuel technology, which are either CCS or H<sub>2</sub> ready. We assume that both together increase the CAPEX of the CCGT by approximately 15 percent.<sup>34</sup>
- ETS certificates must be purchased for remaining CO<sub>2</sub> emissions. A refund of the CO<sub>2</sub> levy is still not possible.

<sup>33</sup> Levelized Cost of Electricity Renewable Energy Technologies (ISE, 2024), Axpo internal calculation.

<sup>34</sup> Expert assessment

## Techno-economic parameters 2035

- It is assumed that e-methanol is equivalent to a hydrogen power plant. Differences in fuel procurement (such as no pipeline connection and the need for local storage) are included in the fuel costs.
- It is assumed that e-methanol is produced in Spain. Higher costs would arise if the production of e-methanol were to take place in the Nordic countries (where CO<sub>2</sub> storage facilities are available).
- The costs of biogas produced in Europe are based on Axpo's internal calculation and IEA.
- WACC 4 percent<sup>35</sup>

2035 <sup>36</sup>		Natural gas		Biogas <sup>37</sup>	Natural gas + CDR	e-methanol
		+ ETS	+ ETS + CO <sub>2</sub> levy			
CAPEX	CHF /kW	1564		1564	1564	1642
Fix. O & M	CHF /kW / year	23		23	23	37
Service life	O	25		25	25	25
Var. O & M	CHF /MWh <sub>el</sub>	2		2	2	0.9
Fuel	CHF /MWh <sub>th</sub>	25 <sup>38</sup>		25	25	211
Energy efficiency	%	62%		62%	62%	59%
Separated CO <sub>2</sub>	tCO <sub>2</sub> /MWh <sub>el</sub>	-		-	-	-
CO <sub>2</sub> transport and -Storage	CHF /tCO <sub>2</sub>	-		-	-	-
	CHF /MWh <sub>el</sub>	-		-	-	-
Remaining CO <sub>2</sub>	tCO <sub>2</sub> /MWh <sub>el</sub>	0.323		-	0.323	-
ETS/GOO/CDR	CHF /tCO <sub>2</sub>	145.7 <sup>39</sup>		-	300	-
	CHF /MWh <sub>el</sub>	47.1		79 <sup>40</sup>	96.9	-
CO <sub>2</sub> release	CHF /tCO <sub>2</sub>	-	120	-	-	-
	CHF /MWh <sub>el</sub>	-	38.8	-	-	-
Resulting marginal costs	CHF /MWh <sub>el</sub>	87.4	126.2	119.3	137.2	357.6

Table 5: Overview of techno-economic parameters for 2035

<sup>35</sup> For the conversion of EUR to CHF: 0.9526, European Central Bank 2024

<sup>36</sup> The capacity is set at 2000 MW. All technologies are CCGT.

<sup>37</sup> Outlook for Biogas and Biomethane (IEA, Outlook for Biogas and Biomethane, 2024)

<sup>38</sup> IEA, 2024, World Energy Outlook, SP Scenario

<sup>39</sup> IEA, 2024, World Energy Outlook 2024, AP Scenario

<sup>40</sup> The GoO price listed here is higher than the current market prices, as we use the actual production costs for biogas. The assumed GoO corresponds to the difference between the natural gas market price and the production costs for biogas without subsidies.

## Techno-economic parameters 2050

## Important changes until 2050

- We assume that hydrogen will be produced in Spain and that a European-wide hydrogen infrastructure will be in place by 2050.
- The hydrogen costs shown here take into account production in Spain, compression, decompression, pipeline transport, and storage – that is all the logistics required to deliver the hydrogen to the power plant in Switzerland when needed. In addition, we assume a CAPEX surcharge of 5 percent for an H<sub>2</sub> ready power plant.
- The costs of CO<sub>2</sub> transport and storage are based on the assumption that a European pipeline infrastructure is fully developed, which links Switzerland with the central geological hubs

2050		Biogas	Natural gas + CDR	Natural gas + CCS <sup>41</sup>	Hydrogen <sup>42</sup>	e-methanol
CAPEX	CHF /kW	1402	1402	2804	1472	1472
Fix. O & M	CHF /kW / year	22	22	59	34	34
Service life	O	25	25	25	25	25
Var. O & M	CHF /MWh <sub>el</sub>	2	2	3.5	0.9	0.9
Fuel	CHF /MWh <sub>th</sub>	27	27	27	144	166
Energy efficiency	%	62%	62%	44,6%	59%	59%
Strapped CO <sub>2</sub>	tCO <sub>2</sub> /MWh <sub>el</sub>	-	-	0,372	-	-
CO <sub>2</sub> transport and -Storage	CHF /tCO <sub>2</sub>	-	-	66.7	-	-
	CHF /MWh <sub>el</sub>	-	-	24.8	-	-
Remaining CO <sub>2</sub>	tCO <sub>2</sub> /MWh <sub>el</sub>	-	0,323	0,033	-	-
ETS/GOO/CDR	CHF /tCO <sub>2</sub>	-	250	250	-	-
	CHF /MWh <sub>el</sub>	49	80.7	8.25	-	-
CO <sub>2</sub> release	CHF /tCO <sub>2</sub>	-	-	-	-	-
	CHF /MWh <sub>el</sub>	-	-	-	-	-
Resulting marginal costs	CHF /MWh <sub>el</sub>	120.5	93.4	233.3	268	

**Table 6:** Overview of techno-economic parameters for 2050, unchanged values compared to 2035 grey, values with changes black

<sup>41</sup> If Switzerland has the appropriate infrastructure (CO<sub>2</sub> pipeline, H<sub>2</sub> pipeline)

<sup>42</sup> Hydrogen production costs in Spain: EUR 5 /tonne<sub>2</sub>. Cost of hydrogen production | European Hydrogen Observatory, Aurora (Aurora, 2022)

connects. This results in significant cost reductions compared with today, where the current storage solutions and rail transport leads to costs that are roughly three times higher.

- The remaining emissions from CCS are offset via CDR.
- CAPEX will decrease for all technologies by 2050, given technological advances and economies of scale.
- We are taking into account stricter climate targets and higher CO<sub>2</sub> pricing via the ETS by 2050.

and divided by the total amount of electricity generated.

The LCOE depends heavily on the full load hours (FLH): The more hours a plant is operated at full capacity, the better the spread of fixed costs and the lower the average generation costs. Conversely, low-capacity utilisation leads to higher LCOE.

To determine the FLH, the marginal costs of a plant (i.e. the production costs of an additional kWh of electricity including variable costs such as fuels and CO<sub>2</sub> emissions) are compared with the hourly electricity market prices. The plant generates electricity in the hours in which the market price exceeds the marginal costs. The number of these hours gives the annual FLH for that technology. The hourly electricity prices used for this comparison are calculated using market simulations (see information box).

Figure 4 illustrates this approach for the year 2035: In the lower part, the price duration curve shows the decreasingly sorted hourly market prices in 2035, overlaid with the mar-

### 5.1.2 Methodological approach

The LCOE is the key figure for assessing the economic efficiency of gas-fired power plants. It indicates the average costs incurred over the entire service life of a system for the generation of one megawatt hour of electricity. All investment and operating costs, as well as fuel and CO<sub>2</sub> costs, are taken into account

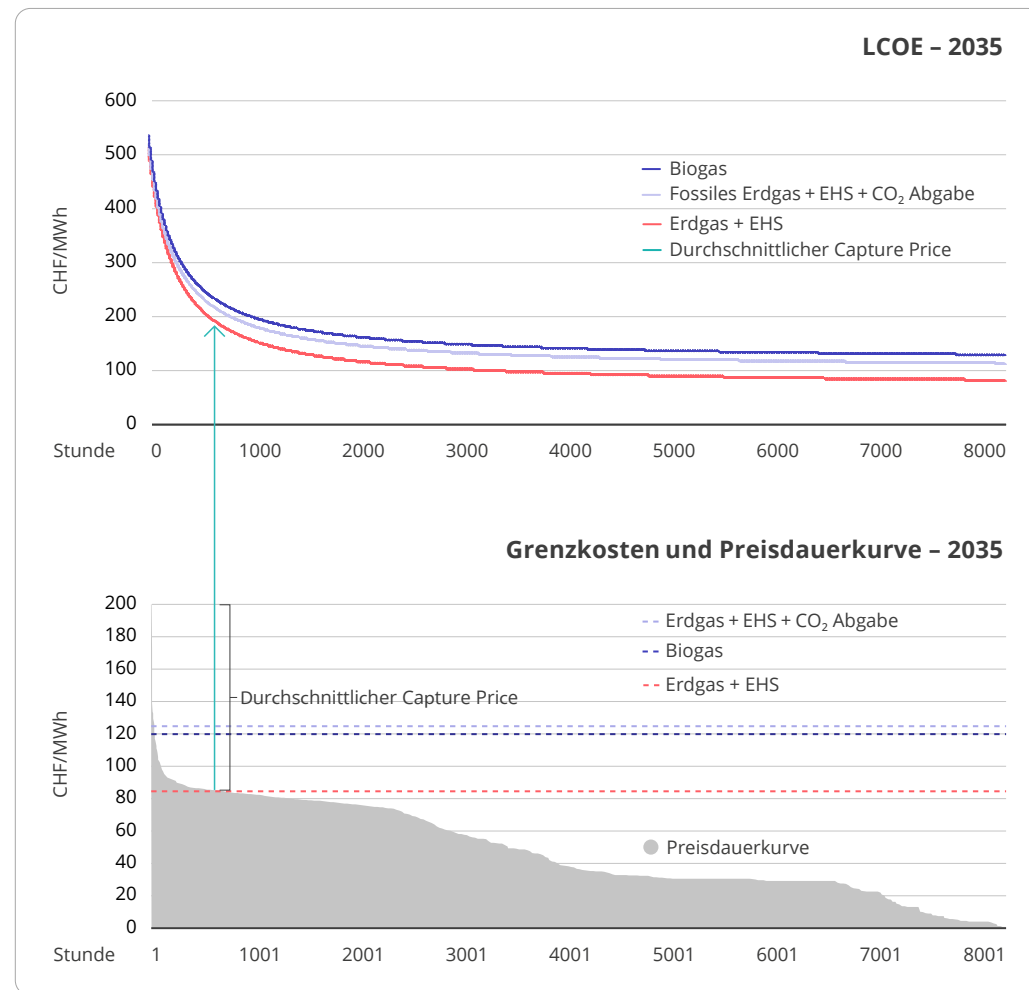


Figure 4: Example of how marginal costs are used to derive the FLH and what impact this has on the LCOE for different technologies.

ginal costs of different gas technologies. The point where the price duration curve intersects with the marginal costs indicates the profitable operating hours per year (i.e. the FLH). The upper part shows the LCOE as a function of the FLH. If a vertical line is drawn upwards from the FLH intersection to the LCOE curve, the corresponding LCOE for this utilisation can be directly read off. The graphical approach makes the relationship between market prices, cost structure, capacity utilisation and average generation costs clearly visible.

For the economic evaluation, we compare the market revenues of each gas-fired power plant technology with its LCOE. Revenue is derived from the capture price – the electricity market price realised by the power plant when it is used. This reflects the fact that certain technologies – such as hydrogen or e-methanol power plants – are mainly used during periods of high prices, while others, such as CCGT plants using fossil natural gas, are used more frequently and therefore achieve a lower average price.

### Where do electricity prices come from?

Nobody knows what electricity prices will be in the future. To understand how they might develop, we work with different scenarios – each representing different ways in which the markets could evolve. For a long-term view, we rely on fundamental models. These models are not based on historical data but explicitly model future power plants and load development, and simulate today's market mechanisms and pricing. Because the future is uncertain, we work with multiple scenarios and estimate a range of possible market developments, price levels, and therefore resulting income.

Our fundamental model simulates the electricity market in European countries, including Switzerland, for the period 2025 to 2060. The development of renewable energies, demand, cross-border import and export opportunities and other important market factors such as future prices for gas and CO<sub>2</sub> emissions are taken into

account. From this, we derive hourly future price scenarios, as well as power plant utilisation and hourly imports and exports for each country.

Two scenarios are analysed for other European countries. From these, we derive a range of possible income. The two scenarios differ as follows:

- In the first scenario, the decarbonisation of the global economy is making progress, but has not yet been fully achieved. The electricity sector in Europe will achieve 90 percent decarbonisation by 2050. Thermal power stations serve as a backup. Carbon capture and storage and hydrogen are used, but only to a limited extent. Demand for electricity is growing moderately.
- In the second scenario, global climate policy is more pragmatic and achieves 80 percent decarbonisation by 2050. Re-

newable energies dominate electricity generation, and gas is the most important backup power source. Electricity demand grows less than in scenario 1, due to lower demand from hydrogen electrolysis.

For Switzerland, a net zero scenario is assumed, in which decarbonisation increases demand. Details can be found in the Synthesis Report.

The prices for gas, CO<sub>2</sub> emissions and other primary energy are based on the Announced Pledges (AP) and Stated Policies (SP) of the IEA World Energy Outlook.

A validation was carried out in a study conducted together with FEN – the Research Centre for Energy Networks at ETH Zurich.

A direct comparison of these market revenues with the LCOE shows whether a plant can be operated to cover its costs or whether additional receivables are required.

### 5.1.3 Levelized cost of electricity

The LCOE of a gas-fired power plant depends heavily on how often and for how long the plant actually operates. If a system produces electricity for many hours a year, the fixed costs (e.g. investment and fixed operating costs) are spread over more units of electricity generated. This reduces the average cost per kilowatt hour. As described above in the methodological approach, the annual FLH result from the interaction of the marginal costs of the respective technology with the price duration curve.

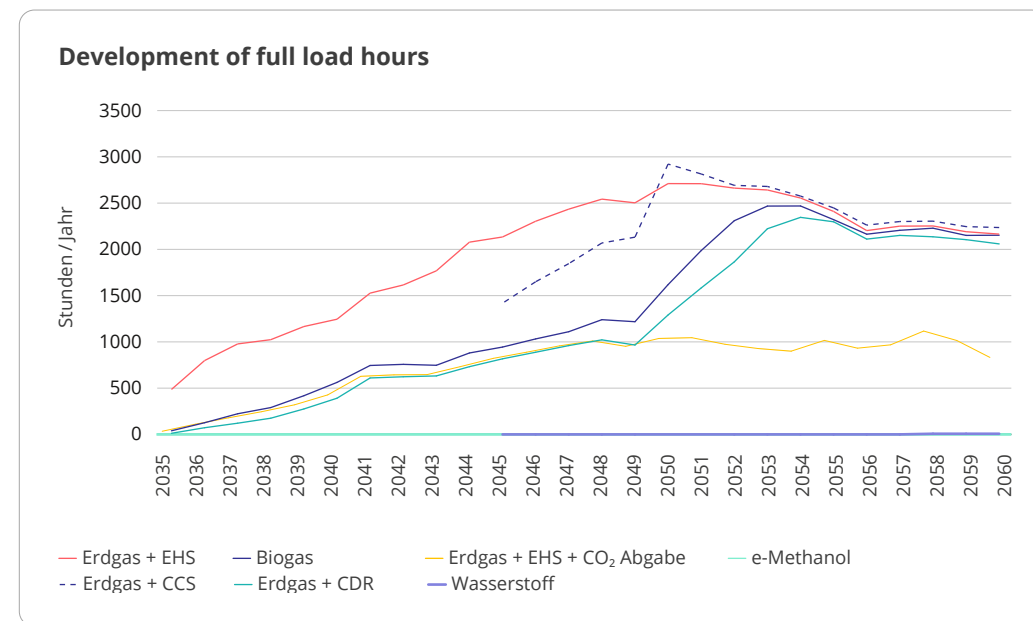
Figure 5 shows how the annual FLH of the technologies evolve from 2035 to 2060. For example, in 2035 only gas-fired power plants that operate with natural gas and participate in the ETS – but are exempt from the CO<sub>2</sub> levy – would be used. These plants reach around 500 FLH, typically during periods when re-

newable generation in Switzerland and neighbouring countries cannot meet demand (the so-called "dark doldrums").

If a CO<sub>2</sub> levy is levied on natural gas in addition to ETS participation, the marginal costs increase so much that a gas-fired power plant would barely be able to run under such a double burden – its operation would then be more like that of a reserve power plant. Plants that are operated with biogas, or that offset their CO<sub>2</sub> emissions via CDR, have similarly high marginal costs and would therefore also hardly be used.

Over time, the marginal costs of the respective technologies and thus also their FLH converge: By 2050, biogas, NET and CCS options will reach similar FLHs to fossil natural gas plants. This is partly because the marginal costs of fossil natural gas rise – particularly as ETS certificate prices are expected to increase with stricter climate targets – while the costs of biogas and NET fall in the model due to learning and economies of scale.

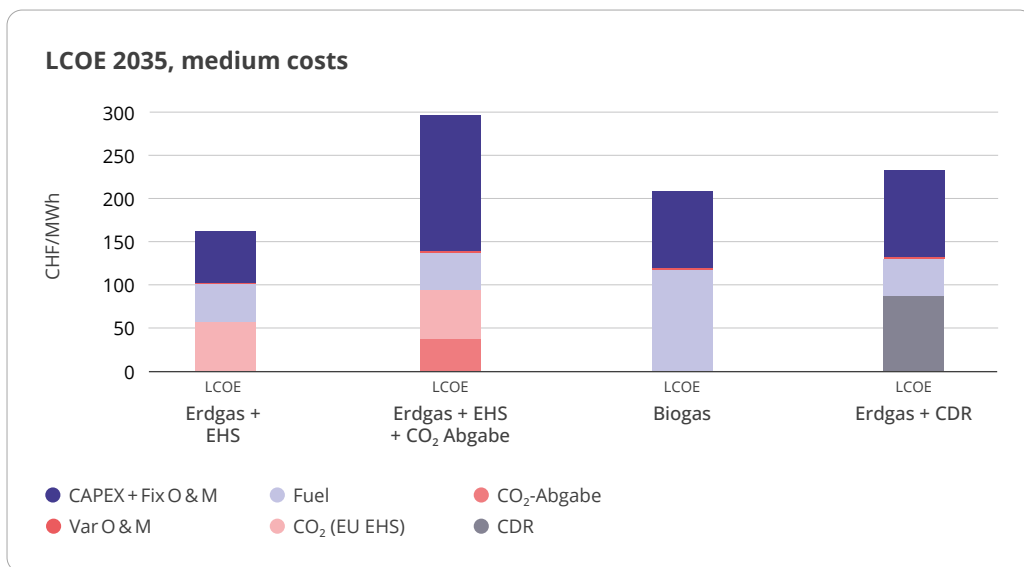
At the same time, the market is changing. As the share of renewable energies increases,



**Figure 5:** Development of full load hours (FLH) from 2035 to 2060 for each CCGT configuration, which shows the operational trajectories under the modelled market conditions. Higher FLH indicate higher capacity utilisation and greater potential for revenue generation.

there are many very favourable hours when large amounts of wind and solar power is available. However, the number of hours in which renewables are not sufficient is also rising – during these periods, the prices are very high because flexible technologies with

high marginal costs are typically used. This pattern of very favourable and very expensive hours means that gas-fired power plants will run more frequently and achieve more full-load hours by 2050 – even if natural gas becomes more expensive. After 2050, this



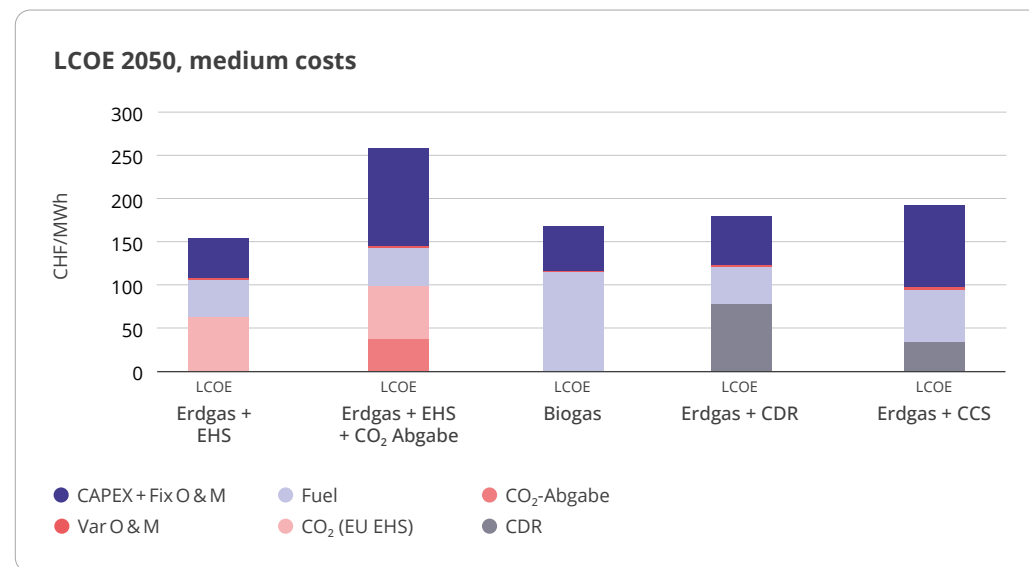
**Figure 6:** The chart shows the composition of the LCOE for each technology, divided into fixed costs, variable costs, fuel and CO<sub>2</sub> costs in 2035.

pattern stabilises, and the growth in full-load hours decreases for all options considered.

Neither e-methanol nor hydrogen power plants are used under the modelled conditions. In the case of hydrogen, the combination of high fuel prices and the additional need for transport and storage infrastructure

is particularly significant. As a result, the marginal costs are very high, restricting its use to only a few FLH.

The above cost assumptions and the calculated FLH result in the corresponding LCOE for the years 2035 and 2050 (see Figure 6 and 7). It is important to bear in mind that a system



**Figure 7:** The chart shows the composition of the LCOE for each technology, divided into fixed costs, variable costs, fuel and CO<sub>2</sub> costs in 2050.

has an expected service life of 25 years. A plant that is built in 2035 will therefore run until 2060. Because the cost developments – and therefore also the FLH – are strongly equalised by around 2050, the differences in the LCOE of the technologies considered are small.

For CCS, LCOE are only available from 2050. The reason: In 2035, CCS will not yet be available in the model because the necessary CO<sub>2</sub> infrastructure for transport and storage is still lacking. Only once infrastructure becomes available and CSS plants can operate appropriately from the 2040s onwards can meaningful LCOE be determined.

For hydrogen and e-methanol systems, the FLH are close to zero in the period under consideration. Under these conditions, no meaningful LCOE can be calculated because mathematically they would be extremely high. With such a low output, the fixed and capital costs cannot be effectively distributed over the amount of electricity generated and, as a result, the average cost per kilowatt hour rises sharply.

#### 5.1.4 Market revenue

The market revenue of a gas-fired power plant depends on two factors: the capture price achieved (the actual market price realised by the plant) and the number of operating hours. Both variables are essentially determined by marginal costs.

If the marginal costs are low, the power plant can produce economically for many hours. This leads to high FLH. However, because a larger proportion of generation takes place in "normal" hours with moderate prices, the average capture price tends to be lower. If, on the other hand, the marginal costs are high

(e.g. due to more expensive biogas or additional CO<sub>2</sub> levies), operation is only worthwhile in very expensive hours. Although the average capture price then rises, the FLH falls significantly – and the market revenue is lower despite the higher price level because the system runs less frequently.

An example (see Table 7) illustrates this effect: If the full CO<sub>2</sub> levy has to be paid in addition to the ETS (as under current legislation), the average marginal lifetime costs of a natural gas-based power plant increase from CHF 100 to CHF 137/MWh. As a result, the system only runs in very expensive hours; the average FLH dropped from 1975 to 745 (please note: Here average values over the service life of the system; between 2035 and 2045 the FLHs are significantly lower; see Figure 5). The average capture price rises from 139 Swiss francs to 185 Swiss francs per MWh. Nevertheless, the annual market revenue halves from 275 Swiss francs to 138 Swiss francs per kW because the number of operating hours falls sharply.

We expect market revenues to rise for all options by 2050. As described above, we are

#### Average annual market revenue in 2035 and 2050

2035		Natural gas + ETS	Natural gas + ETS + CO <sub>2</sub> Levy	Biogas	Natural gas + CDR
FLH	Hours per year	1975	745	1323	1323
Capture price	CHF/MWh	139	185	167	167
Market revenue	CHF/kW per year	274	137	220	220

**Table 7:** Derivation and comparison of the average annual market revenue of a plant in operation from 2035. All values represent the average values over the service life of the system.

2050		Biogas	Natural gas + CDR	Natural gas + CCS	Hydrogen
FLH	Hours per year	2189	2015	2498	<50
Capture price	CHF/MWh	154	158	149	281
Market revenue	CHF/kW per year	337	318	372	<5

**Table 8:** Derivation and comparison of the average annual market revenue of a plant in operation from 2050. All values represent the average values over the service life of the system.

seeing an increase in hours with very high electricity prices.

## 5.2 Subsidy requirements to achieve profitability

For gas-fired power plants, the focus is on the availability of controllable output. As such, we assess the profitability per installed and available capacity (Swiss francs per kW). The decisive factor is that the output can be reliably provided when needed – rather than whether the power plant operates continuously on the market. Possible support would typically be provided via a capacity mechanism (i.e. via payments per MW of available capacity, as also proposed in Chapter 4.2). Consequently, we compare the subsidy requirements of the various options on a consistent MW basis. This approach reflects the system benefits that gas-fired power plants provide, especially in winter – when electricity prices are high, renewable feed-in is typically low, and flexible, controllable capacity is particularly important for energy supply security and grid stability.

According to our models, operating gas-fired power plants with fossil natural gas and purchasing ETS certificates is the most economically attractive option in 2035 – assuming that these plants are exempt from the additional CO<sub>2</sub> levy. However, market revenues cannot fully cover the investments, so subsidy is required to ensure profitability. In this case, the subsidy would have to amount to around 45 Swiss francs per kW per year, covering 38 percent of the investment. Figure 8 shows the profitability of the options for 2035.

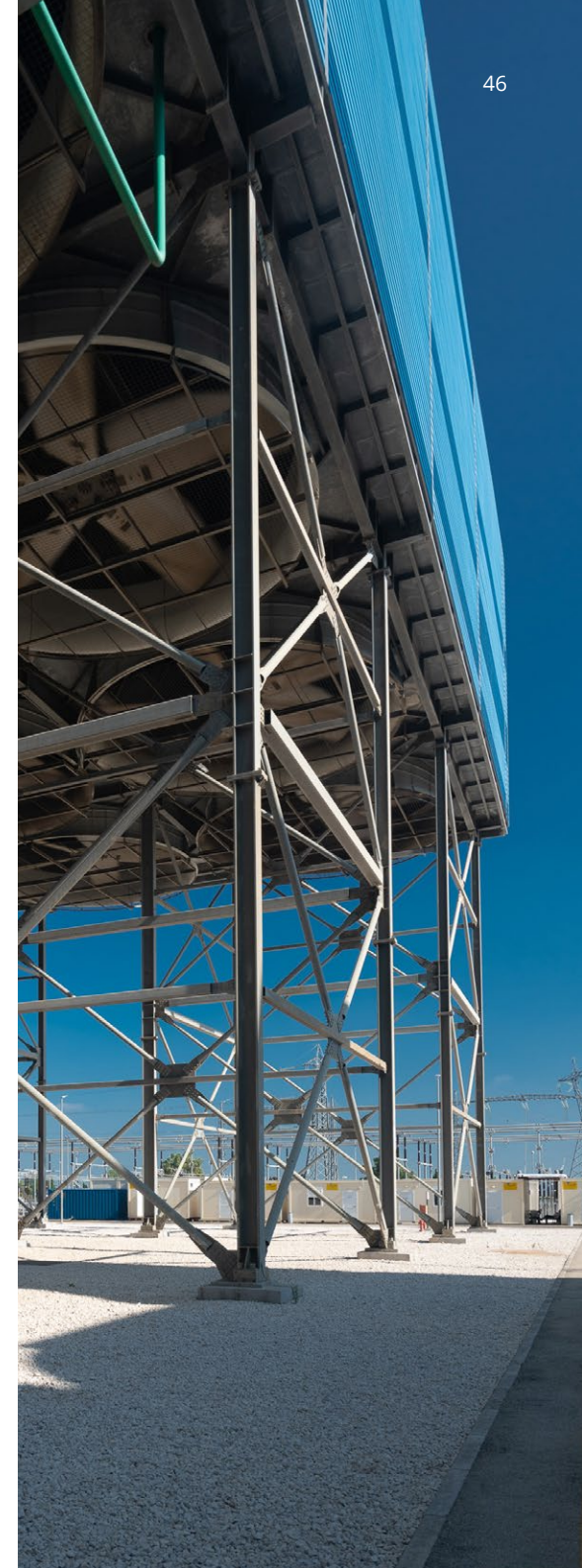
If the Swiss CO<sub>2</sub> levy continue to be levied in addition to the ETS, this the profitability of power plants fuelled by fossil natural gas will significantly reduce. The Swiss plants cannot compete with their European counterparts. This double burden from the ETS and CO<sub>2</sub> levy leads to a large gap between costs and market revenues, and the subsidy requirement almost doubles to around 84 Swiss francs per kW per year.

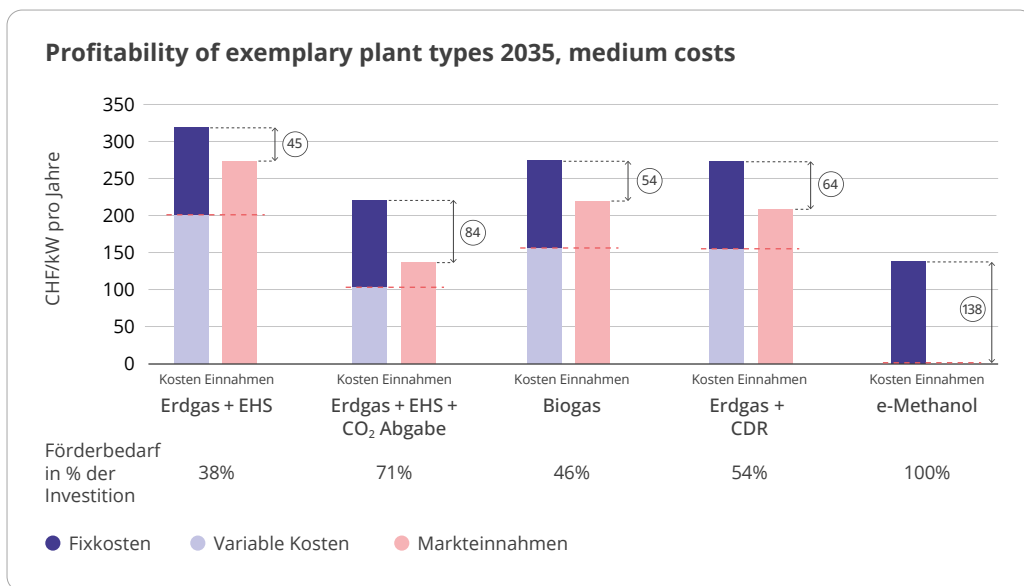
The calculation of profitability takes into account costs and income over the entire service life of the gas-fired power plant (here:

2035 to 2060). As the FLH of the CO<sub>2</sub> neutral options of biogas and CDR will increase over this period, the need for funding will also remain limited. Hydrogen and CCS are not yet taken into account here, as the necessary transport and storage infrastructure is still lacking for both options. Only with available infrastructure and corresponding operation from 2050 onwards can the profitability be meaningfully demonstrated.

As e-methanol is not expected to achieve FLH in 2035, the entire investment would have to be covered by a subsidy. This corresponds to the way reserve power plants are handled in Switzerland today. These are not used in the market and therefore cannot relieve the pressure on their financing through market revenues. Reserve power plants are therefore fully financed by the state.

By 2050, the CO<sub>2</sub>-neutral options biogas and CDR will become significantly more attractive and will be able to cover a large proportion of the investments with their market revenues (see Figure 9). Despite this progress, there is still a need for additional subsidy for all technologies to enable economical operation. For



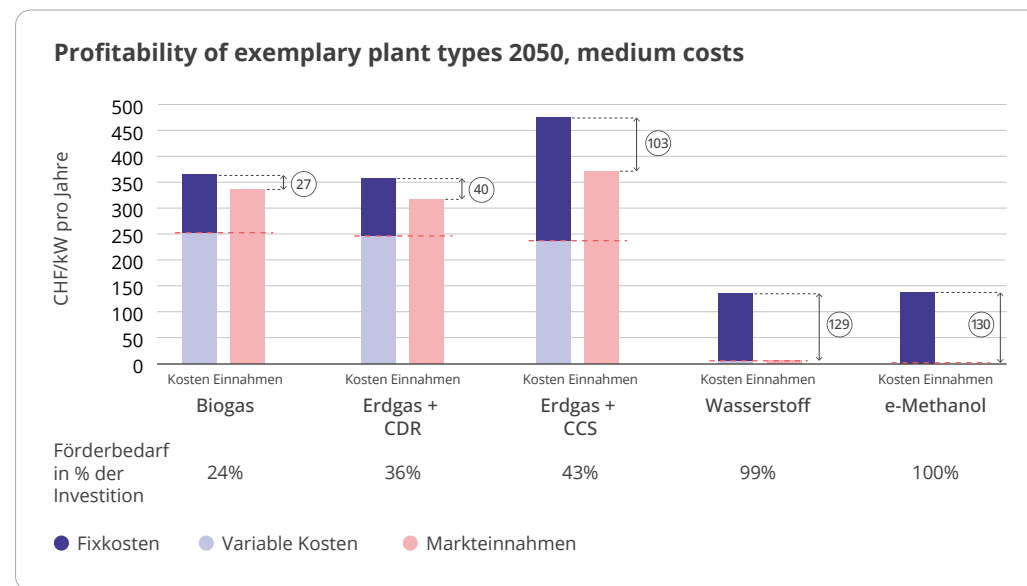


**Figure 8:** This chart shows the annual costs and revenues in CHF / kW per year, assuming an investment in an average 500 MW power plant in 2035 under the modelled price conditions.

example, a capacity market would still have to cover 24 percent of the total costs for biogas and 36 percent for CDR.

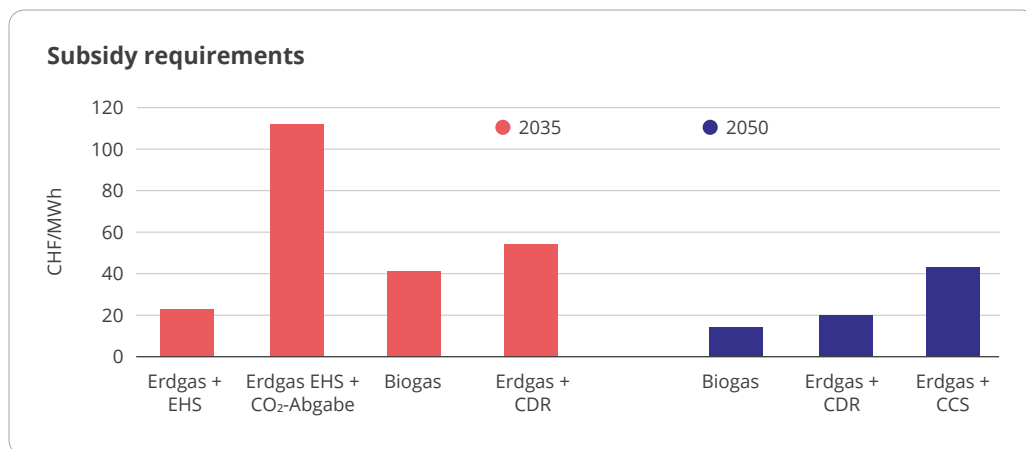
erate substantial market revenues due to high FLH, but has a significantly higher subsidy requirement than biogas and CDR due to high initial investments.

CCS and hydrogen are taken into account for 2050, as we assume the necessary infrastructure could be available by then. CCS can gen-



**Figure 9:** This chart shows the annual costs and revenues in CHF / kW per year, assuming an investment in an average 500 MW power plant in 2050 under the modelled price conditions.

Hydrogen and e-methanol achieve very few FLH and would also act similarly to reserve power plants in 2050.



**Figure 10:** Subsidy requirements for the generation of electricity from gas-fired power plants in winter.

### 5.3 Subsidy requirement for winter electricity

In addition to the basic profitability, the Axpo Energy Reports are particularly concerned with the meaningful contribution a technology can make to the electricity supply in winter. The key is to understand how expensive – and therefore how much subsidy is needed – a technology is in relation to the electricity produced in the winter half-year. In other

words: If the SFOE were to focus the subsidies exclusively on the winter half-year, the technology examined would have to receive the calculated subsidy corresponding to each MWh generated in the winter.

For comparability with other analysed technologies, we present the subsidy requirement based on the amount of electricity generated in winter (Swiss francs per MWh). This subsidy requirement is calculated as the difference between the capture price and LCOE (both values are shown in Chapter 5.1.4 for

all technologies considered). As gas-fired power plants in Switzerland are expected to generate electricity almost exclusively in the winter half-year, the annual results in this case can be transferred directly to the winter half-year.

For 2035, the subsidy requirement per unit of winter electricity is between 23 Swiss francs and 112 Swiss francs per MWh, with the lowest value occurring for operations using natural gas without CO<sub>2</sub> levy. It is worth noting that with a double burden from the ETS and CO<sub>2</sub> levy, the additional subsidy requirement (89 Swiss francs per MWh) is significantly higher than the actual CO<sub>2</sub> levy (120 Swiss francs per tonne of CO<sub>2</sub> corresponding to 38.8 Swiss francs per MWh). This is due to the increased marginal costs resulting from the CO<sub>2</sub> levy, which mean that the system is used less frequently on the electricity market and generates correspondingly lower market revenues. The additional subsidy requirement must therefore compensate not only for the higher costs resulting from the CO<sub>2</sub> levy, but also for the loss of market income. By 2050, the production requirement for all options

will fall significantly to between 14 Swiss francs and 43 Swiss francs per MWh.

### 5.4 Sensitivity analysis

Evaluating the profitability of gas-fired power plants requires careful consideration of various sensitivities. Depending on the development of CAPEX, fuel prices, ETS certificate prices and electricity market prices, marginal costs and FLH and thus the subsidy requirements may differ.

We take the following sensitivities into account (see Table 9):

- **CAPEX:** Fluctuations of around ±15 percent are plausible despite the high maturity of the gas-fired power plants. Recent price peaks for gas turbines were in this upper range due to the market situation. For CCS, the assumed fluctuation range is even higher at approximately 30 percent, as there is a lack of extensive operating experience and the supply chains are not yet sufficiently established. This uncertainty is underlined by current cost

estimates for offshore CO<sub>2</sub> transfer and storage, which see a significant increase in the cost level over the past few years.<sup>43</sup>

- Fuel costs:** Natural gas prices are volatile and can typically fluctuate by ±10 percent depending on the global commodity market and supply chain risks. With a fluctuation range of ±30 percent, prices for biogas are even more volatile due to the limited supply. The costs of CDR certificates are very uncertain and range between CHF 200 and 400 /tCO<sub>2</sub>. CDR certificates from NET in Switzerland tend to be at the upper end of the fluctuation range. Fluctuations of around 40 percent are to be expected for hydrogen, as the market and infrastructure are still being developed.
- ETS certificate price:** Prices for ETS certificates are very sensitive to political and market-related developments and have recently fluctuated between CHF 60 and

**Uncertainties of each technology**

	Natural gas + ETS	Biogas	CDR	e-methanol	CCS (2050 only)	Hydrogen (2050 only)
CAPEX	±15% (Current tight market for gas turbines leads to significant higher CAPEX)				±30% (limited operating experience)	±15%
Fuel costs	±10% (volatility of the global gas market)	±30% (Limited supply, volatile prices)	±10% (such as natural gas)	±20% (raw material, Transport)	10% (such as natural gas) -10+50% (CO <sub>2</sub> transport/storage)	±40% (H <sub>2</sub> production) ±50% (pipeline / infrastructure not available)
ETS / CDR <sup>46</sup>	CHF 80–250 / tCO <sub>2</sub> (politically driven)		CHF 200–400 / tCO <sub>2</sub>		CHF 200–400 / tCO <sub>2</sub> (CDR applies to residual emissions)	
Electricity market prices	Sensitivity scenario with different development of electricity mix and demand in Europe (depending on technology, effect on capture price between -5% +10%)					

**Table 9:** Overview of key uncertainties for each technology and year of investment. Unless otherwise stated, the uncertainties apply to both 2035 and 2050.

120 /tCO<sub>2</sub>. Political or regulatory changes can lead to rapid and significant price jumps. Future price levels will depend largely on climate policy and the organization of the market. In a scenario with ambitious decarbonisation targets, CO<sub>2</sub> prices could rise to around 250 Swiss

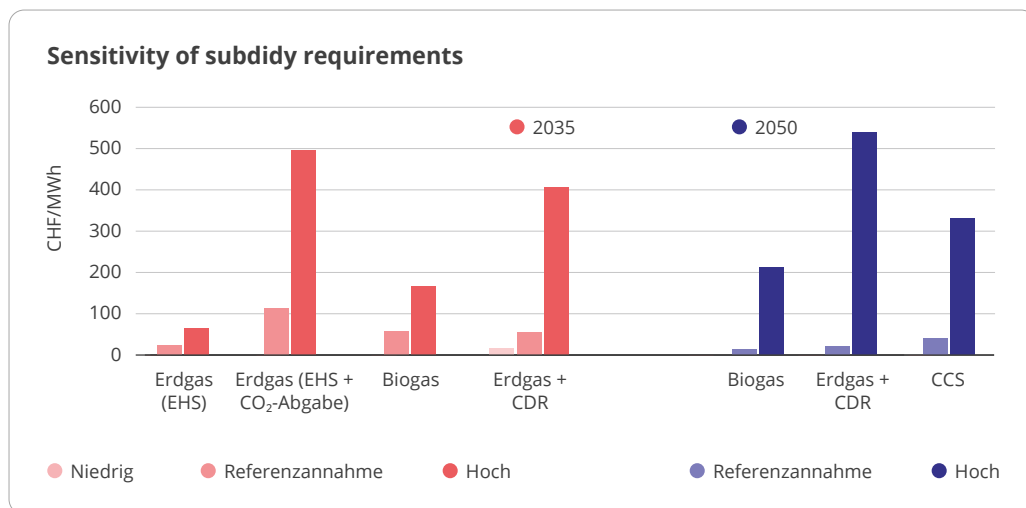
francs per tonne of CO<sub>2</sub> by 2050. However, in a future in which decarbonisation targets become less important, prices could remain at today's level. As such, the uncertainty range is wide and could cover average price levels of between 80 euros

and 250 euros per tonne CO<sub>2</sub> over the period under consideration.

- Development of electricity market prices:** For this purpose, we model an alternative scenario in which Europe will achieve only a 70 percent reduction in

<sup>43</sup> Agora Industrie, 2026, Carbon Capture and Storage (CCS) in the energy transition towards climate neutrality

<sup>44</sup> Assumed average range over time horizon



**Figure 11:** Sensitivity of the production requirement for winter electricity

greenhouse gas emissions by 2060 (instead of 90 percent). In Switzerland, it is still assumed that the net-zero target will be achieved in 2050. This sensitivity scenario assumes a slower expansion of renewable energies, lower electrification and reduced subsidy instruments. As a result, Europe remains more dependent on gas-based electricity generation, which leads to structurally higher electricity prices. As Switzerland is closely in-

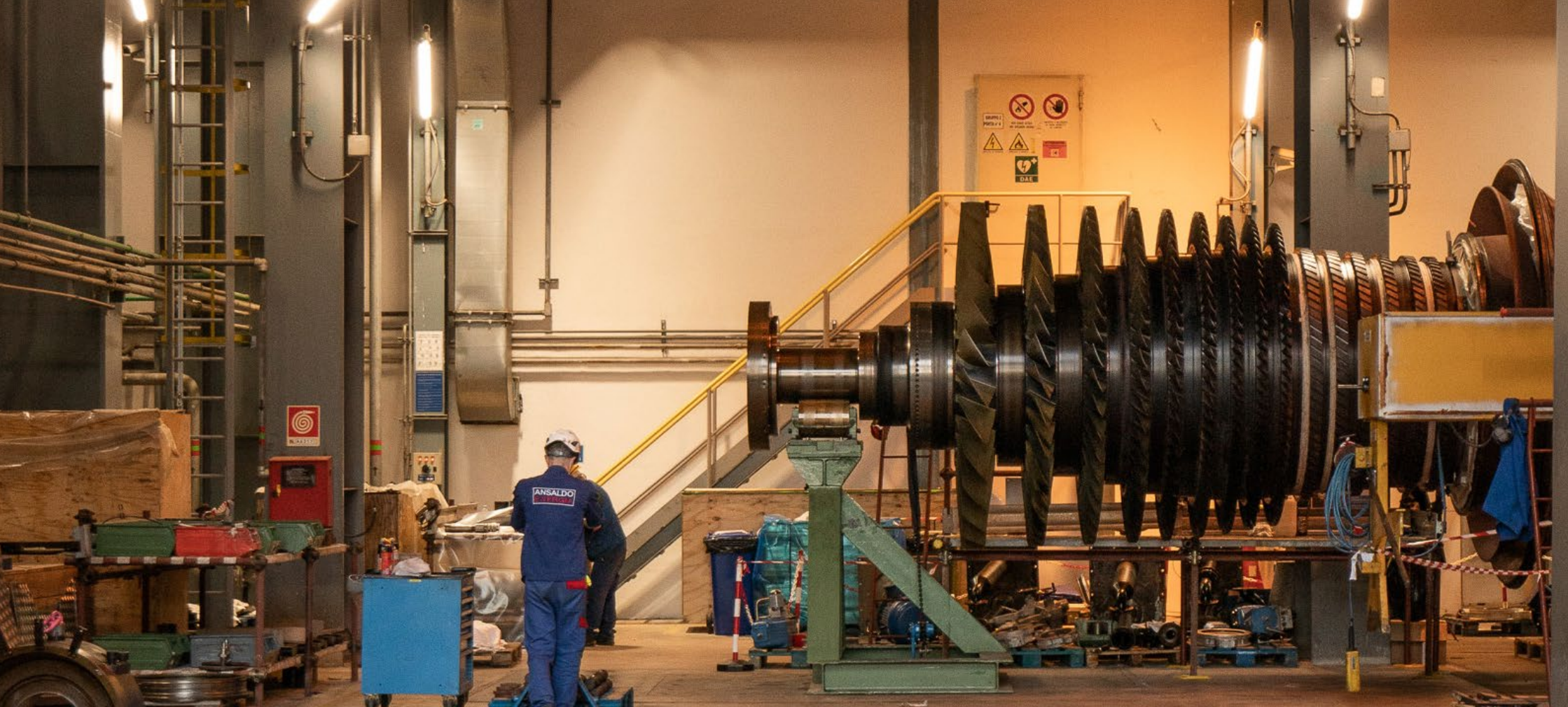
tegrated into the European electricity market, changes in the energy mix of neighbouring countries will also have an impact on Swiss electricity prices and therefore also on the deployment patterns of Swiss gas-fired power plants. Our analysis shows that the average capture price changes by -5 percent to +10 percent, depending on the technology, when comparing the main scenario to this sensitivity scenario.

If all uncertainties are considered at the same time, this results in a wide range in the profitability of gas-fired power plants. In Figure 11, we show this range using the worst case scenario (high CAPEX, high fuel costs, high carbon price and low market revenue), the best case scenario (low CAPEX, low fuel costs and high market revenue) and reference assumptions (as described in the previous chapter). Together, these scenarios illustrate the extent to which the necessary subsidy requirements can vary under different future conditions.

For fossil natural gas, the assumption regarding the development of ETS certificate prices remains the dominant driver of production requirements. In a scenario with high ETS certificate prices, the need for subsidies increases significantly, while it falls to zero for almost all technologies with low certificate prices.

It is interesting to understand at what ETS certificate price a gas-fired power plant using natural gas would be just as expensive as a gas-fired power plant using biogas or NET. To do this, we consider how much the ETS allowance price would need to rise on average be-

tween 2035 and 2060 (the operating period of gas-fired power plant commissioned in 2035) in order to offset the higher costs of CO<sub>2</sub> neutral options. For biogas, the ETS certificate price would have to be CHF 50 Swiss francs per tonne of CO<sub>2</sub> higher on average (i.e. increase from an average of 180 Swiss francs to 230 Swiss francs per tonne of CO<sub>2</sub>). For NET, the required increase is even higher – rising by an average of 93 Swiss francs to a total ETS price of 273 Swiss francs per tonne of CO<sub>2</sub>.



# 06

## Macroeconomic Impact

Domestic value added from investments in gas-fired power plants is low as power plant components are manufactured abroad and fuels are imported.

### In brief

- Investments in power plant components and expenditure on fuel are responsible for 46 percent of costs and are largely channelled abroad.
- Switzerland is completely dependent on foreign supplier countries and transit countries for fuel procurement and has no domestic storage facilities. It is therefore directly affected by geopolitical crises and price shocks.
- This results in a domestic value-added share of around 47 percent of the total costs over the entire service life of a gas-fired power plant.
- Investments in gas-fired power plants create 265 full-time jobs per TWh.

### 6.1

#### Value chain

The value chain of a gas-fired power plant can be divided into planning, financing, manufacturing, construction / installation, operation and fuels (see Table 10). For each of these steps, the respective share of costs can be recorded and divided into domestic and imported shares: Planning, financing, construction / installation and significant parts of operations are predominantly carried out in Switzerland and are responsible for around 54 percent of the costs. The manufacture of central components, such as gas and steam turbines, and fuel procurement are primarily carried out abroad and account for around 46 percent of costs.

Within the value chain, dependence on foreign countries for fuel procurement is the most critical factor. Switzerland is completely dependent on foreign supplier countries and transit countries, making it directly exposed to geopolitical crises and price shocks. In addition, Switzerland currently has no storage facilities of its own, meaning that no strategic gas reserves can be held (see Chapter 2.5).

One example of the impact of geopolitical crises is Russia's war of aggression against Ukraine, as a result of which Russian gas supplies to Europe have plummeted. The associated shortages led to gas price spikes of over 600 percent compared to the pre-war situation. Europe is currently replacing the missing volumes primarily with higher pipeline deliveries from Norway and a sharp increase in liquefied natural gas (LNG) imports from the USA, Qatar and other exporting countries. Switzerland felt these price and supply shocks directly.

### 6.2

#### Economic value added

To calculate domestic value added, all costs incurred within Switzerland are assigned an appropriate multiplier depending on the value creation step. This makes it possible to determine how much added value is generated from an expenditure. The multiplier is used to deduct the expected foreign inputs of a company in the corresponding sector. Depending on how many foreign inputs are required in a sector, a given amount of Swiss-franc expenditure results in more – or less

### Methodological note

The macroeconomic aspects of the generation technologies considered in the Axpo Energy Reports were analysed and processed by Swiss Economics. For detailed information, please refer to the separate analysis.

For the analysis, we consider a reference gas-fired power plant: It is powered by natural gas, participates in the ETS, has an installed capacity of 500 MW and runs 2,000 hours per year. The costs of this system correspond to the assumptions of a reference system described in Chapter 5.

**Breakdown of the value chain for gas-fired power plants in Switzerland**

	Planning	Financing	Production	Construction/ installation	Operation	Fuels
Value-added steps	<ul style="list-style-type: none"> <li>● Planning</li> <li>● Engineering</li> <li>● Feasibility studies</li> </ul>	<ul style="list-style-type: none"> <li>● Financing (Own and Liabilities)</li> <li>● depreciation</li> </ul>	<ul style="list-style-type: none"> <li>● Gas and steam turbine</li> <li>● Waste heat steam generator</li> </ul>	<ul style="list-style-type: none"> <li>● Buildings</li> <li>● Transport</li> <li>● Gas grid connection</li> <li>● Mains connection</li> </ul>	<ul style="list-style-type: none"> <li>● Operation</li> <li>● maintenance</li> <li>● Insurance</li> <li>● Marketing</li> <li>● Electricity</li> </ul>	<ul style="list-style-type: none"> <li>● Methane gas</li> </ul>
Cost share	1%	34%	15%	9%	10%	31%
of which national	92%	99%	0%	87%	93%	0%
Provider	Predominantly Swiss engineers and planning offices, operators	Financing by Swiss banks and operators (50:50%)	Specialised professionals products from foreign manufacturers	Mostly Swiss construction companies and installers, some European providers for specialised tasks	Maintenance, operation and marketing by operators, maintenance often also by foreign manufacturers, spare parts from abroad	Foreign gas
Significant Dependencies Abroad			Components are manufactured in various countries			High volatility in gas prices, methane production globally distributed across various countries (USA, Russia and several smaller countries)

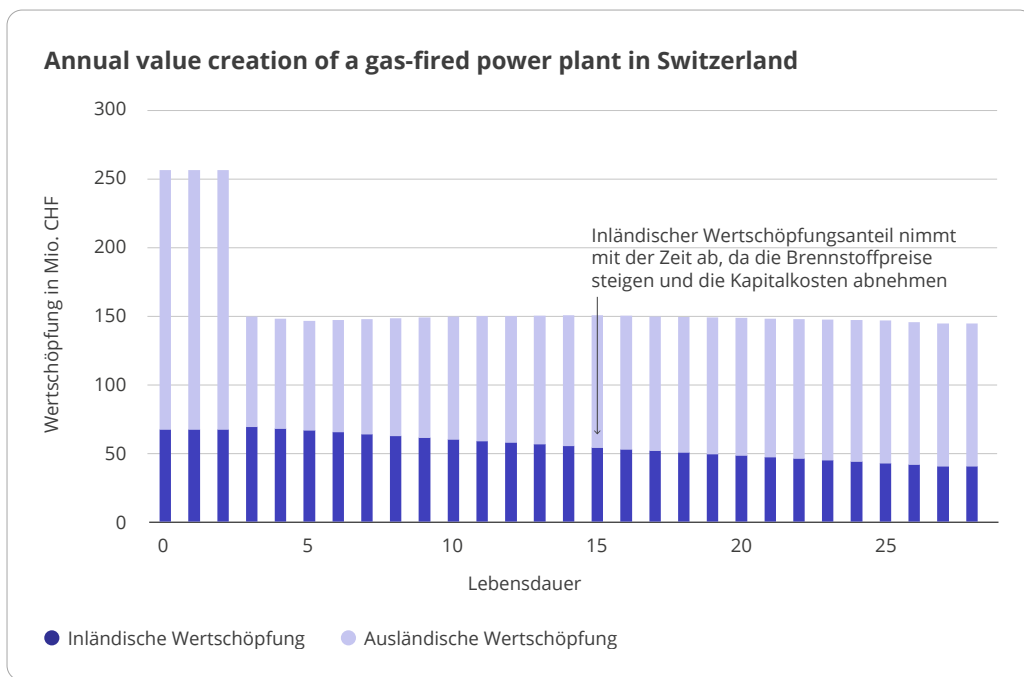
Dong-Hoon et al. (2021), BEF (2025)

● Local ● Abroad

– added value. Consequently, the same expenditure in different value chains does not generate the same added value. For a gas-fired power plant in Switzerland, this results in a domestic value-added share of around 47 percent of the total costs over the entire operating period.

As shown in Figure 12, value creation is spread over different phases of the asset's life cycle. During the three-year construction and planning phase, expenses are incurred for the planning, manufacture of the power plant components, as well as for construction and installation. This is followed by the operating phase, in which ongoing operating costs, fuel and ETS costs, capital costs, and depreciation are incurred. While the share of domestic value added in the construction phase is 26 percent, it reaches 54 percent in the operating phase. Based on the total costs of 3.4 Swiss francs billion, the reference gas-fired power plant (with an installed capacity

**Table 10:** Value chain and the associated Swiss/foreign cost shares of gas-fired power plants in Switzerland.



**Figure 12:** Value added of a typical gas-fired power plant over 25 years, divided into domestic and foreign shares.

of 500 MW and an annual production of 1 TWh) would generate domestic added value of 1.6 billion Swiss francs. This is divided into 0.2 billion Swiss francs in construction and

1.4 billion Swiss francs in operation. Over the entire life cycle, the domestic value added accounts for 47 percent of the total costs.

### 6.3 Employment

Investments in gas-fired power plants create jobs in Switzerland, measured in full-time equivalents (FTEs) –required over the entire life cycle of the plant. A gas-fired power plant in Switzerland generates 6629 FTEs over its entire lifetime, which is equivalent to 265 FTEs per year. Employment is unevenly distributed across construction and operation and is generated along the entire value chain. During the three-year construction phase 578 FTEs are created annually compared with 187 FTEs per year during operation.

### Value creation and receivables

In Switzerland, state subsidies typically cover a significant proportion of the costs of electricity generation. If the necessary subsidies are subtracted from the reported value added, the effective market-driven share of value added is correspondingly lower. In other words: A significant part of value creation is made possible only by government subsidy. If the corresponding subsidies are deducted from the value added, the domestic value added of the reference plant analysed is reduced from around 1.6 billion Swiss francs to 1 billion Swiss francs. The share of domestic value added in total costs will then fall from 47 percent to 36 percent.



# 07

## Environmental impacts

Gas-fired power plants fuelled by natural gas cause high greenhouse gas emissions but require little land and produce little hazardous waste.

### In brief

- Compared to the existing Swiss electricity mix, a gas-fired power plant fuelled by natural gas has high greenhouse gas emissions and associated damage to ecosystems; however, it has low land requirements, hardly any hazardous waste and moderate requirements for critical metals.
- Each TWh of natural gas electricity (~1.7 percent of Swiss electricity demand) would generate an additional 0.32 Mt CO<sub>2</sub>eq, equivalent to 0.8 percent of current annual emissions in Switzerland; looking ahead to 2050, this would amount to 2.6 percent of the 12 Mt CO<sub>2</sub>eq of unavoidable greenhouse gas emissions, which must be offset via CCS or negative emission technologies.
- However, these emissions must be considered in context. In the European electricity market, new gas-fired power plants in Switzerland would primarily replace old fossil-fired power plants over the next few decades, rather than renewable energies. In addition, gas-fired power plants can increase the security of the electricity supply and therefore help to advance the electrification of the economy. This electrification, even with the help of gas-fired power plants, leads to significantly lower emissions than today's fossil fuelled applications.

### 7.1

#### Comparison of environmental impacts to other technologies

A prospective life cycle assessment<sup>45</sup> is used to assess the environmental impact of power plants over their entire life cycle. All phases are considered – from the extraction of raw materials, plant construction and operation to dismantling and recycling. The analysis comprises six environmental indicators: Greenhouse gases, land requirements, damage to ecosystems, hazardous waste, radioactive waste and the need for critical metals.

The environmental impacts recorded in this way occur both in Switzerland and abroad. This geographical distribution differs from the cost allocation on which the value-added analysis is based. For example, expenditure on fuels is channelled entirely abroad, while emissions from combustion are generated domestically. Environmental impacts along the supply chain are also taken into account, such as fugitive methane emissions during

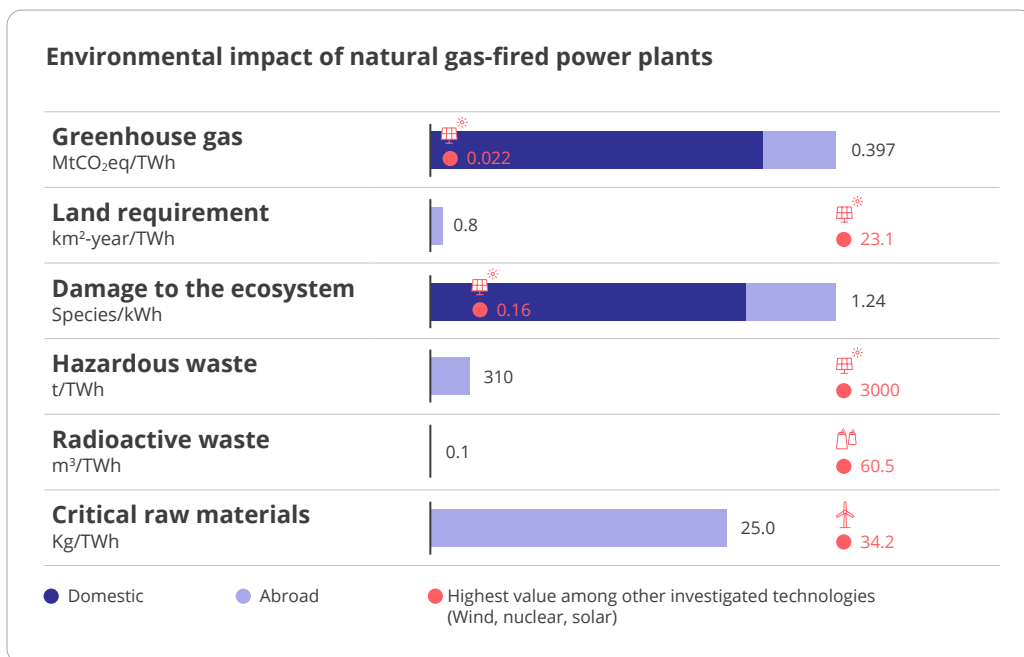
#### Methodological note

The environmental impact of the generation technologies under consideration was analysed and processed by the Paul Scherrer Institute (PSI). For detailed information, please refer to the separate analysis. The environmental impact is calculated over the entire life cycle of the power plants using LCA methodology.

A combined-cycle power plant is used as a reference power plant for the analysis. The 500 MW Power plant runs 2000 FLH and has a service life of 25 years.

Various fuels are taken into account in the analysis: Natural gas is available today. Biogas is technically feasible but will not be available in sufficient quantities until 2050. A variant with CCS and imported hydrogen is also considered for the years 2050.

<sup>45</sup> A prospective life cycle assessment (LCA) is a life cycle analysis that does not assess environmental impacts retrospectively with current data, but rather with a forward-looking approach under future conditions. It combines classic LCA methodology with scenarios or projections to assess how the environmental footprint of a product or process will develop in the future.



**Figure 13:** Environmental impact of a gas-fired power plant in 2035 compared to the highest (or next highest) values of other technologies

the extraction and transport of fuels. The prospective design of the LCA makes it possible to account for future developments up to 2050. The expected decarbonisation of the Swiss and global economy is also incorporated, so that, for example, the future electricity

mix – with an increasing share of renewable energies – is reflected in the calculations.

Figure 13 shows the environmental impact of a natural gas-fired power plant in 2035. For better comparability, the respective peak val-

ues of the other investigated technologies (nuclear power plants, rooftop PV, ground-mounted PV and wind power) are also presented. Gas-fired power plants fuelled by natural gas have a high environmental impact in terms of greenhouse gas emissions and the resulting damage to the ecosystem.

Important findings:

- Greenhouse gases consider the total emissions in CO<sub>2</sub> equivalents over the entire life cycle of a technology. Nuclear power achieves the lowest values. A gas-fired power plant fuelled by natural gas has the highest greenhouse gas emissions, with the largest share coming from the operation or combustion of natural gas.
- Land requirement describes the total area that a technology requires directly on site or in its upstream supply chains. Ground-mounted PV systems require the most space. Natural gas has a moderate land requirement, as relatively little land is required for the extraction, transport, and on site infrastructure.
- Damage to the ecosystem covers the loss of species caused by emissions, land use, raw material extraction, water consumption and climate impact. For gas-fired power plants, direct greenhouse gas emissions from the combustion of natural gas are the dominant driver of ecosystem damage. These emissions lead to global warming, altering habitats and resulting in species decline. Additional impacts arise from pollutants, land use and water consumption across the plant's entire life cycle.
- Hazardous waste includes hazardous, non-radioactive waste from mines and refineries that must be stored underground. Ground-mounted PV systems perform worst here, due to the high proportion of copper used in the production of the modules. Gas-fired power plants generate comparatively little hazardous waste.
- Radioactive waste refers to highly radioactive residues that must be stored in deep geological repositories. Nuclear power generates the largest amount of

such waste. For gas-fired power plants, the very small amounts of radioactive waste in the supply chain are generated indirectly by the electricity mix used in the manufacture of components.

- Critical metals are needed in only very small quantities for gas-fired power plants. Lithium, cobalt and neodymium play practically no role, and nickel is used in small quantities for high-temperature-resistant superalloys. Gas-fired power plants are predominantly made of steel (typically > 90 percent of the mass). Compared to wind turbines, gas-fired power plants require significantly fewer critical metals.

widespread use is not expected to be available until the 2040s at the earliest. E-methanol is not analysed, as a reliable quantification would require extensive and uncertain assumptions about the type and origin of the CO<sub>2</sub> source. CDR is also not taken into account for the same reasons: The underlying negative emission technologies are too heterogeneous to be able to make a specific and robust statement in this context.

Important findings:

- The operation of gas-fired power plants with **natural gas** generates direct greenhouse gas emissions that largely correspond to domestic emissions. In addition, further greenhouse gas emissions are generated along the supply chain – the majority of which occur abroad. These are attributable to the extraction, processing and transport of the natural gas and include emissions from energy-intensive process steps as well as methane and CO<sub>2</sub> emissions as a result of leaks.

7.2 Focus on greenhouse gas emissions

Figure 14 compares the lifetime greenhouse gas emissions of a gas-fired power plant fuelled by natural gas with potential low-emission alternatives for the years 2035 and 2050. Hydrogen and CCS are only included for 2050 – consistent with the profitability analysis – because the infrastructure required for their

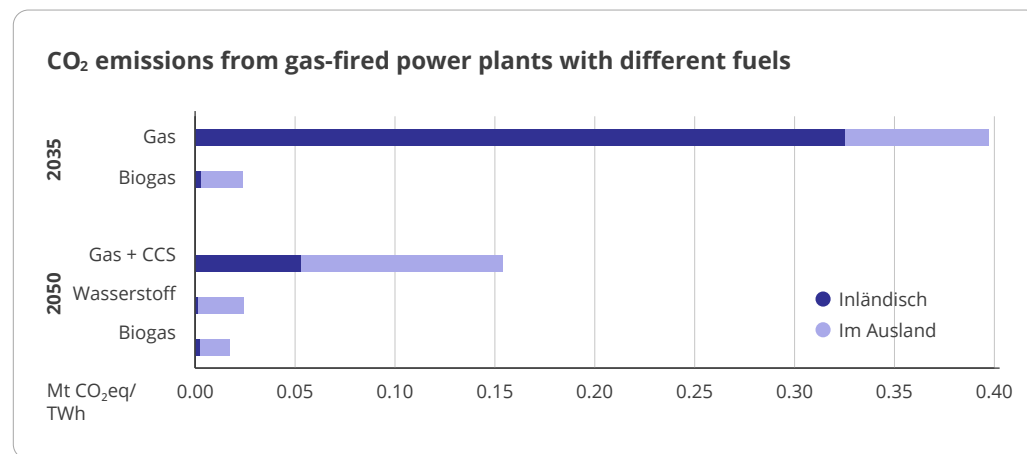


Figure 14: CO<sub>2</sub> emissions from gas-fired power plants with different fuels. The low-emission options with hydrogen, biogas or CCS will not be available until 2050.

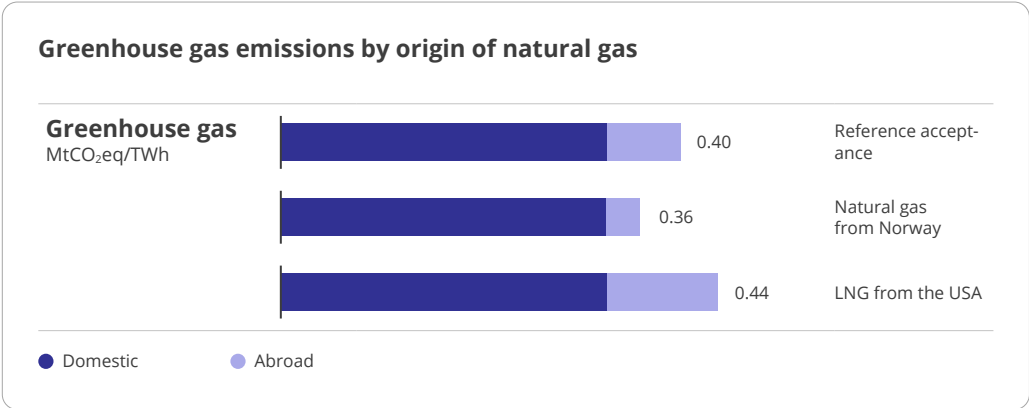
- The use of **Biogas** reduces domestic greenhouse gas emissions during operations to almost zero. It is assumed here that the biogas is imported from abroad. Remaining emissions are attributable to production and transport from abroad. Overall, this results in a significantly lower level of emissions than when using natural gas.
- The use of **CCS** reduces direct emissions from the operation of gas-fired power plants by around 85 percent –substantially, but not entirely. At the same time, the emissions generated abroad increase. This is due to the increased energy requirement for the capture, transport and storage of CO<sub>2</sub> and CO<sub>2</sub> losses (slippage) during the process. It is assumed here that the captured CO<sub>2</sub> is transported via pipeline and stored in

the North Sea. Overall, greenhouse gas emissions are reduced by slightly less than half compared to using natural gas alone. In order to achieve emission levels comparable to those of biogas or hydrogen, the remaining residual emissions would have to be compensated through additional measures, such as CDR.

- The use of **hydrogen** produces almost no domestic greenhouse gas emissions during operation. It is assumed here that the hydrogen is produced in Spain using electricity from ground-mounted PV plants and transported to Switzerland via a pipeline. The relevant emissions are therefore mainly generated abroad and result from the upstream life cycle phases of the PV plants and electrolysers, as well as from the energy required for compression and transport. Overall, the emissions profile is comparable to that of biogas.

the supply chain. This is particularly evident in the comparison between pipeline gas (e.g. from Norway) and natural gas imported as liquefied natural gas (LNG) ( e.g. from the USA). While Norwegian natural gas is transported directly to Switzerland via existing pipeline infrastructures, the LNG supply chain is significantly more complex and energy-intensive. It requires additional process steps including liquefaction of the natural gas, intercontinental shipping, and subsequent regasification. These additional steps lead to higher energy consumption and therefore increased greenhouse gas emissions. As can be seen in Figure 15, the difference is considerable. LNG imported from the US causes more greenhouse gas emissions along the supply chain than natural gas imported via pipeline from Norway. For the presentation of the environmental impact of natural gas-fired power plants in Figure 13 and Figure 14, it is assumed that half of the fuel comes from Norway and half the US respectively<sup>46</sup>.

The origin of natural gas has a significant influence on the environmental impact along



**Figure 15:** Influence of gas origin on greenhouse gas emissions. Two import paths are shown as examples: Natural gas from Norway, which enters Switzerland via pipelines, and LNG from the USA, which is then regasified in Germany and enters Switzerland via pipelines. The reference assumption is based on a 50-50 split.

Each TWh of electricity generated from natural gas (approximately 1.7 percent of today's Swiss electricity demand) would cause an additional 0.33 MtCO<sub>2</sub>eq in operation emissions under the assumed source mix. These emissions would be fully attributed to Switzerland and therefore have a direct impact on the national climate balance. By way of comparison: In 2024, Switzerland emitted a total of around

41 Mt CO<sub>2</sub>eq (excluding international aviation). One TWh of natural gas electricity therefore corresponds to 0.8 percent of the country's current annual emissions. Looking ahead to 2050: According to Energy Perspectives 2050+, around 12 Mt CO<sub>2</sub>eq of unavoidable greenhouse gas emissions remain in the net-zero target year, despite extensive decarbonisation, and these must be offset via CCS

<sup>46</sup> The origin of natural gas also affects the other environmental indicators. The derivation can be seen in the detailed analysis report in Chapter 6.7.

or negative emission technologies. One TWh of natural gas electricity increases this demand by 2.6 percent.

However, it is important to consider these emissions in context:

- **European electricity market:** In the European electricity market, new Swiss gas-fired power plants would primarily replace old, inefficient fossil fuel plants. Renewable energies such as wind and solar as well as nuclear power plants remain unaffected, as they operate first due to their low marginal costs. The European power plant fleet is still a long way from decarbonisation before 2035 and replacing old gas-fired power plants with modern Swiss plants would not increase overall European emissions. From the 2040s onwards, however, there is a growing risk that Swiss fossil-fuelled plants will increasingly displace low-CO<sub>2</sub>

or CO<sub>2</sub>-free gas-fired power plants elsewhere in Europe – unless they themselves operate with low-CO<sub>2</sub> or CO<sub>2</sub>-free fuels.

- **Swiss energy system:** Gas-fired power plants can increase the collateral security of the electricity supply and thus help to further advance electrification. This electrification, even with the help of gas-fired power plants, leads to significantly lower emissions than today's fossil fuelled applications. In heat production, a gas-fired heating system supplies around 0.9 kWh of heat per kWh of natural gas, while a CCGT (approx. 55 percent efficiency) combined with a heat pump (COP ≈ 3) generates around 1.65 kWh of usable heat from the same amount of gas – almost twice as much. Similar in transport: An internal combustion engine only converts around 20–25 percent of the energy contained in the fuel into motion,

while a combined cycle power plant together with an electric car achieves an overall efficiency of around 50 percent. In both cases: If fossil fuels are to be used at all, the detour via the large power plant and electrification is more efficient and therefore lower in emissions than direct combustion in heating or engines.

Electric vehicles and heat pumps would continue to run primarily on renewable electricity, while gas-fired power plants would only be used for hedging in times of insufficient renewable electricity generation due to their high costs. Accordingly, the decarbonisation of the mobility and heating sector would continue to be very far-reaching.



# 08

## Conclusion

The low-emission operation of gas-fired power plants is technically feasible in various ways, but these options are still associated with uncertainties and are unlikely to become economically viable until the 2040s at the earliest. If gas-fired power plants are to be able to contribute to energy supply security in Switzerland before then, timely adjustments to the regulatory framework are necessary.

At present, gas-fired power plants – except for combined heat and power (CHP) plants and reserve power plants – are not being actively addressed in social and political debate. In contrast to many other European countries, market-active gas-fired power plants are effectively excluded by Swiss policy (as part of the CO<sub>2</sub> legislation). Nevertheless, should gas-fired power plants be used in Switzerland, several implications arise.

### **State subsidies are necessary for the construction of gas-fired power plants.**

Like all other power generation technologies, gas-fired power plants cannot be operated economically without state subsidies. If gas-fired power plants make a significant contribution to the security of energy supply by generating additional winter electricity, an appropriate subsidy instrument is needed. A capacity market – an instrument, already used abroad, for ensuring sufficient production capacity – appears to be an appropriate solution. In Switzerland, this could be implemented through a tender for additional winter capacity, also open to gas-fired power plants. Within the tender, power plant operators

could receive a subsidy to compensate for the difference between market revenues and costs, a gap sometimes also referred to as "missing money".

### **Low-emission operation of gas-fired power plants is not competitive in the medium term. Which solution is by 2050, is still open.**

In general, gas-fired power plants are flexible in the use of different energy sources (fossil gas, biogas, H<sub>2</sub> admixture, synthetic fuels) as well as potential retrofitting / equipment with CO<sub>2</sub> capture. However, low-emission operation of gas-fired power plants would hardly be feasible in the medium term (2035): Although biogas, CDR and e-methanol are technically conceivable, they would significantly increase the production costs of Swiss power plants. This would make them uncompetitive in the European market, and their very low number of operating hours would mean that their investment would have to be heavily subsidised. Another crucial prerequisite would be the timely scaling up of production and supply chains for these low-emission solutions, which remains highly uncertain.

As things stand today, the European electricity market will have to switch to low-emission solutions by 2050 (EU climate targets, EU ETS requirements). This creates a level playing field at European level for low-emission gas-fired power plants. From today's perspective, certificate solutions, for example via biogas certificates or CDR certificates, appear to be the most cost-effective. However, the market development for these certificates, including availability and prices, is extremely uncertain. If a hydrogen or CO<sub>2</sub> infrastructure is available by then, hydrogen or carbon capture and storage (CCS) would also be possible solutions, but would probably be significantly more expensive than the certificates. In the case of a solution with CCS, substantial residual emissions remain despite capture. These are significantly higher than those of other low-emission options and would therefore have to be offset with CDR certificates, for example, although CDR certificates are currently not recognised under the ETS from a regulatory perspective. In addition, the chemical separation process used in CCS systems limits the speed at which the plant can change its load change, reducing its suitability for use during peak load situations.

One advantage of gas-fired power plants is that they can initially remain open regarding which low-emission solution will be adopted by 2050. The system can be retrofitted depending on technological developments – for example whether an infrastructure for hydrogen becomes available. In principle, the system can therefore be designed both H<sub>2</sub>-ready and CCS-ready (e.g. choice of gas turbine, sufficient space for retrofitting).

While the use of different low-emission solutions remains possible in principle, a clear national strategy at an early stage would be helpful. This would provide planning security for project developers and help reduce costs. Additional technical requirements, such as space requirements for subsequent CCS retrofitting or the purchase of H<sub>2</sub>-ready turbines, raise project costs. It is therefore important that national and regional infrastructure development be promoted at a higher level.

### **Regulatory adjustments are central: The double burden via the CO<sub>2</sub> levy must be removed and the Requirements for waste heat utilisation must be adjusted.**

Swiss gas-fired power plants can only compete internationally if their tax burden is comparable to those of other countries. For fossil gas-fired power plants, this means that when participating in the EU Emissions Trading System (EU ETS), the Swiss CO<sub>2</sub> levy should be fully reimbursed instead of only partially. Without eliminating this distortion, gas-fired power plants would require significantly higher subsidies, as their operation would be artificially more expensive than abroad and therefore economically restricted. The additional subsidy requirement is significantly higher than the amount that would be collected via the CO<sub>2</sub> levy. Currently, the CO<sub>2</sub> levy would even apply to the use of renewable gas imported by pipeline.

In addition, the provisions regarding waste heat utilisation should be adapted to allow gas-fired power plants to meaningfully fulfil them. In principle, combined-cycle gas turbine (CCGT) operations should be considered sufficient heat utilisation. In view of the role of gas-fired power plants for Switzerland's energy supply security, a corresponding requirement at federal law level seems appropriate. As part of these provisions, it could

also be ensured that gas-fired power plants comply with certain minimum requirements for heat utilisation. As an alternative approach, the cantons with suitable locations could be encouraged to provide for exemptions or facilitations for efficient CCGTs in their cantonal heat-utilisation regulations.

**Market-active gas-fired power plants have lower subsidy requirements than reserve power plants, but emit more domestic CO<sub>2</sub>.**

Market-active gas-fired power plants continuously generate revenues on the electricity market and are thus able to cover a substantial part of their costs. As a result, they tend to require less state support than pure reserve power plants, which are primarily kept in reserve for rare scarcity situations and therefore do not generate any market income. Likewise, market-active gas-fired power plants would generally reduce import demand, while reserve power plants would not supply any energy without imminent market failure. Another advantage of market-active gas-fired power plants is that they help to limit the rise in electricity market prices in



shortages because they increase the supply of electricity in the market, unlike reserve power plants.

As market-active gas-fired power plants would continue to operate on fossil natural gas in the medium term, they would generate corresponding CO<sub>2</sub> emissions. However, they would be used in Switzerland above all if it is not possible to import enough energy from neighbouring countries or if the prices for it are correspondingly high; in such situations, Swiss gas-fired power plants could at the same time substitute foreign fossil plants, which would in turn be associated with the same or possibly even higher CO<sub>2</sub> emissions. From the 2040s, however, it will become more likely that Swiss fossil plants will increasingly displace low- or CO<sub>2</sub>-free European gas-fired power plants, provided that they themselves continue to run on fossil fuels.

Reserve power plants, by contrast, do not run or only run infrequently, which means their overall emissions intensity is generally less significant. Low-carbon designs (e.g. with low-emission fuels) can significantly increase

their eligibility for approval and social acceptance. However, the economic cost-benefit ratio of low-carbon operation is likely to be very poor for reserve power plants, as they have to be available for bottlenecks and will ultimately not produce much.

**Market-active gas-fired power plants will be available from 2035 at the earliest.**

The realisation of market-active gas-fired power plants in Switzerland – including the prior adjustment of the regulatory framework – can realistically be expected to take at least 10 to 15 years. The legal basis for an appropriate subsidy system must first be created, which would need to go through consultation, parliamentary and possibly referendum processes (approximately 4 to 5 years). In parallel, the methodology for determining the necessary capacity requirements could be developed so that an appropriate and legally compliant capacity tender can then be prepared and implemented (approximately 1 year). At the project level, the planning and authorisation process follow, taking roughly 5 to 7 years, after which procurement and construction of the plant

would require an additional 3 to 4 years. Overall, even with the maximum possible parallelisation, and considering real process and market-related risks, this results in a plausible total timeframe of approximately 10 to 15 years from the creation of the funding basis to commissioning.

# Disclaimer and Bibliography

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