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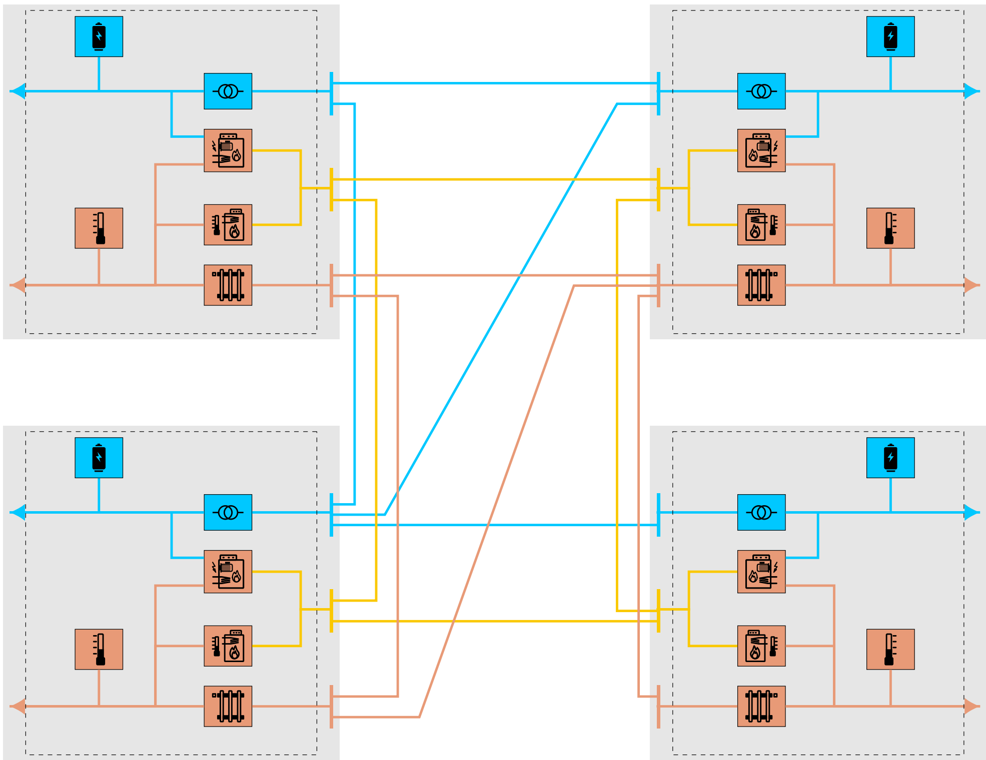
The Role of Gas and the Gas Infrastructure Within the Future Energy System - a Techno-Economic Assessment



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Summary

This project, focusing exclusively on the distribution and final consumption of energy carriers (i.e. bulk generation and transmission are out of the project scope), developed tools to model and quantify a coupled planning and operation of the electricity, gas and heating energy sectors (sector coupling). The results of this project assess to which extend sector coupling enables to better meet the challenges of the energy system of the future. At the same time, the followed "coupled" approach, allows to identify the potential value (or lack of value) of gas distribution infrastructure into the future energy system.

In this project, a set of potential future pathways are assessed in terms of their total cost for meeting the energy demand, served by a local utility (WWZ), over a 40-year time horizon. The assessment is performed by means of an optimisation tool for multi-carrier system planning that was developed as part of the project. The total cost consists of: (i) customer investments in heating technologies (see below) and rooftop PV; (ii) utility investments in expansion of the medium voltage (MV) electricity network batteries, electrolyzers and fuel cells; and (iii) utility operational cost, i.e. the cost for the utility to buy electricity and gas from the wholesale. Meeting a target for net-zero CO2 emissions was not considered in this project. Use of natural gas is assumed to be economically penalized by means of a CO2 tax, but otherwise acceptable. The sensitivity of the identified optimal (i.e. least-cost) solution to the value of the CO2 tax allows to identify the potential impact of the latter.

Under the wholesale electricity and natural gas price assumptions made in this study, it was found that if the CO2 tax increases to 210 CHF/ton, a pathway of full electrification at distribution level (dominated by heat pumps) can be up to 2-5% cheaper than a pathway in which gas maintains a considerable role in serving the end demand for heating. With the CO2 tax staying at today's value of 96 CHF/ton this cost difference diminishes. Worth noting is that such an electrification pathway requires considerable upfront investments by the households (to change their heating systems), while it might be difficult to materialize in practice due to limitations in the potential of air-sourced heat pumps (limitations which were not considered in this study). These investments are to be eventually paid back in a course of twenty years, but since the rate of return of those investments is relatively low, policy decisions might be required in order to prioritize such a pathway which results in lower CO2 emissions.

If easy access to a source of environmental heat is available, such as the Lake of Zug in this study, a heat pump-based district heating network leveraging this source can offer an additional small decrease in the total cost (3-5%). Contrary to a pathway where upfront investments are undertaken by the customers, district heating has the practical advantage that this decision is taken and implemented by the utility. On the other hand, not all utilities might have a favorable access to a source of environmental heat.

The MV electricity distribution networks considered in this study turned out to be capable of coping with a full electrification path. Network upgrades can still be required in order to maintain a high degree of redundancy and, hence, reliability. The potential cost of required investments in electricity distribution network upgrades is clearly not prohibiting. It does not make the electrification pathway uneconomic. In addition, upgrading the electricity network infrastructure is more economic than resorting into alternative options such as batteries or sector coupling, which might have a role only if electricity network upgrade is impossible for other practical (not strictly economic) reasons.

No need for maintaining the gas distribution network as an enabler of an electrification pathway was identified. However, the gas network is valuable if a pathway is followed where final gas demand remains considerable. The potential future role of gas distribution networks relies in serving final demand for gas, rather than acting as a technology which provides flexibility to the electric power system. For the wholesale electricity price considered in this study, it was found (by means of sensitivity analysis) that if the final cost of gas (i.e. gas price plus CO2 tax) remains below 70 CHF/MWh, then a pathway where gas is utilized for heating is cheaper than an electrification pathway. Worth noting is that this cutoff value can be also interpreted as the cost at which renewable synthetic gas needs to be produced to make a pathway where gas is utilized for heating cheaper than an electrification pathway, while also achieving the CO2 reduction targets.

All in all, this project justified the choice of performing an analysis considering the energy sectors in a coupled manner. This type of analysis is clearly the way forward into designing the Swiss energy system of the future. Investigating sector coupling at the transmission level is an important potential follow-up project, as it will allow to consider the correlation between electricity and gas prices, as well as to investigate the role of gas demand and transport infrastructure from the overall country energy system perspective.

Zusammenfassung

In diesem Projekt, das sich ausschliesslich auf die Verteilung und den Endverbrauch von Energieträgern konzentriert (d.h. das Erzeugung- und Übertragungssystem sind nicht Gegenstand des Projekts), wurden Werkzeuge zur Modellierung und Quantifizierung von Planung und Betrieb der gekoppelten Energiesektoren Strom, Gas und Wärme entwickelt (Sektorkopplung). Die Ergebnisse dieses Projekts bewerten, inwieweit die Sektorkopplung es ermöglicht, den Herausforderungen des Energiesystems der Zukunft besser zu begegnen. Gleichzeitig erlaubt der verfolgte "gekoppelte" Ansatz, den potenziellen Wert (oder fehlenden Wert) der Gasverteilungsinfrastruktur im zukünftigen Energiesystem zu identifizieren.

In diesem Projekt wird eine Reihe potenzieller zukünftiger Pfade hinsichtlich ihrer Gesamtkosten für die Deckung des Endenergiebedarfs, der von einem lokalen Versorgungsunternehmen (WWZ) bedient wird, über einen Zeithorizont von 40 Jahren bewertet. Die Bewertung erfolgt mit Hilfe eines Optimierungswerkzeugs für die Planung von Multi-Energiesystemen, das im Rahmen des Projekts entwickelt wurde. Die Gesamtkosten setzen sich zusammen aus: (i) Kundeninvestitionen in Heiztechnologien (siehe unten) und Photovoltaik; (ii) Investitionen des Versorgungsunternehmens in den Ausbau des Mittelspannungsstromnetzes (MV), Batterien, Elektrolyseure und Brennstoffzellen; und (iii) Betriebskosten des Versorgungsunternehmens, d. h. die Kosten für den Kauf von Strom und Gas vom Grosshandel. Die Einhaltung des Netto-Null-Zieles für CO2-Emissionen wurde in diesem Projekt nicht untersucht. Es wird angenommen, dass die Nutzung von Erdgas durch eine CO2-Steuer wirtschaftlich bestraft wird, aber ansonsten erlaubt ist. Die Sensitivität der identifizierten optimalen (d. h. kostengünstigsten) Lösung auf den Wert der CO2-Steuer ermöglicht es, die potenziellen Auswirkungen der letzteren zu ermitteln.

Wenn die CO2-Steuer auf 210 CHF/Tonne steigt, kann ein Weg der vollständigen Elektrifizierung auf der Verteilnetzebene (dominiert von Wärmepumpen) bis auf 2-5% billiger als ein Weg sein, bei dem Gas eine beträchtliche Rolle bei der Deckung der Endnachfrage nach Wärme behält. Wenn die CO2-Abgabe auf dem heutigen Wert von 96 CHF/Tonne bleibt, verringert sich dieser Kostenunterschied. Es ist anzumerken, dass ein solcher Elektrifizierungspfad beträchtliche Vorabinvestitionen der Haushalte für die Umstellung ihrer Heizsysteme erfordert, was in der Praxis aufgrund des begrenzten Potenzials von Luftwärmepumpen schwierig zu realisieren sein könnte (in der Studie wurde so eine Begrenzung nicht berücksichtigt). Diese Investitionen sollen sich schliesslich im Laufe von zwanzig Jahren amortisieren, aber da die Rendite dieser Investitionen relativ gering ist, könnten politische Entscheidungen erforderlich sein, um einen solchen Weg zu bevorzugen, der zu geringeren CO2-Emissionen führt.

Wenn ein einfacher Zugang zu einer Umweltwärmequelle vorhanden ist, wie z.B. der Zuger See in dieser Studie, kann ein Wärmepumpen-basiertes Fernwärmenetz, das diese Quelle nutzt, eine zusätzliche Senkung der Gesamtkosten (3-5%) bieten. Im Gegensatz zu einem Weg, bei dem die Vorabinvestitionen von den Kunden übernommen werden, hat Fernwärme den praktischen Vorteil, dass diese Entscheidung vom Versorgungsunternehmen getroffen und umgesetzt wird. Andererseits haben möglicherweise nicht alle Versorgungsunternehmen einen günstigen Zugang zu einer Umweltwärmequelle.

Die in dieser Studie betrachteten elektrischen MV-Verteilnetze erwiesen sich als fähig, einen vollständigen Elektrifizierungspfad zu bewältigen. Um ein hohes Mass an Redundanz und damit an Zuverlässigkeit aufrechtzuerhalten, kann dennoch ein Netzausbau erforderlich sein. Die potenziellen Kosten für die erforderlichen Investitionen in den Ausbau des Verteilnetzes sind eindeutig nicht prohibitiv und machen den Elektrifizierungspfad nicht unwirtschaftlich. Darüber hinaus ist der Ausbau des Stromnetzes wirtschaftlicher als alternative Optionen wie Batterien oder Sektorkopplung, die nur dann eine Rolle spielen könnten, wenn der Ausbau des Stromnetzes aus anderen praktischen (nicht rein wirtschaftlichen) Gründen unmöglich ist.

Es wurde keine Notwendigkeit für die Aufrechterhaltung des Gasverteilnetzes zur Ermöglichung eines Elektrifizierungspfades identifiziert. Das Gasnetz ist jedoch wertvoll, wenn ein Weg beschritten wird, bei dem der Gasendverbrauch beträchtlich bleibt. Die potenzielle künftige Rolle der Gasverteilnetze besteht darin, die Endnachfrage nach Gas zu bedienen, und nicht darin, als Technologie zu fungieren, die Flexibilität für das Stromsystem bietet. Für den in dieser Studie betrachteten Großhandelsstrompreis wurde (mittels Sensitivitätsanalyse) festgestellt, dass, wenn die Endkosten für Gas (d. h. Gaspreis plus CO2-Abgabe) unter 70 CHF/MWh bleiben, ein Pfad, bei dem Gas zum Heizen verwendet wird, günstiger ist als ein Elektrifizierungspfad. Erwähnenswert ist, dass dieser Wert auch als Kostendach für die Produktion von synthetischem Gas interpretiert werden kann, damit das Heizen mit synthetischem

Gas günstiger ist als ein Elektrifizierungspfad, während gleichzeitig die CO2-Reduktionsziele erreicht werden.

Alles in allem rechtfertigt dieses Projekt die Entscheidung, eine Analyse durchzuführen, die die Energiesektoren gekoppelt betrachtet. Diese Art der Analyse ist eindeutig der richtige Weg, um das Schweizer Energiesystem der Zukunft zu gestalten. Die Untersuchung der Sektorkopplung auf der Übertragungsebene ist ein wichtiges potenzielles Folgeprojekt, da dies die Betrachtung der Korrelation zwischen Strom- und Gaspreisen sowie die Untersuchung der Rolle der Gasnachfrage und der Transportinfrastruktur aus der Perspektive des gesamten Energiesystems des Landes ermöglicht.

Résumé

Ce projet, qui se concentre exclusivement sur la distribution et la consommation finale des ressources énergétiques (c'est-à-dire que la production et la transmission d'énergie sont hors du contenu du projet), a développé des outils pour modéliser et quantifier une planification et une exploitation couplées des secteurs de l'électricité, du gaz et du chauffage (couplage sectoriel). Les résultats de ce projet permettent d'évaluer dans quelle mesure le couplage sectoriel permet de mieux répondre aux défis du système énergétique du futur. En même temps, l'approche "couplée" suivie permet d'identifier la valeur potentielle (ou le manque de valeur) des infrastructures de distribution de gaz dans le futur système énergétique.

Dans ce projet, un ensemble de voies futures potentielles est évaluée en termes de coût total pour répondre à la demande énergétique finale, desservie par un opérateur énergétique (WWZ), sur un horizon de 40 ans. L'évaluation est réalisée à l'aide d'un outil d'optimisation pour la planification des systèmes multi-porteurs qui a été développé dans le cadre du projet. Le coût total se compose de: (i) les investissements des clients dans les technologies de chauffage (voir ci-dessous) et le photovoltaïque; (ii) les investissements de l'opérateur énergétique dans l'expansion du réseau moyenne tension (MT) : batteries, électrolyseurs et piles à combustible ; et (iii) le coût opérationnel de l'opérateur énergétique, c'est-à-dire le coût d'achat de l'électricité et du gaz. L'atteinte d'un objectif d'émissions nettes de CO2 n'a pas été envisagée dans ce projet. L'utilisation du gaz naturel est supposée économiquement pénalisée au moyen d'une taxe sur le CO2, mais acceptable par ailleurs. La sensibilité de la solution identifiée optimale (i.e. la moins coûteuse) à la valeur de la taxe CO2 permet d'identifier l'impact potentiel de cette dernière.

Selon les hypothèses de prix de gros de l'électricité et du gaz naturel formulées dans cette étude, il a été constaté que si la taxe sur le CO2 augmente à 210 CHF/tonne, une voie d'électrification totale au niveau de la distribution (dominée par les pompes à chaleur) peut être jusqu'à 2 à 5% moins chère qu'une voie dans laquelle le gaz conserve un rôle considérable pour servir la demande finale de chauffage. Si la taxe sur le CO2 reste à sa valeur actuelle de 96 CHF/tonne, cette différence de coût diminue. Il convient de noter qu'une telle voie d'électrification nécessite des investissements initiaux considérables de la part des ménages (pour changer leurs systèmes de chauffage), alors qu'elle pourrait être difficile à concrétiser en pratique en raison des limites du potentiel des pompes à chaleur aérothermiques (limitations qui n'ont pas été prises en compte dans cette étude). Ces investissements doivent être remboursés sur une période de vingt ans, mais comme le taux de rendement de ces investissements est relativement faible, des décisions politiques pourraient être nécessaires afin de donner la priorité à cette voie qui entraîne des émissions de CO2 plus faibles (sauf si le gaz naturel est remplacé par des gaz synthétiques renouvelables).

Si l'accès à une source de chaleur environnementale est facile, comme c'est le cas pour le lac de Zoug dans ce projet, un réseau de chauffage urbain basé sur une pompe à chaleur et exploitant cette source peut offrir une légère diminution supplémentaire du coût total (3-5%). Contrairement à un développement où les investissements initiaux sont pris en charge par les clients, le chauffage urbain présente l'avantage pratique que cette décision est prise et mise en œuvre par l'opérateur énergétique. D'un autre côté, tous les opérateurs énergétiques ne disposent pas forcément d'un accès favorable à une source de chaleur environnementale.

Les réseaux de distribution d'électricité MT considérés dans cette étude se sont avérés capables de faire face à un développement d'électrification complète. Des investissements dans le réseau peuvent encore être nécessaires pour maintenir un haut degré de redondance et, par conséquent, de fiabilité. Le coût potentiel des investissements nécessaires à la modernisation des réseaux de distribution d'électricité n'est évidemment pas prohibitif et ne rend pas la voie de l'électrification non rentable. En outre, la modernisation de l'infrastructure du réseau électrique est plus économique que le recours à des options alternatives telles que les batteries ou le couplage sectoriel, qui pourraient avoir un rôle uniquement si la modernisation du réseau électrique est impossible pour d'autres raisons pratiques (non strictement économiques).

Aucun besoin de maintenir le réseau de distribution de gaz comme faciliteur d'une voie d'électrification n'a été identifié. Cependant, le réseau de gaz est important si l'on suit une voie où la demande finale de gaz reste considérable. Le rôle potentiel futur des réseaux de distribution de gaz consiste à répondre à la demande finale de gaz, plutôt que d'agir comme une technologie qui apporte de la flexibilité au système électrique. Pour le prix de gros de l'électricité considéré dans cette étude, il a été constaté (au

moyen d'une analyse de sensibilité) que si le coût final du gaz (c'est-à-dire le prix du gaz plus la taxe sur le CO2) reste inférieur à 70 CHF/MWh, une voie où le gaz est utilisé pour le chauffage est moins chère qu'une voie d'électrification. Il convient de noter que cette valeur seuil peut également être interprétée comme le coût auquel le gaz synthétique renouvelable doit être produit pour créer une voie où le gaz est utilisé pour le chauffage moins cher qu'une voie d'électrification, tout en atteignant les objectifs de réduction de CO2.

Il ne fait pas partie de cette étude d'examiner le rôle de la demande de gaz et des infrastructures de transport dans la perspective du système énergétique global de la Suisse. Cependant, les résultats de cette étude suggèrent que le maintien d'un certain niveau de demande finale de gaz (et, par conséquent, de l'infrastructure de réseau de gaz nécessaire) pourrait avoir une valeur du point de vue du système global, car il permettra de lisser l'effet de la variabilité diurne et saisonnière de la production et de la demande d'électricité. Il semble que le couplage sectoriel soit plus important à étudier au niveau de la transmission.

Au total, ce projet a justifié le choix de réaliser une analyse considérant les filières énergétiques de manière couplée. Ce type d'analyse est clairement la voie à suivre pour concevoir le système énergétique suisse du futur. L'étude du couplage sectoriel au niveau du transport d'energie est un projet de suivi potentiel important, car elle permettra d'examiner la corrélation entre les prix de l'électricité et du gaz, ainsi que d'étudier le rôle de la demande de gaz et des infrastructures de transport du point de vue du système énergétique global du pays.

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1 Introduction

1.1 Project background

The ongoing decommissioning of nuclear power plants and the increasing penetration of, often decentralized, intermittent renewable energy sources is progressively transforming the Swiss electric power system. Power flow patterns become more variable, while there is an increase of power flow from distribution to transmission. Wholesale electricity prices are expected to become more variable, as the value of electric power will be varying in a diurnal and seasonal manner, depending on the net demand (or excess power production) of electric power. Flexibility will be increasingly valuable.

At the same time, the Swiss strategy for the energy transition, together with technology economics, motivate an increasing electrification of the end demand, especially end demand for space heating. As a result, final electricity demand is expected to increase. Noteworthy is the fact that this increase, instead of being proportionally distributed throughout the year, is expected to have a seasonal sign. On the other hand, building efficiency improvements, as well as the fact that heat pumps draw the larger share of the heat that they produce directly from the environment are probably mitigating the increase in final electricity demand.

In the context of such an "electrification pathway", the role of distribution gas infrastructure in the future is questionable. It is speculated that too little final demand for gas will remain to justify the business of maintaining and operating the gas distribution network.

On the other hand, since in many Swiss regions the gas distribution network is anyway there, there is increasing interest in investigating whether this infrastructure can have a value in the future as a means to provide flexibility required by the electric power system. A so-called "coupled" planning and operation of the energy sectors of electricity, gas and heating might allow to increase the overall energy system economics and efficiency.

As a matter of fact, energy networks, such as electricity and gas grids, have traditionally been planned and operated independent from each other. This project, focusing exclusively at the level of distribution, developed tools to model and quantify such a coupling of energy sectors. The results of this project assess to which extend sector coupling enables to better meet the challenges of the energy system of the future. At the same time, the followed "coupled" approach, allows to identify the potential value (or not) of gas distribution infrastructure into the overall future energy system.

1.2 Project objective

The main objectives of the project were:

1. to perform a technical, economic and policy assessment of the integrated planning and operation of energy supply systems with multiple energy carriers (i.e., power, gas and heating) for a Swiss municipal/cantonal utility in light of federal energy and climate policy objectives,
2. to explore dipping points and to show-case relevant interrelations: different economic and policy related boundary conditions will accordingly be envisaged and investigated to understand when, how and if local energy grids might be suitable for being designed and controlled as a coupled system,
3. to determine whether realistic conditions exist under which the coupling of carriers would actually

prove to be beneficial,

4. and finally, as a results of 1-3, to assess the role of gas infrastructure in the future energy system.

Clearly, per its objective, this project focused on the final demand for and the distribution of energy carriers, namely electricity, natural gas and hydrogen (only when blended with natural gas). Partly, also the generation of final energy carriers is included, particularly in terms of sector-coupling (e.g. generation of hydrogen through electrolysis and the production of heat through fuel cells). However, the bulk generation and transmission of those carriers has not been an endogenous part of the analysis. This is an important limitation of this study, as explained in Section 2.2.

1.3 Structure of this report

This report outlines the findings of the project "The Role of Gas and the Gas Infrastructure within the future Energy System - a Techno-Economic Assessment". The report is organized as follows.

Section 1 recalls the content of this study, summarizing the objective of the project. Section 2 outlines the utilized analysis framework and, importantly, the limitations of this study and how this study should be regarded as part of the broader Energy Strategy discussion. Section 3 summarizes all the scenarios, input parameters and values for sensitivity analysis that have been used in this project. Section 4 presents and comments on a comprehensive selection of the results obtained in this project. Finally, Section 5 summarizes the conclusions of this study.

2 Analysis framework

2.1 Methodology

The methodology can be divided into four phases:

1. In order to carry out the study, future scenarios have been defined. Since it is of specific interest to assess the effect of different energy policies, the scenarios are distinguished in terms of regulation, for which three variants are formulated, corresponding to the "Reference", "Electricity" and "Gas" scenarios.
2. Based on the defined scenarios, final energy demand for electricity and heat in the jurisdiction area of WWZ are determined in high temporal and spatial resolution based on a bottom-up future building stock model.
3. To perform the overall analysis at the final stage, a modelling and optimisation tool for multi-carrier system planning has been developed.
4. And finally, a techno-economic assessment of potential future options in electricity and gas distribution has been performed, considering a coupled planning and operation of WWZ network for given future demand, PV penetration, electricity and CO2 price, as well as technology cost scenarios.

In this project, the various potential future pathways are assessed in terms of their total cost for meeting the energy demand, served by a local utility (WWZ), over a 40-year time horizon. The total cost consists of:

1. customer investments in heating technologies (see below) and rooftop PV;
2. utility investments in electricity network expansion, batteries, electrolyzers and fuel cells;
3. utility operational cost, i.e. the cost for the utility to buy electricity and gas from the wholesale.

The considered energy demand consists of the direct demand for electricity and the demand for heating of residential and commercial buildings, located in the WWZ jurisdiction and connected to the electricity, gas and district heating networks of WWZ. Projections of the aforementioned end electricity and heating demand per building in the WWZ system have been estimated in five-year steps as part of this project (see Appendix 7). The industrial or large-service (such as hospitals) electricity demand (demand connected at Medium-Voltage (MV) level) as well as the demand for mobility/transportation have not been explicitly considered, but rather represented by additional electricity demand (fixed in all scenarios in the case of industrial/large-service demand, represented as additional electricity demand, standing for potential penetration of electric vehicles, in selected scenarios for the demand for mobility), as explained in Section 3.

From the energy demand viewpoint, the emphasis of the analysis performed in this project has clearly been on the building demand for space heating (and warm water). Starting from the heating technologies utilized in each of the WWZ buildings in 2015, different scenarios have been considered. The scenarios differ from each other in the penetration level (per 10-year step) of different technologies utilized to meet the end demand for heating. Four candidate technologies have been considered, per building:

1. Heat pumps (mostly air-sourced, but also water- and ground-sourced in buildings with such availability)

2. District heating by utility-owned medium-scale heat pumps (Circulago project)

3. Gas boilers

4. Fuel cells

Obviously, options 1 and 2 create final or secondary demand for electricity, while options 3 and 4 result in final demand for gas. Note that a by-product of option 4 is the production of electricity by the fuel cells (which, in this project, are assumed to be operated driven by the demand for heating).

Each such demand scenario consists of different rates at which the legacy heating technologies are replaced by combinations of the aforementioned 4 options. The total investment cost required to progressively perform the transition from the legacy fleet of heating technologies to the heating technologies of 2050 has been computed per demand scenario as explained in Section 3.1. Let us recall that this total cost is comprised of the customer investment cost and the utility investment cost to serve the resulting final demand for electricity and gas.

For every given demand scenario, the utility total cost for serving the end demand over a 40-year time horizon is computed by formulating and solving an optimization problem, presented in detail in Appendix 8, which simultaneously considers:

1. both energy carriers, i.e. electricity and gas,

2. the cost for purchasing electricity and natural gas from the wholesale,

3. the constraints imposed by the MV electricity distribution network,

4. investments in new infrastructure, namely upgrade of the electricity distribution network and utility-scale batteries, electrolyzers and fuel cells.

This "coupled optimization" approach allows to address one of the main project objectives (see Section 1), i.e. the "integrated planning and operation of energy supply systems with multiple energy carriers", allowing to assess "if local energy grids are suitable for being designed and operated as a coupled system" and to "determine whether realistic conditions exist under which the coupling of carriers would actually prove to be beneficial for the overall system".

It is important to emphasize here that the fact that the optimization solver has the option to invest in electrolyzers and fuel cells allows to couple the electricity and gas systems to the extend at which this minimizes the overall cost for the utility to meet the final demand. Also, the fact that the options of investing in batteries and/or electricity network upgrade are simultaneously considered allows to assess whether it is more economic to resolve electricity network bottlenecks by solely "electrical solutions" or by means of "sector coupling".

Finally, let us point out that the approach considered in this project is to perform extensive sensitivity analysis, i.e. solving the aforementioned optimization problem for various scenarios and different values of input parameters (such as infrastructure investment costs, electricity and gas prices, CO2 tax), thus allowing "to explore dipping points and to show-case relevant interrelations".

The assessment of the role of the gas distribution infrastructure is finally performed by comparing the total cost (i.e. customer + utility costs) of each of the various energy demand scenarios, allowing us to evaluate whether, from the overall cost perspective, it is desirable that customers maintain a demand for gas or that they rather progressively switch to heating systems which are based on electricity.

2.2 Limitations of this study

Objective of this section is to document the potential limitations of this study. Clearly, it is of paramount importance to take them into account in order to properly interpret and utilize the conclusions of this study, presented in Section 5. In the following, we list these potential limitations followed by a short comment on their role on the project conclusions.

2.2.1 Limitations related to the modelling of the electricity distribution network

1. The study was performed based on the MV electricity networks of a specific utility; WWZ.

   On the one hand, this is according to the project objective of performing the assessment "for a Swiss municipal/cantonal utility". On the other hand, this choice might potentially limit the generalizability of the analysis. As a matter of fact, it turned out, as shown in Section 4.1, that the WWZ networks have enough capacity to accommodate higher electricity demand. Hence, network congestion did not drive a need for new investments or sector coupling, as was originally assumed as a possibility to investigate. This observation is in line with the experience that the project team has from working with other Swiss distribution networks. It is important, however, to state that this might not be generalizing to entire Switzerland. For the sake of completeness of the study, we have performed an analysis of what could have been the cost of potential required network upgrades. The results are presented in Section 4.2.3. The conclusion is that the potential need for network upgrades does not constitute a significant economic hurdle against pursuing a strategy based on electrification of the demand for heating.

2. Only the medium voltage (MV) electricity network is considered.

   The low voltage (LV) network of WWZ was not available. Buildings have been assigned to MV nodes based on their geographic distance (each building assigned to the closest MV node). As a result, potential network limitations stemming from the inability of the LV network to cope with increased electricity demand or very high PV penetration levels are not considered. This limitation is not expected to affect the main conclusions of the study. Note however that, especially in less dense settlements, such as single-family house neighbourhoods or rural areas, LV network upgrades might be required in scenarios with high PV penetration.

2.2.2 Limitations related to the considered energy demand

1. No upper limit on the amount of air-sourced heat pumps which can pragmatically be installed in a district was considered.

   In a given district, especially if it is an urban one, it might not be technically and/or economically feasible for all buildings to be equipped with an air-sourced heat pump due to noise regulations and/or space limitations. There is a district-dependent "upper limit" on the amount of air-sourced heat pumps which can be installed at the typical installation cost of today. Exceeding this limit, even if technically feasible, will be considerably more expensive.

   Even though availability limits on the potential of water- and ground-sourced heat pumps were considered in this study, no limit was considered on the potential of air-sourced heat pumps. As a result, scenarios which assume a very high penetration of air-sourced heat pumps (namely, the "No Gas" scenario described in Sections 3.1 and 4.2) are probably underestimating the investment cost (in heat pump installations) that is required to reach them. In the context of this study, such a scenario should be rather seen as a scenario identifying the "boundary conditions", rather than a realistic potential way forward.

2. Demand for mobility is not explicitly modelled in this project.

   Potential final demand for electricity or gas stemming from future penetration of BEV (battery electric vehicles) or FCEV (fuel cell electric vehicles) is not considered in most of the considered demand scenarios (which, as explained in Section 2, consider future demand from electric appliances and future demand for space heating and warm water). However, as shown in Section 3.1, a few scenarios have been analyzed where a significant further increase in electricity demand is assumed (as part of a sensitivity analysis). Although these scenarios do not result from an analysis of the future mobility needs, they do however allow us to observe that even larger electricity demand does not alter the findings of this study.

3. New potential gas (methane or hydrogen) demand, stemming from non-electrifiable sectors, such as heavy-duty vehicles or process heating, has not been considered.

   Clearly, this is a limitation that should be taken into account when assessing the final findings. The reason is that presence of such final demand for gas might make the maintenance of, at least a limited part of, the gas infrastructure indispensable (or, at least, more valuable).

4. The instantaneous operation of heat pumps has been considered in an "averaged" manner.

   Instead of considering an on/off heat pump operation, it was assumed that each heat pump is operated such that it meets the demand for heating on an hourly basis in a smooth continuous manner. This assumption, made in the absence of more detailed modeling which would capture the on/off operation, is justified by the fact that buildings are anyway aggregated to MV nodes. The assumption is not expected to impact the findings of this study. A more detailed consideration of the real operation of heat pumps is performed in the project D-Flex, which is presently executed by ETHZ-FEN, funded by SGEN (Schweizerische Gesellschaft für Energie- und Netzforschung).

2.2.3 Limitations related to the consideration of transmission networks and wholesale markets

1. The electricity and gas transmission networks are not considered.

   Per its objective, this study focuses only on the level of electricity and gas distribution. It is therefore assumed that the utility can import electricity and gas from the respective transmission networks, up to an import limit dictated by the utility's capacity (of transformers and compression station). The effect of potential transmission level congestion is not considered. Also, the findings of the study consider only the distribution networks. They should not be interpreted as being reflected to the value of transmission-level network infrastructure and/or coupling of the energy sectors at the transmission-level. The value of transmission-level infrastructure has been out of the scope of this study. This is not, per se, a limitation of this study (given the study objective), but it should be emphasized to the reader that the study findings do not generalize to the value neither of the transmission-level infrastructure nor of transmission-level sector coupling.

2. The availability of electricity and gas at country (or European) level is not explicitly considered.

   This project studies only a specific region. Clearly, it is not an endogenous part of this study to model the evolution of the overall energy system and thus identify the cost of the energy carriers at wholesale level, i.e. the future wholesale electricity and gas prices. However, as explained in Section 2, the cost for the utility of purchasing electricity and gas depends on the assumed wholesale prices. As a result, the findings of this study strongly depend on the assumptions that are made regarding the "rest of the energy system", as these assumptions are, in turn, reflected to the wholesale electricity and gas prices at which the utility can purchase these energy carriers.

The approach that was followed in this project was to utilize, as the reference case, the electricity wholesale prices from another project, called REFLEX [1], in which TEP Energy was a partner, and the gas wholesale prices from the EU Reference Scenario [2]. Let us note that the REFLEX project has also used the EU Reference Scenario as a basis of fuel costs (such as gas prices) based on which the electricity prices were derived. Gas prices change in 10-year steps (but otherwise kept constant), while hourly resolution wholesale electricity prices are computed for the entire European system, hence also for Switzerland, based on a detailed analysis which relies on the combination of various models.

In order to somewhat contain the effect of not explicitly considering the wholesale-level energy system into this study, several wholesale electricity and gas price scenarios were formulated around the reference ones, as shown in Section 3.3. In this manner, we illustrate the dependence of the solutions identified in this study for the WWZ system on the wholesale prices at which the utility purchases the energy carriers. However, it is clearly out of the scope of this study to assess how these wholesale prices are expected to evolve in the future.

2.3 Connection to the broader energy strategy perspective

Since the initiation of this project, the Swiss Federal Council decided to set a target of net-zero CO2 emissions by 2050. In order to meet this target, natural gas (as any fossil fuel) needs to be eliminated from the Swiss energy mix. However, this study assumed that natural gas remains an option for meeting the end demand for energy. During the execution of the project, the project stakeholders decided that the project should stick to its original objective (i.e. consider natural gas as an acceptable option).

In this section, we present how the project approach and findings should be utilized in view of the net-zero CO2 emission strategy. Below, we itemize the relevant points.

1. Natural gas is progressively replaced by CO2-neutral methane, i.e. with biogas and/or with synthetic methane which has been produced by consumption of CO2-neutral power.

   Connection to this study: With the modeling detail followed in this project, the results of this study do not depend on whether the utility feeds its gas network with natural gas or any other methane gas. The analysis is not dependent on the "type of methane gas". It is, however, clearly dependent on the price at which the utility can purchase this gas at wholesale. In this study, the limited considered gas price scenarios were built around the EU reference scenario for the future natural gas price. The gas prices in a future system where gas is not natural gas but rather CO2-neutral methane might, in general, be very different from the gas price scenarios considered in this study.

   Regarding biogas, it is relevant to bring up the fact that the potential in Switzerland is limited (see, for example, the Energy Perspectives 2050+ [3]). So an assumption that enough biogas is available at any time might not hold.

   Regarding synthetic "green" methane, it is relevant to bring up the fact that, since the production of synthetic green methane is achieved by consuming electric power, it is reasonable to assume that in a future where the utilized methane gas is primarily green synthetic methane instead of natural gas, the dependence between electricity and gas price might be inverted: instead of the electricity price being primarily set by the gas price (since natural gas units are typically the marginally more expensive units setting the clearing price in electricity markets) it will be the gas price which will depend on the electricity price. It is beyond the scope of this project to assess the future electricity (and hence green methane) prices.

2. Hydrogen progressively gets established as a significant energy carrier.

   Connection to this study: The option of generating hydrogen and injecting it into the gas network is already considered in this study. The assumption is that the gas network is primarily utilized for methane gas, hence only up to 20% of its content is allowed to be hydrogen. Besides an indicative analysis was performed (see Section 4.11) where it was assumed that the entire gas distribution network is adapted to be able to transport solely locally produced hydrogen.

   A potential future setup where hydrogen is delivered via the gas transmission network and purchased by the utility at a wholesale price has not been part of this project. For the modelling detail followed in this study, such a setup where hydrogen is similar to the case where the gas transmission network is utilized to transport synthetic methane, with the following two differences: On one hand, hydrogen is expected to be cheaper (in CHF/MWh) than synthetic methane, since the latter (methane) is produced by the former (hydrogen) via a methanation step. On the other hand, capital investments in refurbishment of the network will be required in order to make it suitable for hydrogen, while synthetic methane can be transported by the existing gas network as is (see, for example, [4] and [5] for an estimation of the corresponding costs for converting the gas network to "purely hydrogen".

3 Scenarios and Parameters for sensitivity analysis

This section summarizes *all* the scenarios of demand, PV penetration and wholesale (electricity and natural gas) prices, input parameters (such as technology investment and O&M costs, technology efficiencies, CO2 tax etc.) and values for sensitivity analysis that have been used in this project. The demand and PV penetration scenarios presented in the sequel refer to the "Herti" distribution zone of the WWZ system. Herti, which covers the center of Zug, has the highest demand, while it also has access to the lake of Zug, which can be utilized as a source of heat for a heat-pump-based district heating network, as explained hereafter. The results presented in this report for Herti have been validated in the other WWZ networks

3.1 Demand scenarios

The evolution of the demand for heating and of the electricity demand for electric appliances and building technologies have been quantified as part of this study using a building stock model as presented in Appendix 7. Energy demand for heating in 2050 is projected to be ~30% lower than in 2015, while electricity demand of electric appliances is projected to increase by ~26% (compared to the 2015 value) until 2035 and then stabilize (and very slightly decrease) until 2050.

An assumption of this project is that oil-based heating (covering, in 2015, ~33% of the total demand for heating in WWZ) will progressively disappear, driven by regulation/policy and by individual customer decisions, while utilization of the environment as a source for heating, via air-, water- and ground-sourced heat pumps, will increase. This corresponds to a total of ~3'000 oil-based heating systems being converted in heat-pump-based ones within a period of 30 years. Precisely, it is assumed that buildings progressively utilize their full potential for water- and ground-sourced heat pumps (presented in Appendix 7), while the penetration of air-sourced heat pumps is differentiated according to the scenarios presented in the sequel. Finally, the existing district heating network (using wood as a fuel) is assumed to remain in operation until 2050, serving approximately the same demand as in 2015 (i.e. ~9.5% of the end demand for heating in Herti, which is the network with the higher utilization of district heating).

Based on the aforementioned analysis, two main demand scenarios were defined, differentiated by the respective penetration of air-sourced heat pumps versus gas boilers (let us recall that water-based and ground-based heat pumps are in all scenarios assumed to reach their maximum potential). Per scenario, demand for heating was transformed to final demand for electricity and gas according to the heat pump and gas boiler efficiencies used in this study[2]. Following, the buildings were assigned to low voltage (LV) nodes of the electricity networks, according to their geographical distance from the nodes [3]. Last, the LV nodes were aggregated to their corresponding medium voltage (MV) nodes (i.e. the MV side of the MV/LV transformer). This was done in order to somewhat cancel out the effect of the assignment of buildings to nodes solely according to their geographic distance.

Both scenarios follow the assumption that there is a trend towards increasing penetration of heat pumps. In the so-called "Reference" scenario heat pumps and gas boilers cover, respectively, ~79% and ~10% of end demand for heating in 2050, while in the so-called "Mild Gas" scenario they, respectively, cover ~68% and ~20% of the end demand for heating in 2050. In both scenarios, the demand of electric appliances is as identified using the building stock model of TEP Energy and presented in Appendix 7.

[2] The corresponding electricity demand was computed assuming the following COP values, taken from the data-package "decentralized energy conversion technologies" (2019-06-25) of the SCCER Joint Activity Scenario and Modeling, contact person being <andrew.bollinger@empa.ch>. (i) air-sourced HP: 2.773, ground-sourced HP: 3.383, and water-sourced HP: 3.078. Gas boiler efficiency was assumed to be 0.9.

[3] Geographic coordinates per building and per node were available, but not the actual connectivity of buildings to nodes.

Figure 3.1.1 shows, for the Reference demand scenario, how the end demand for heating in Herti is met using the various technologies in the four representative years that are used in this study.

In order to consider scenarios where customers switch to heat pumps at different paces, we also assume a "No Gas" demand scenario, in which no customer utilizes a gas boiler anymore by 2050, and a "Constant Gas" scenario, in which the heating demand covered using gas boilers remains practically constant from 2020 until 2050. Clearly, the "Reference" and "Mild Gas" demand scenarios, which have been extensively utilized in the sensitivity analyses presented in Section 4 (Results), lie between the "No Gas" and "Constant Gas" scenarios. It is important to emphasize that the "No Gas" is probably an extreme scenario, which is difficult to realize in practice (economically or even technically), since it excessively relies on a very high proliferation of building-level air-sourced heat pumps, which might not be feasible due to noise or space limitations as explained in 2.2, serving as a boundary condition case in our analysis.

In addition, two scenarios with increasing levels of electricity demand have been developed. These scenarios correspond to an even higher penetration of heat pumps and, importantly, to a higher "not-for-heating" demand for electricity. The motivation for creating these scenarios, which we denote as "Electric", and "Electric+", is twofold. First, the increased electricity demand assumed in these scenarios attempts to account for the lack of an explicit estimation of the future development of electric mobility, and, second, these scenarios allow us to further stress the electricity network, which in the "Reference" and "Mild Gas" scenarios is barely congested.

Finally, two pairs of demand scenarios have been developed in order to quantify the benefits and/or costs in case fuel cells or heat-pump-based district heating proliferate as means to meet the end demand for heating. All these scenarios are based on either the "Reference" or the "Mild Gas" demand scenarios, i.e. they do not modify the demand for electric appliances (which is higher in scenarios "Electric" and "Electric+"). They are the following:

1. Two "fuel cell" scenarios, namely "FC100" and "FC50", in which, starting by 2030, customers progressively install fuel cells in their buildings[4], dimensioned such that they can cover their heat demand. In our analysis, fuel cells are operated as combined heat and power sources, with their operation being driven by the heat demand. The electricity which is produced as a side result, either decreases the electricity demand of the building or it is fed back to the utility electricity distribution network. "FC100" assumes that all customers with access to the gas network install Fuel Cells by 2050 (in progressive steps, starting in 2030), while "FC50" assumes that half of these customers do so [5].

2. Two "lake water"-based district heating scenarios, implementing the planned Circulago project [7]. In both scenarios, it is assumed that the Circulago project is fully materialized by 2040. As it is not known which customers will opt for this options, we progressively assigned to Circulago all buildings which have access to the lake reservoir (according to the data by TEP Energy) and to the gas network (as these are the buildings with the higher demand density). Two "Circulago" scenarios were created, namely "Circulago-Ref" and "Circulago-Gas". The first was drawn from the "Reference" demand scenario and the second from the "Mild Gas" demand scenario [6].

All demand scenarios have a total annual industrial or large-service demand, directly connected to the MV electricity network, equal to 59 GWh in Herti, according to the snapshot provided by WWZ.

[4] The consideration of such scenarios was requested by the project stakeholders, for the sake of completeness of this study.

[5] According to Table 1 in [6], fuel cell total efficiency was assumed equal to 0.9 (split into 0.65 for heating and 0.25 for electricity).

[6] The COP of the heat pumps utilized as part of Circulago was assumed to be 2.9255, i.e. the average value between a water-sourced HP operating on warm water and an air-sourced HP.

Figure 3.1.2 presents the annual final electricity and gas demand for heating for each of the aforementioned scenarios, while Figure 3.1.3 (left) presents the annual final total electricity demand per scenario.

Per the analysis framework described in Section 2, for each demand scenario the costs that are required in order to materialize the corresponding investments in new heating technologies or in refurbishment of existing ones have been computed. In most cases, these costs are typically to be undertaken by the customer (if not subsidized). In the case of Circulago, these are investment costs to be undertaken by the utility.

These costs are shown in Figure 3.1.4 (left), based on the cost assumptinos presented in Table 3.1.1, for all the demand scenarios considered in this analysis. One can clearly observe that "Constant Gas" is the cheapest scenario to materialize from the upfront capital expenditure viewpoint, with a total cost of 171 million CHF. As a matter of fact, the more a scenario relies on air-sourced heat pumps, the higher the upfront costs are. For instance, the upfront investment cost of the "No-Gas" scenario (248 million CHF) is 45% higher than "Constant Gas". Scenario "Circulago-Ref" is 40% more expensive (340 million CHF), while the "Reference" scenario is 36% more expensive than "Constant Gas" (always, in terms of required upfront investments in dedicated technologies). Finally, one can see that the two "Fuel Cell" scenarios (FC50 and FC100) also require 32% and 34% higher upfront investments than "Constant Gas". They are, though, very slightly cheaper compared to the "Reference" scenario, on which they are based.

Clearly, the total cost associated with a choice of heating technology will also depend on the cost at which the energy carrier is provided. This "operation" cost is presented in the Results Section (4).

The customer investment costs related to their chosen heating technology have been computed based on the Energieheld Schweiz (www.energieheld.ch). Table 3.1.1 shows the utilized cost, per installed kW, for the refurbishment of an already existing heating system based on either a gas boiler or a heat pump and for the switch to a fuel cell system. It is assumed that a 10 kW gas boiler / heat pump is required for a household with a 20 MWh annual demand for heating. Like this, the total demand for heating is translated into a need for a gas boiler and/or heat pump capacity. Since all the demand scenarios start from an existing level of gas boiler installations, which is either reduced or kept constant, all gas boiler investment costs correspond to refurbishment costs. On the other hand, in all demand scenarios heat pump installed capacity is progressively increasing (and also refurbished, when a system reaches its end of life). The cost of switching from another heating system (such as gas or oil boiler-based) to a heat-pump-based has been assumed to be 1.2 times higher than the heat pump refurbishment cost [7]. Note that the utilized values are an overestimation of the expected total cost (in the entire district) for heating system upgrades, as they do not account for the economies of scale resulting in lower costs in large commercial or multi-family buildings.

Table 3.1.1: Heating system refurbishment cost (based on the Energieheld Schweiz)

Technology	CAPEX (CHF/kW)	interest rate	Lifetime	Annualized cost (CHF/kW)
Gas boiler (irrespective of year):	1’500	0.03	15	125.1
Heat pump (irrespective of year):	3’200	0.03	15	268.1
Fuel cell (in 2020):	5’000	0.03	20	336.1
Fuel cell (in 2030):	3’500	0.03	20	235.3
Fuel cell (in 2040):	2’750	0.03	20	184.8
Fuel cell (in 2050):	2’500	0.03	20	168.0

Sources: Energieheld Schweiz (www.energieheld.ch) and [9], [10]

[7] As more recent research results from the project Low-Invest-Cost-Solutions (LICS) [8] suggest add-on costs for switching heating system might be much more than 20%.

The cost of Circulago has been assumed to be 100 million CHF, according to [7]. Even though it is an investment performed by the utility, we include it in Figure 3.1.4, as it is an exogenous cost to the optimization problem that we use to perform the analysis.

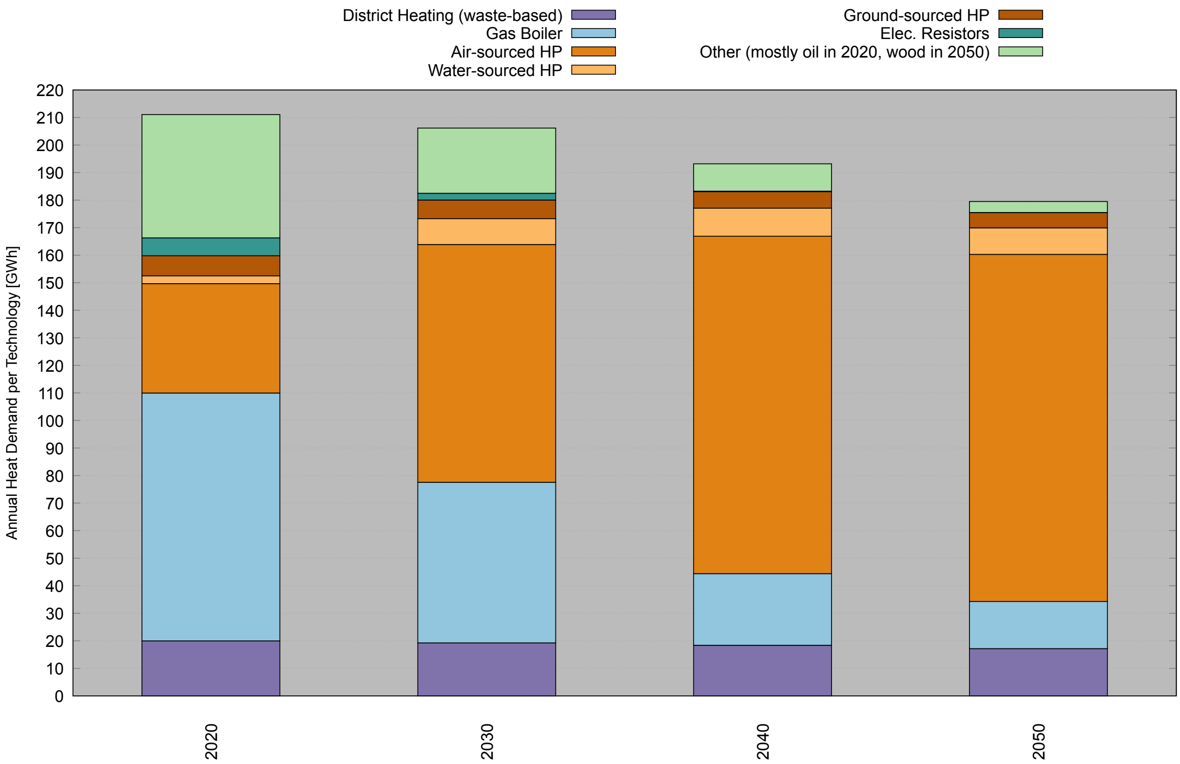

Figure 3.1.1: Reference demand scenario: Demand for heating covered by different technologies per representative year in Herti. Note that the Reference scenario does not consider the Circulago project, i.e. heat-pump-based district heating, which is investigated and quantified separately, as presented in Section 4.4.

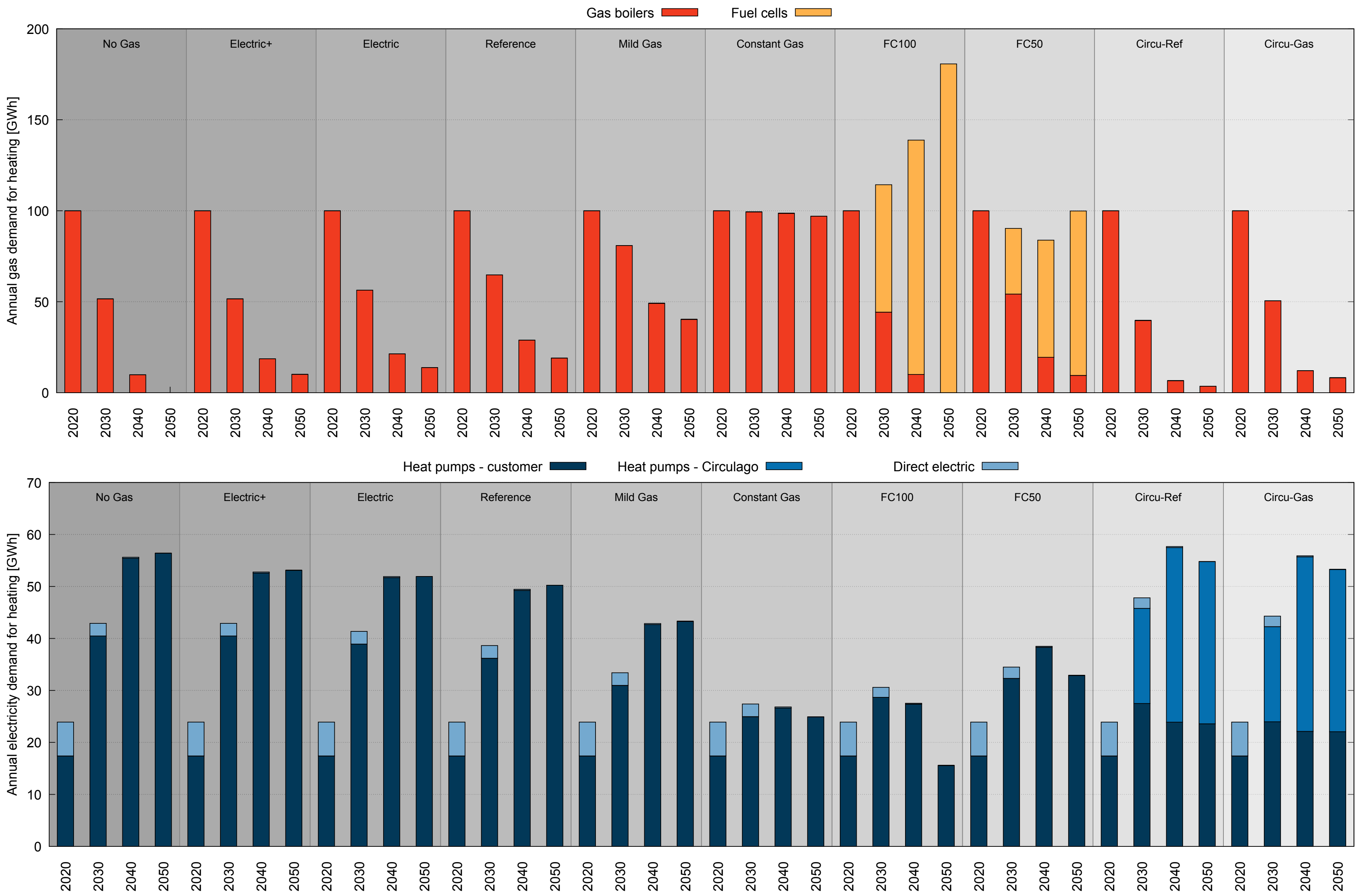

Figure 3.1.2: Annual final electricity and gas demand for heating in each of the considered scenarios. Demand for heating computed as presented in Appendix 7. The corresponding electricity demand for heating results by applying the scenario and efficiency assumptions described in Section 3.1

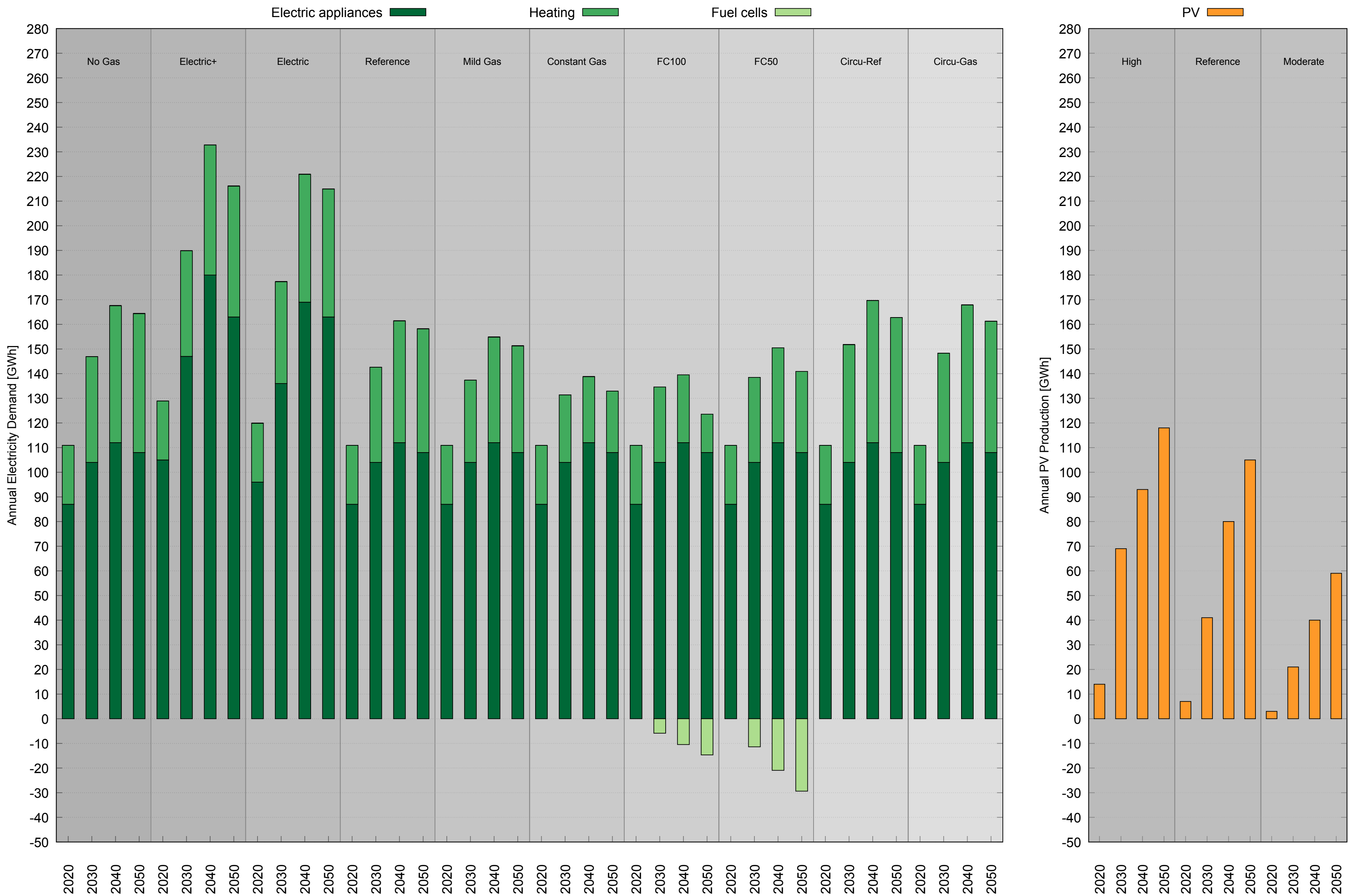

Figure 3.1.3: Annual total electricity demand (left) and annual total available PV production (right) per considered scenario. Reference values computed as presented in Appendix 7.

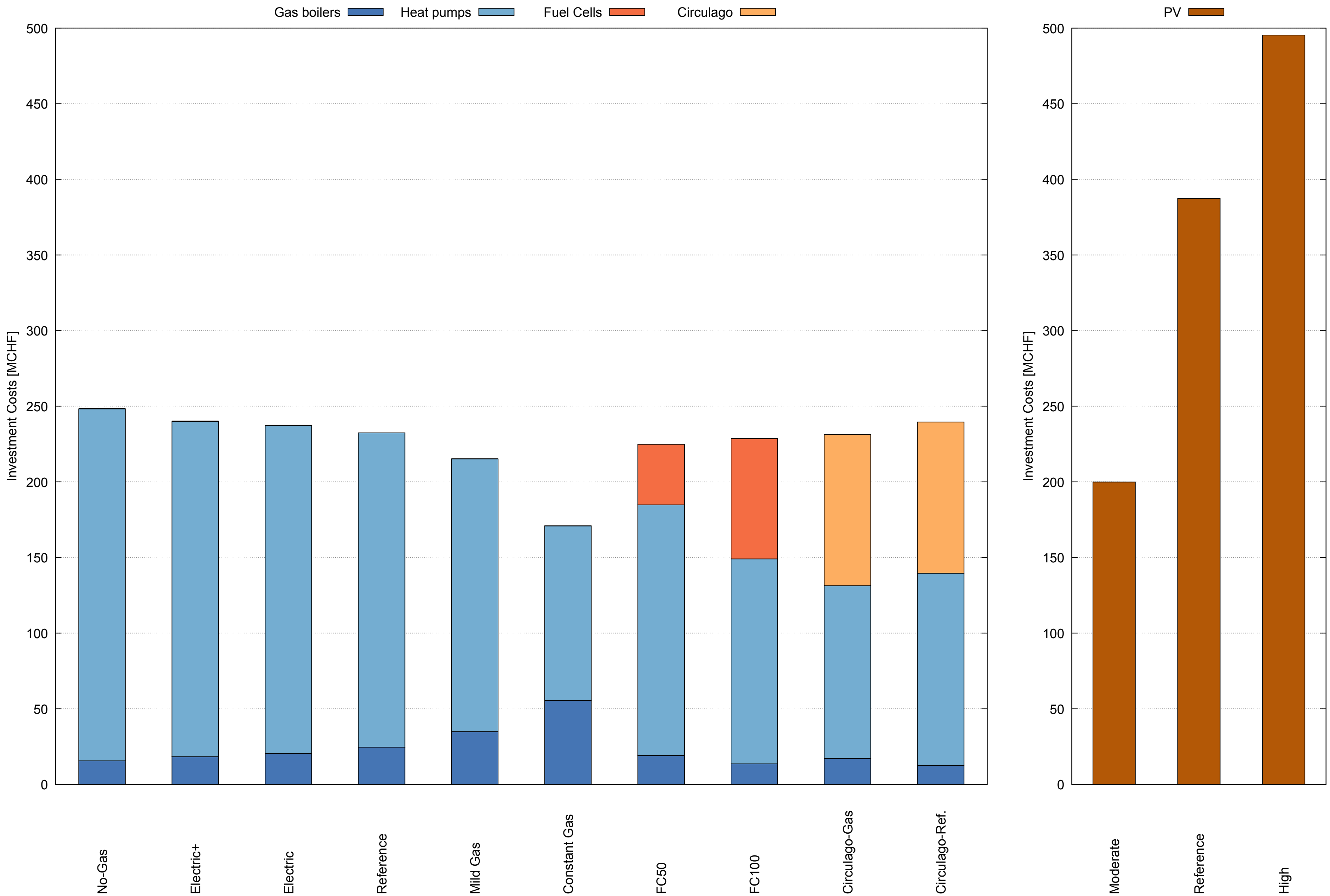

Figure 3.1.4: Total investments costs in heating technologies (left) and rooftop PV (right) that are required for the materialization of each of the considered scenarios, based on the cost assumptions presented in Sections 3.1 and 3.2.

3.2 PV penetration scenarios

The PV installation potential of each building was computed as shown in Appendix 7. Different PV penetration scenarios have been assumed, differentiated by the percentage of the total building potential that is covered by PVs. Tables 3.2.1 and 3.2.2 and Figure 3.1.3 (right) provide a summary of the scenarios.

We should note that they all adopt, to a larger or lesser extend, the path set by the Swiss Energy Strategy, in particular increasing penetration of distributed solar PV.

Similarly to the case of demand scenarios, the total cost required to perform the PV investments assumed in each scenario is given in Figure 3.1.4 (right). This cost was computed by assuming an installation cost equal to 2'500 CHF/kWp (Energieschweiz Solarrechner [8]), a lifetime equal to 25 years and an interest rate equal to 3%.

Table 3.2.1: PV penetration scenarios - % of total building PV potential reached

Scenario	**2020**	**2030**	**2040**	**2050**
Moderate:	2	15	30	45
Reference:	5	30	60	80
High:	10	50	70	90

Table 3.2.2: PV penetration scenarios - Annual available PV production (GWh)

Scenario	**2020**	**2030**	**2040**	**2050**
Moderate:	3	23	46	69
Reference:	8	47	93	123
High:	16	78	108	139

3.3 Energy and CO2 costs

The reference wholesale electricity price scenario is derived from the REFLEX project [1], which received funding from the European Union's Horizon 2020 research and innovation program with objective to analyse and evaluate the development towards a low-carbon energy system with focus on flexibility options in the EU. This was performed by means of an in-depth techno-economic assessment of various flexible low-carbon technologies with several energy system models. In REFLEX the models are soft-linked with one- and bidirectional data exchanges, and can be distinguished between demand projection models (FORECAST, eLOAD) and fundamental sectoral bottom-up energy system models (ASTRA, ELTRAMOD, TIMES-Heat) [1].

In REFLEX, a bottom-up electricity market model called ELTRAMOD (Electricity Transhipment Model) is used in order to represent the European electricity market. ELTRAMOD is a linear optimisation model which calculates the cost-minimal generation investments and dispatch in additional power plant capacities, storage facilities and power-to-x-technologies (i.e. power-to-heat, power-to-gas) [1]. Its geographical scope covers the member states of EU28, Norway, Switzerland and the Balkan countries. Each country is treated as one node with country specific hourly time series of electricity and heat demand as well as renewable feed-in. For a plurality of input parameters, such as country renewable energy source capacities, efficiency and ramp rates of generation and storage units, hourly prices for CO2 allowances and hourly wholesale fuel prices, ELTRAMOD computes, among others, the hourly wholesale electricity prices per country.

[8] https://www.energieschweiz.ch/page/de-ch/solarrechner/

In our analysis, we used the wholesale electricity price time-series for Switzerland resulting from the so-called "Mod-Res" scenario. This is a scenario which assumes a moderate expansion of renewable generation capacity across Europe (up to 55% in 2050). In REFLEX, the analysis resulting to wholesale electricity prices was performed using as an input the fossil fuel price projections from the European Reference Scenario 2016 [2]. We use the same source (i.e. the EU Reference scenario 2016) for the reference natural gas wholesale price (see Table 3.3.4).

The reference electricity price time-series has a relatively low variability (as quantified by the standard deviation) and a relatively high mean value (i.e. electricity becomes clearly more expensive in the future). However, according to several reports ([11],[12]), increasing wind and solar PV penetration is expected to increase the electricity price variability, with both price spikes and very low or even negative prices appearing considerably more often[9]. Also, they could lead to a decrease of the mean electricity price value. To account for these possibilities, we have considered several potential scenarios, consisting of combinations of higher standard deviation and lower mean value compared to the reference electricity price scenario. In addition, an electricity price scenario with even higher mean value has been considered. This was done in order to account for the fact that in REFLEX a somewhat lower CO2 tax value was used (150 €/ton in 2050) compared to the reference CO2 tax used in this project.

The mean value and the standard deviation of the electricity price scenarios utilized in this study are shown in Tables 3.3.1 and 3.3.2. By combining different values of mean value and standard deviation, a set of electricity price scenarios have been created, as shown in Table 3.3.3. These are the combinations for which results are shown in Section 4. The selection of which combinations to use was made while producing results, in an iterative manner, such that the most informative sensitivities are considered.

The reference CO2 scenario that we use in this study implements the Swiss CO2. In order to assess the impact of the CO2 tax, we also present results of scenarios where it is assumed that the CO2 tax stays equal to its 2020 value during the entire 40-year horizon (see Table 3.3.5).

Finally, we quantify the impact of the electricity and natural gas prices on the final results by performing sensitivity analysis. Hence, we introduce a "Low" and a "High" natural gas price scenario and a "High Std" and a "High Mean"[10] electricity price scenario.

Table 3.3.1: Wholesale electricity price scenarios: Mean annual electricity price (CHF/MWh)

Scenario	2020	2030	2040	2050
Reference:	41.6	71.9	83.0	80.6
Low Mean:	41.6	64.7	66.4	56.4
High Mean:	41.6	82.6	95.5	92.7

Reference scenario taken from REFLEX [1]

As explained in Section 2.3, a potential future where gas transmission networks carry net-zero CO2 biomethane, synthetic methane or hydrogen can be partially covered by this study, if the reader assumes that (a selection of) the final cost of gas shown in Table 3.3.6 corresponds to the cost of such "CO2-free" gas energy carriers. For the reader's reference, [13] projects the cost of synthetic fuels to be ~100 €/MWh in 2050, while [14] estimated a levelised cost of producing synthetic methane of 74 €/MWh. Cost of hydrogen is lower than synthetic methane, but gas networks need to be adapted accordingly.

[9] This is already observed today, for example in Germany in moments with low electricity demand and high wind availability.
[10] Used only for the sensitivity analysis comparing the relative impact of gas and electricity price.

Table 3.3.2: Wholesale electricity price scenarios: Standard deviation of annual electricity price (CHF/MWh)

Scenario	2020	2030	2040	2050
Reference:	10.8	11.3	16.0	22.4
Medium Std:	10.8	12.4	20.8	33.6
Medium-High Std:	10.8	12.4	22.4	39.2
High Std:	10.8	12.4	24.0	44.8
Super-High Std:	10.8	12.4	27.2	56.0

Reference scenario taken from REFLEX [1]

Table 3.3.3: Wholesale electricity price scenarios

Scenario acronym	Mean value	Standard deviation
pE-ref	Reference	Reference
pE-mS	Reference	Medium Std
pE-mhS	Reference	Medium-High Std
pE-hS	Reference	High Std
pE-shS	Reference	Super-High Std
pE-lM	Low Mean	Reference
pE-lMmS	Low Mean	Medium Std
pE-lMmhS	Low Mean	Medium-High Std
pE-lMhS	Low Mean	High Std
pE-lMshS	Low Mean	Super-High Std
pE-hM	High Mean	Reference

Reference scenarios taken from REFLEX [1]

Table 3.3.4: Wholesale natural gas price (CHF / MWh) scenarios

Scenario	2020	2030	2040	2050
Reference:	32	38	42	45
Low:	21.3	25.3	28	30
High:	52	62	69	73

Reference scenario taken from EU Ref. 2016 [2]

Table 3.3.5: CO2 tax (CHF / ton CO2) scenarios

Scenario	2020	2030	2040	2050
Reference:	96	210	210	210
Progressive:	96	130	170	210
Fixed:	96	96	96	96
No tax:	0	0	0	0

Reference scenario implements Swiss law

Table 3.3.6: Final price of natural gas (CHF /MWh) per combination of n. gas price and CO2 tax scenario

CO2 tax Scenario	Gas Price Scenario	2020	2030	2040	2050
Reference:	Reference:	51.1	80.1	84.4	86.8
Reference:	Low:	40.5	67.4	70.3	71.9
Reference:	High:	71.2	104	111	115
Fixed:	Reference:	51.1	57.3	61.6	64.0
Fixed:	Low:	40.5	44.6	47.5	49.1
Fixed:	High:	71.2	81.2	88.2	92.2

3.4 Technology scenarios

For the technologies of focus of the here-presented techno-economic assessment, a broader range of scenarios have been considered, thus allowing for sensitivity analysis to be performed. Tables 3.4.1, 3.4.2, 3.4.3 and 3.4.4 present the scenarios considered in the sensitivity analysis, while Table 3.4.5 the values of parameters of different technologies for which a sensitivity analysis has not been performed (but still used in the optimization model) are provided.

Let us draw the reader's attention to the fact that both the power capacity (i.e. the rate at which it can charge/discharge, expressed in kW) and the energy capacity (i.e. the amount of energy that it can store, expressed in kWh) are explicitly modeled. That is, instead of us deciding in advance on the battery's c-rate, we let the optimization problem identify it, hence achieving an optimal battery dimensioning.

In all cases, in order to compute the annualized cost of investing into a technology (i.e. grid expansion, battery, electrolyser or fuel cell), a cost of capital has been assumed, utilizing an interest rate equal to 3%, according to the following formula:

$$\text{Annualized Cost} = \text{Investment Cost} \times \frac{\text{interest rate} \times (1 + \text{interest rate})^{\text{technology Lifetime}}}{(1 + \text{interest rate})^{\text{technology Lifetime}} - 1} \qquad (1)$$

Table 3.4.1: Electrolyser CAPEX (CHF/kWe)

Scenario	2020	2030	2040	2050	Electrolyser type	Reference
AEC-Low:	550	385	302.5	261.25	Alkaline Electrolysis Cells	[15]
AEC-Ref:	1'210	779	550	440	Alkaline Electrolysis Cells	[15]
AEC-High:	1'540	1'100	880	770	Alkaline Electrolysis Cells	[15]
PEMEC-Ref:	2'120	1'450	1'015	800	Proto Exchange Membrane Electrolysis Cells	[15]

Table 3.4.2: Battery energy capacity CAPEX (CHF/kWh)

Scenario	2020	2030	2040	2050	Reference
Bat-Low:	300	200	150	100	[16]
Bat-Med:	450	350	275	300	[16]
Bat-Low-Med:	450	350	250	150	for sensitivity analysis
Bat-High:	600	500	400	300	[16]

Table 3.4.3: Fuel Cell CAPEX (CHF/kW)

Scenario	2020	2030	2040	2050	Reference
PAFC-Ref:	5'000	3'500	2'750	2'500	[9], [10]
PEFC-Ref:	16'000	12'500	8'000	4'000	[9], [10]
Cheap:	5'000	3'000	2'000	1'000	for sensitivity analysis
SuperCheap:	5'000	3'000	1'500	750	for sensitivity analysis

Table 3.4.4: Grid Expansion CAPEX (CHF/km for lines and CHF/unit for transformers)

Unit	**2020 / 2030 / 2040 / 2050**	**Reference**
Overhead line at MV:	55'000	[17]
Cable at MV:	140'000	[17]
Transformer (HV/MV)	2'100'000	[17]

Table 3.4.5: Technology parameters which were considered fixed in this study (no sensitivity analysis performed)

Parameter	**Unit**	**2020**	**2030**	**2040**	**2050**
CAPEX battery (power)	CHF/kW	160	140	120	110
OPEX electrolyser	CHF/kW		5% of CAPEX		
OPEX battery	CHF/kWh	6	6	6	6
OPEX fuel cell	CHF/kW	70	50	45	45
Lifetime electrolyser	years	20	20	20	20
Lifetime battery	years	20	20	20	20
Lifetime fuel cell	years	30	30	30	30
Lifetime cable	years	40	40	40	40
Lifetime overhead line	years	40	40	40	40
Efficiency electrolyser	-	0.8	0.8	0.8	0.8
Efficiency battery (charging)	-	0.922	0.922	0.922	0.922
Efficiency battery (discharging)	-	0.922	0.922	0.922	0.922
Efficiency fuel cell (heat)	-	0.6	0.6	0.6	0.6

4 Results

This section presents a comprehensive selection of the results obtained during this study. As explained in the previous section, we focus on the Herti network (serving the city of Zug), which, first, is the largest and, second, allows to analyze the value of lake-water-based district heating due to its proximity to the Lake of Zug. This choice does not alter the conclusions; very similar results have been obtained also for the other networks of the WWZ system.

The remainder of this "Results" section is structured as follows.

- First, the ability of the electricity network to accommodate the electricity demand and local PV power generation is investigated in Section 4.1. It is observed that electricity network congestion is not a limiting factor in the network utilized in this study.
- Then, the total cost analysis outlined in Section 2, performed for a selection of scenarios with varying degree of utilization of heat pumps vs. gas boilers, is presented in Section 4.2. It is observed that, for the boundary assumptions made in this study, higher proliferation of heat pumps (replacing gas boilers) results in a somewhat lower (2-5%) total cost, provided that the CO2 tax increases to 210 CHF/ton.
- Following this basic analysis, two specific cases are quantified in Sections 4.3 and 4.4; the option of the customers to install fuel cells to serve their end demand while producing electricity as a side result, and the option of resorting to a district heating system (Circulago) which is based on heat pumps and utilizes the Lake of Zug as the primary source of heating energy. It is observed that Circulago makes up an economically favorable option while fuel cells are shown to be an expensive option to meet the end demand for heating.
- The results of an extended sensitivity analysis are presented in Sections 4.7, 4.8, 4.9 and 4.10, where the boundary conditions for utility-scale electrolyzers and batteries to make up economically valuable investments are identified for a plurality of scenarios. It is observed that utility-scale fuel cells, operated as sources of local electric power by consuming gas, do not provide economic benefits in any of the scenarios considered in this study.
- Section 4.11 presents the results of an analysis which is performed to identify the potential value of utility-scale hydrogen storage. It is observed that hydrogen can be of value in a theoretical case where the utility stops purchasing gas from the wholesale level and, instead, relies on local hydrogen production to meet its demand for gas.
- Finally, the "Results" section closes, in Section 4.12, with an analysis of conditions under which performing electricity network upgrade is economically beneficial. This analysis is shown for the Altgass network (instead for Herti which is used in the rest of this report), as it is the only network of the WWZ system for which we have been able to identify scenarios for which (limited) network upgrade might have value.

4.1 Scenario analysis with respect to electricity network congestion

A common assumption regarding a potential future massively more electrified (in terms of demand) and renewable (in terms of power generation) energy system is that the existing electricity network might not be able to cope with the new power flow volumes and patterns, hence triggering the need for network upgrades or introduction of regulating technologies, such as batteries and sector coupling. In this section we investigate, for a selection of representative demand and PV penetration scenarios (see Section 3), whether the aforementioned assumption holds true for the main network utilized in this study: the Herti electricity distribution network, serving the city of Zug.

Note the following limitations of our analysis:

1. It is dependent on the allocation of building loads to network nodes, which, in our analysis, is inaccurate. Although effort has been made (as explained in Section 3.1) to avoid creating unrealistic cases, the results should be interpreted certain caution.
2. The HV transmission grid has been assumed as having infinite capacity to deliver the requested power or absorb the surplus from the distribution grid. Note, however, that the HV/MV transfers thermal limits *are* considered in the analysis.

For various combinations of demand and PV scenarios, the optimal planning problem has been solved, without allowing any investment in grid expansion or the other considered enabling technologies to be made. In order to ensure that no branch limit is violated at any hour step, the only options available to the solver have been PV curtailment and load shedding. Table 4.1.1 shows the results of this analysis.

Note that, for each network we consider a maximum acceptable branch load-ability limit up to 90% of its nominal capacity.

Table 4.1.1: Network feasibility analysis for Herti

PV scenario	Demand scenario	Total load shedding (MWh)	Total PV curtailment (MWh)	% of total available PV energy
High	Electric+	2.07	1’217	0.41%
High	Electric	0.18	1’218	0.41%
High	Reference	0.00	1’473	0.50%
Reference	Electric	0.18	836	0.36%
Reference	Reference	0.00	871	0.37%
Reference	Mild Gas	0.00	843	0.36%
Moderate	Reference	0.00	452	0.37%
Moderate	Mild Gas	0.00	452	0.37%

It can be observed that, in both networks, the demand can be practically always met in all scenarios: in the most "electrified" scenarios, a total load shedding equal to 2 MWh (which is required in 2040) is enough to avoid that no branch is loaded more than 90% of its nominal rating. Obtaining such an annual load reduction is easily achievable via a load flexibility mechanism.

One can see that a relatively small amount of PV available energy (up to 0.50%) would need to be curtailed. There are two independent reasons leading to PV curtailment:

1. Negative electricity price: Whenever the wholesale electricity price is negative and there is a surplus of PV production in the network, then it is worth curtailing the surplus instead of paying (due to negative price) in order to export it to the HV grid.

2. Congestion: If the flow in one or more branches reaches the 90% of the branch nominal rating, then PV is curtailed in order to maintain feasibility.

Tables 4.1.2 and 4.1.3 provide more insight into the reasons and the value of PV curtailment. Since, in all scenarios, PV curtailment happens in 2030 and 2050[11], the two tables refer to these two years. In both cases, the "Reference" electricity price scenario has been used.

Table 4.1.2: PV curtailment in 2030

PV scenario	**Demand scenario**	**PV curtailment due to negative price (MWh)**	**PV curtailment due to congestion (MWh)**	**Value of curtailed PV (CHF)**
High	Electric+	443	0	0
High	Electric	443	0	0
High	Reference	443	0	0
Reference	Electric	266	0	0
Reference	Reference	266	0	0
Reference	Mild Gas	266	0	0
Moderate	Reference	133	0	0
Moderate	Mild Gas	133	0	0

Table 4.1.3: PV curtailment in 2050

PV scenario	**Demand scenario**	**PV curtailment due to negative price (MWh)**	**PV curtailment due to congestion (MWh)**	**Value of annually curtailed PV (CHF)**
High	Electric+	638	136	8’886
High	Electric	638	136	8’937
High	Reference	638	392	25’778
Reference	Electric	567	2	145
Reference	Reference	567	38	2’468
Reference	Mild Gas	567	10	636
Moderate	Reference	319	0	0
Moderate	Mild Gas	319	0	0

Clearly, the majority of PV curtailment happens not due to network constraints but simply because it appears as a surplus in hours when it is not needed by the wholesale electricity system. During those hours of negative price, the utility is better of being a net consumer than a net producer of power.

One can also observe that, when PV penetration is extremely high (90% of the building potential in 2050 in the "High" PV penetration scenario), a clearly small percentage of the available PV energy (0.66-0.87% in 2050) needs to be curtailed due to electricity network congestion. The annual value of this "wasted" PV energy is in the order of a few thousands CHF in 2050 (the only year when PV power is curtailed due to congestion). Section 4.12 analyzes whether the value of the curtailed PV energy motivates investments in electricity network upgrades or the enabling technologies considered in this study (batteries, electrolyzers and fuel cells).

In any case, a clear observation of this study is that the end demand for energy can be met without network upgrades in *all* the demand and PV penetration scenarios that have been considered.

[11] In 2020 PV penetration is still too little, while 2040 is the year with the highest electricity demand, hence it turned out, that the net local production was not high enough for a curtailment to take place.

4.2 Total cost analysis of different paces of electrification pathways

This section makes up the core of the analysis performed in this study. It aims at addressing the core question of whether it is more beneficial to follow a pathway where electricity dominates as the energy carrier utilized to meet the end demand for space heating or a pathway in which gas maintains a role in this respect. The assessment is made based on the total cost (i.e. cost of customer and utility investments and cost of purchasing the required energy at wholesale, as explained in Section 2) of each pathway, defined as a scenario relating to the technologies utilized to meet the end demand for heating. The analysis is performed for selected scenarios on the evolution of the wholesale prices at which the utility can purchase electricity and gas.

We consider four demand scenarios, each corresponding to a different pace at which customers switch to heat pumps. Precisely, on one hand, we assume a "No Gas" demand scenario, in which no customer utilizes a gas boiler anymore by 2050, while on the other hand, we assume a "Constant Gas" scenario, in which the heating demand covered using gas boilers remains practically constant from 2020 until 2050. In between, we also assume the "Reference" and "Mild Gas" demand scenario. All scenarios are presented in 3.1. The reader is invited to recall the content of Figure 3.1.2, which shows the annual gas demand and annual electricity demand for heating in these demand scenarios. Let us also recall here one important limitation of this study: as explained in Section 2.2 it has been assumed that every building can convert its heating system to a system based on an air-sourced heat pump at the cost provided in Section 3.1 (in other words, no limits imposed by noise regulations or space limitations were considered). Note that this simplifying assumptions (justified by a lack of data at the period the analysis was performed) underestimates the total costs of the no gas scenario.

For each of the demand scenarios, we perform the 40-year-horizon investment and operational cost minimization described in Appendix 8, for the three PV penetration scenarios presented in Tables 3.2.1 and 3.2.2 and for the different values of the electricity price, gas price and CO2 tax presented in Tables 3.3.1, 3.3.2, 3.3.4, 3.3.5, 3.3.6. A graphical visualization of the various scenario combinations are shown in Figure 4.2.1.

4.2.1 Total cost per scenario

Figures 4.2.2, 4.2.3 present the results of the sensitivity analysis for varying gas price and CO2 tax, for the reference PV scenario and reference electricity price scenarios. The first figure shows the absolute total cost values, while the second figure shows the total cost increase/decrease expressed as a percentage over the total cost corresponding to the "No Gas" scenario. Hence, this figure shows how much overall cheaper or more expensive is to deviate from a policy of full heat-pump-based heating. Note that, as explained in Sections 2.2 and 3.1, in this study the investment cost of a "full heat-pump-based heating" policy is probably underestimated due to the assumption that any building's heating system can be converted to an air-sourced heat pump at the same costs (no add-on costs for noise protection or special design to overcome space limitation was considered).

Figures 4.2.4 and 4.2.5 present similar results, this time for varying electricity price and CO2 tax, for the reference PV and reference gas price scenarios.

It can be observed that the presence of the CO2 tax tends to make the total cost somewhat higher in the case where gas boilers are not replaced by heat pumps. However, the cost increase, covering a 40 year horizon, is in the order of a few percentage units (with the exception of the clearly unrealistic "High" gas price scenario). Noteworthy is the fact that the two pathways become equally expensive (for the utility and customer) if the CO2 tax stays at today's value of 96 CHF/ton. This shows that such a tax is a potentially strong instrument to motivate a transition away from natural-gas-based heating.

Even with a high-enough CO2 tax value (such as the "Reference" utilized in this study), it might be questionable whether such a small potential benefit in the long-term horizon might be enough to motivate customers to make upfront investments to replace their gas-boiler-based heating systems with heat-pump-based ones, as the expected benefits of such investments are small, while they depend on the future uncertainty. Let us also recall that, for some customers, air-sourced heat pumps might not be a practical option due to noise regulations or space limitations, as explained in Section 2.2. For those customers, a solution based on district heating might be a better option, as shown in Section 4.4.

An electrification pathway is not uneconomic. But, since it relies on upfront investments to be undertaken by end customers, motivation by policy-makers might by required, in order to achieve this less CO2-emitting pathway (see following subsection for a CO2-emissions analysis).

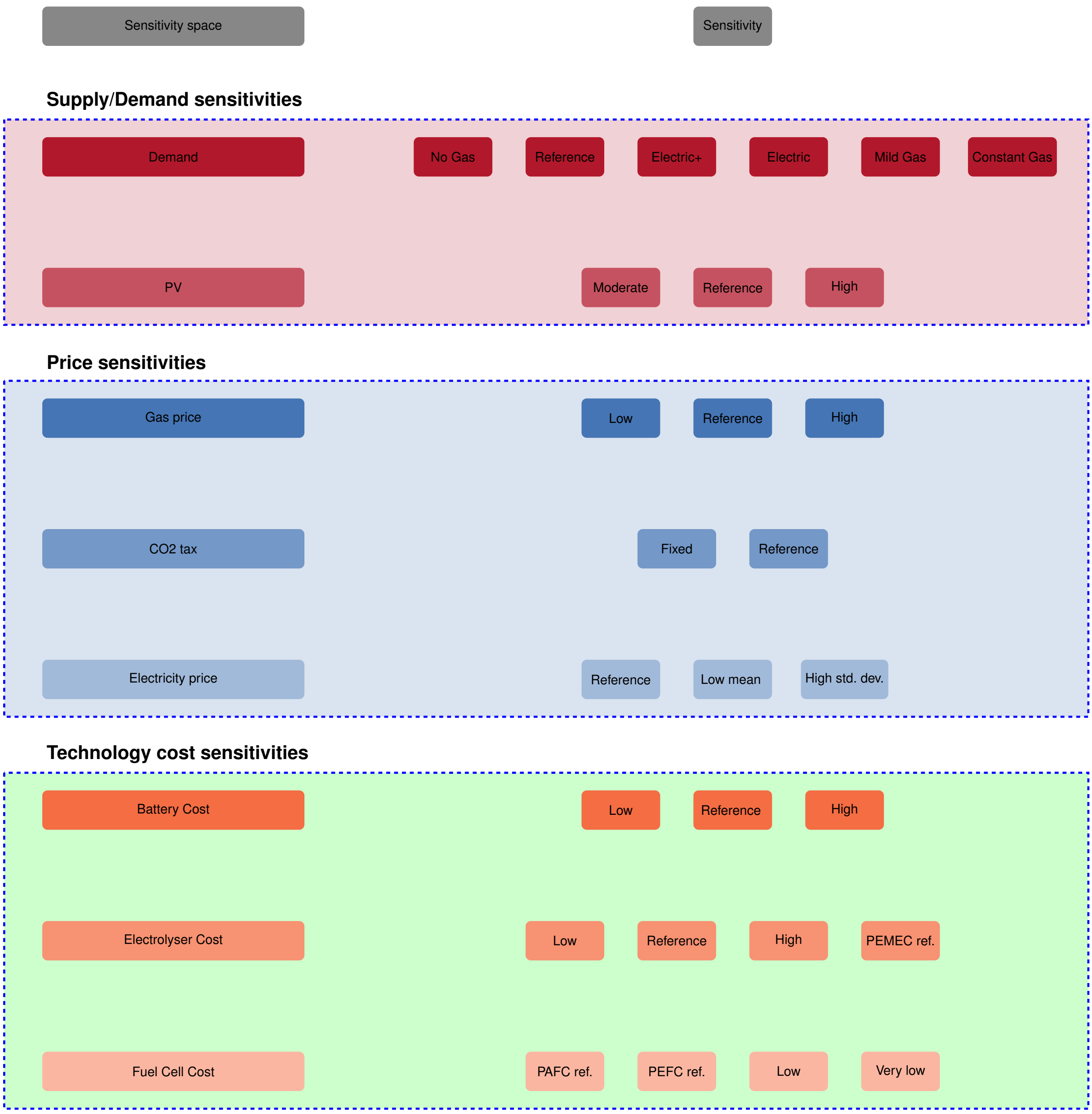

Figure 4.2.1: Various scenario combinations

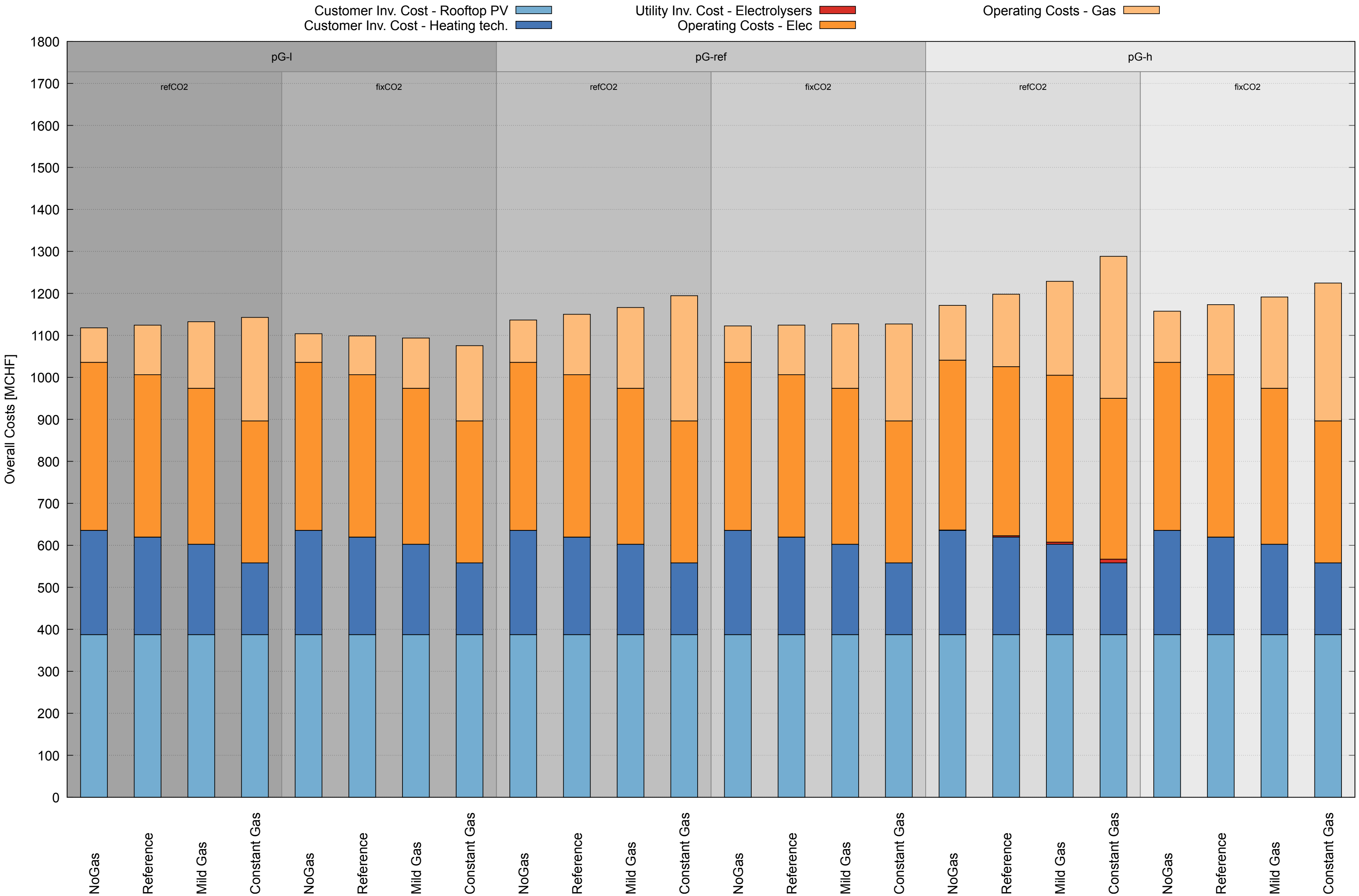

Figure 4.2.2: Total costs of the various scenarios for reference PV scenario and reference electricity price

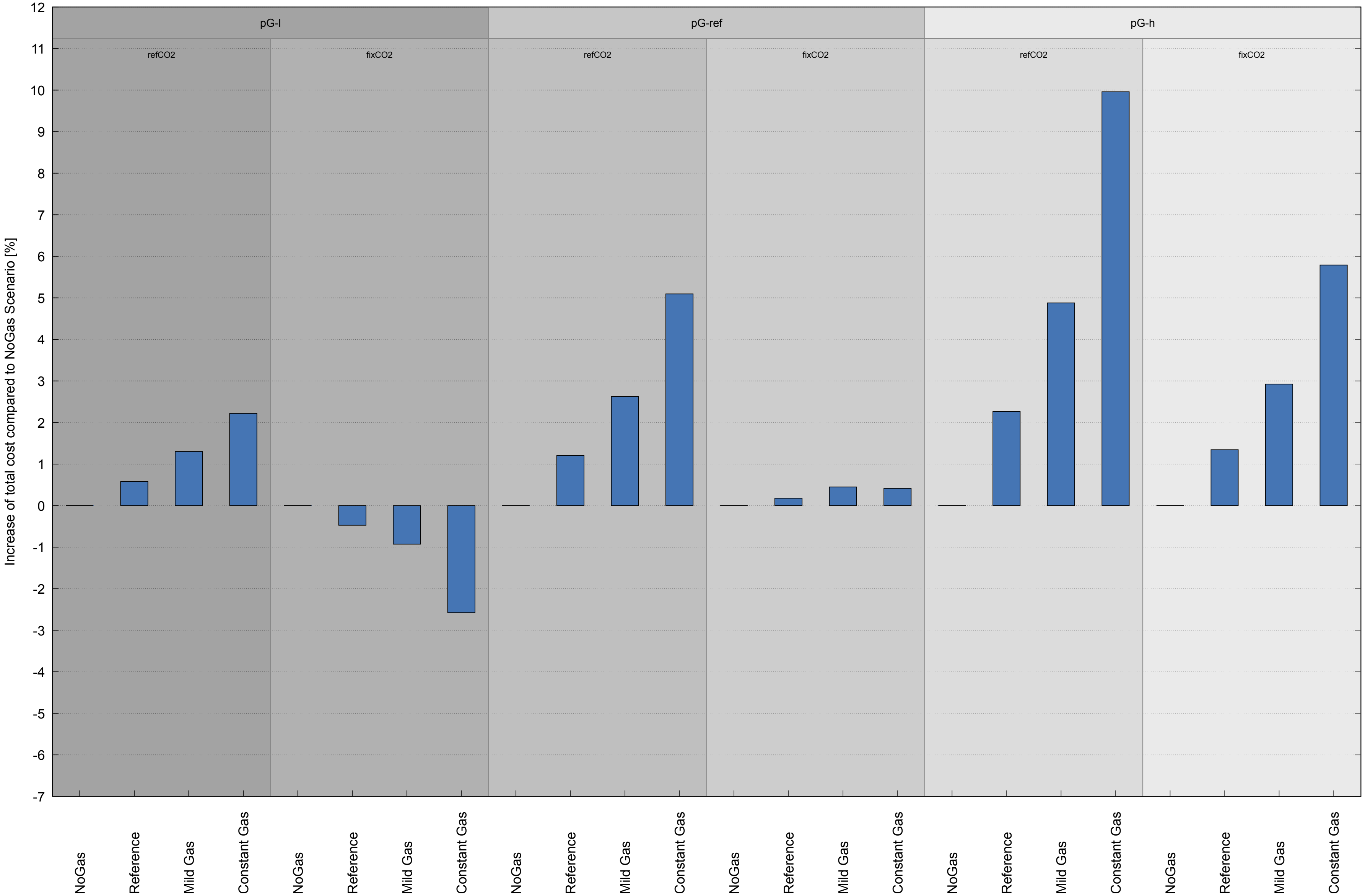

Figure 4.2.3: Total cost increase of the various scenarios compared to NoGas demand scenario for reference PV scenario and reference electricity price

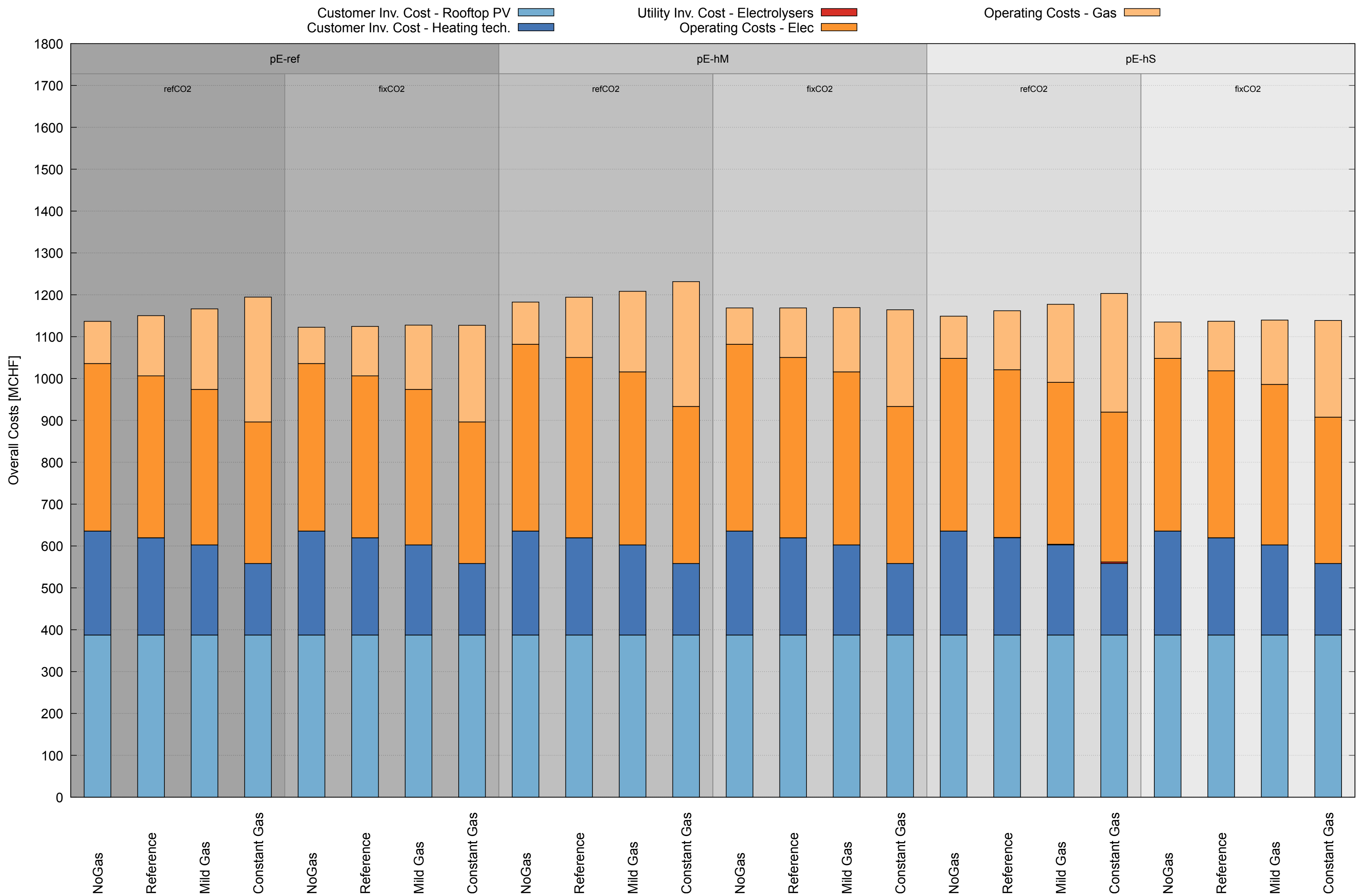

Figure 4.2.4: Total costs of the various scenarios for reference PV scenario and reference gas price

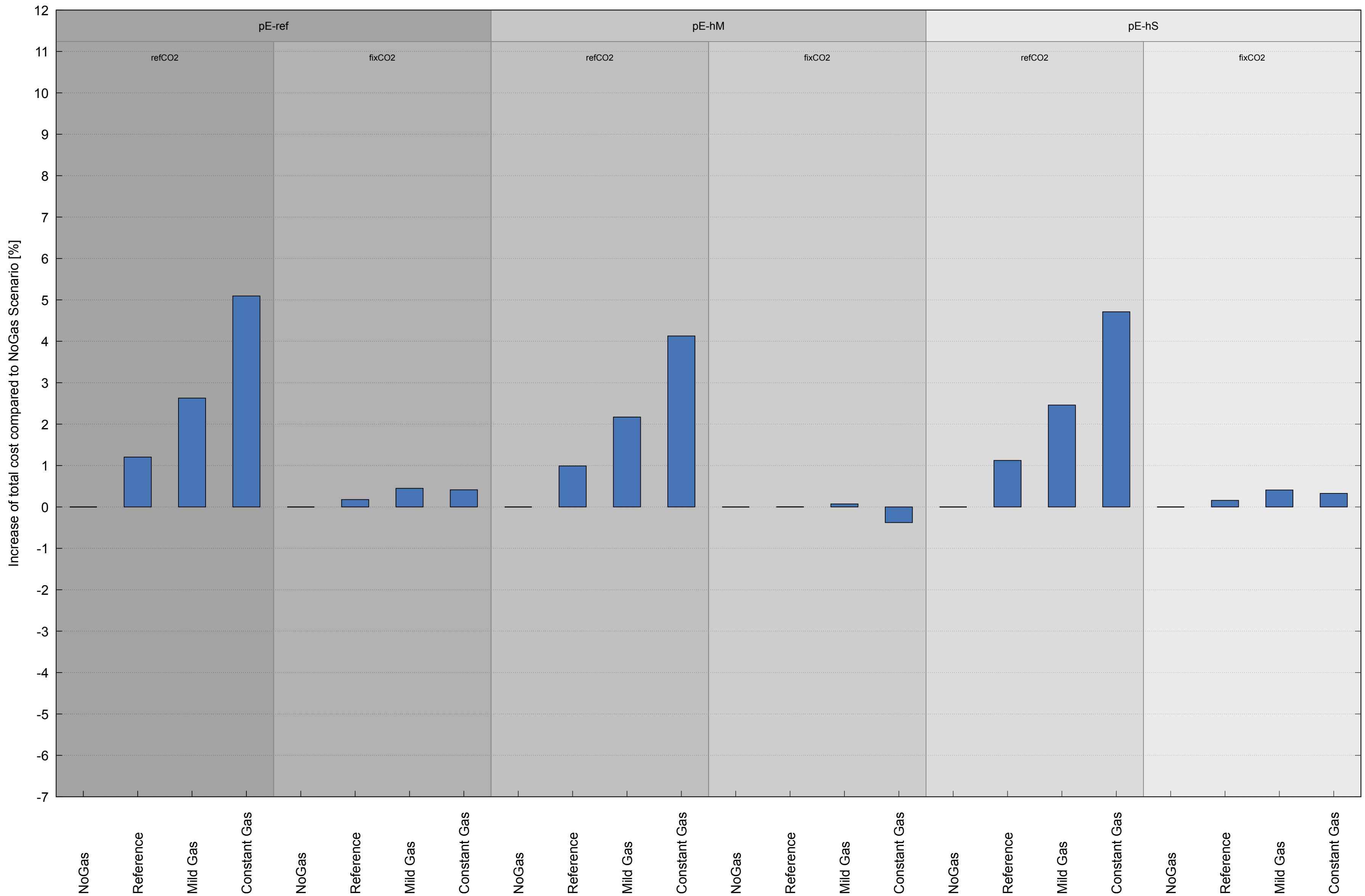

Figure 4.2.5: Total cost increase of the various scenarios compared to NoGas demand scenario for reference PV scenario and reference gas price

4.2.2 Impact on CO_2 emissions

In addition to the total cost of scenario, another attribute which is important for policy-making is the amount of resulting CO2 emissions. In this subsection, we quantify these emissions for a selection of the scenarios presented in Section 4.2.1.

To this purpose, for each representative year the corresponding annual CO2 emissions are computed as the summation of two terms: (i) the CO2 emitted by the gas boilers in the various buildings located in the district under consideration, and (ii) an approximate estimation of the CO2 emissions that are caused as a result of the electricity which the utility imports in order to satisfy the local net electricity demand.

In the case of gas boiler, the CO2 emissions per amount of consumed gas were taken from [18] (for the sake of simplicity, only new boilers are assumed) and shown in Table 4.2.1.

Table 4.2.1: CO2 emission factors of gas boilers (g CO2 per kWh of gas consumption)

Year:	2020	2030	2040	2050
Emissions factor (gCO2/kWh):	230	220	210	200

In the case of electricity imports, we estimate the CO2 emission factor corresponding to each hour of each considered year (i.e., 2020, 2030, 2040 and 2050) as follows. Based on the results of the REFLEX project for the country specific electricity supply mix [12], we calculate per country and hour, the technology-specific emissions in each hour of the year (Table 4.2.2 shows the utilized emission factors per generation technology [19]). These hourly emissions are then aggregated across all technologies and divided by the total amount of electricity generated during each hour to derive hourly emission factors, first per country and, eventually, for the entire EU28. That is, the "CO2 tag" that we assign to the electricity imports of WWZ during each hour equals the average CO2 emissions per kWh during that hour over the entire Europe.

Table 4.2.2: CO2 emission factors of electricity generation technologies (g CO2 per kWh of electricity production)

Type of generator	**Emission factor (gCO2/kWh)**
Natural Gas	202
Coal	337
Oil	276
Brown coal	400
CHP	167

Figure 4.2.6 shows the resulting hourly CO2 emission factors used in this study. Let us note that the REFLEX supply scenario is foreseeing an overall emission reduction of 80% by 2050 and is therefore not compliant with a full decarbonization scenario. However, it includes country specific technology pathways such as the phase-out of coal in Germany by 2036, amongst others [13].

[12] See https://data.esa2.eu/tree/reflex for the specific generation figures.
[13] See https://reflex-project.eu/public/paper-publications/ for more details on the REFLEX scenario design.

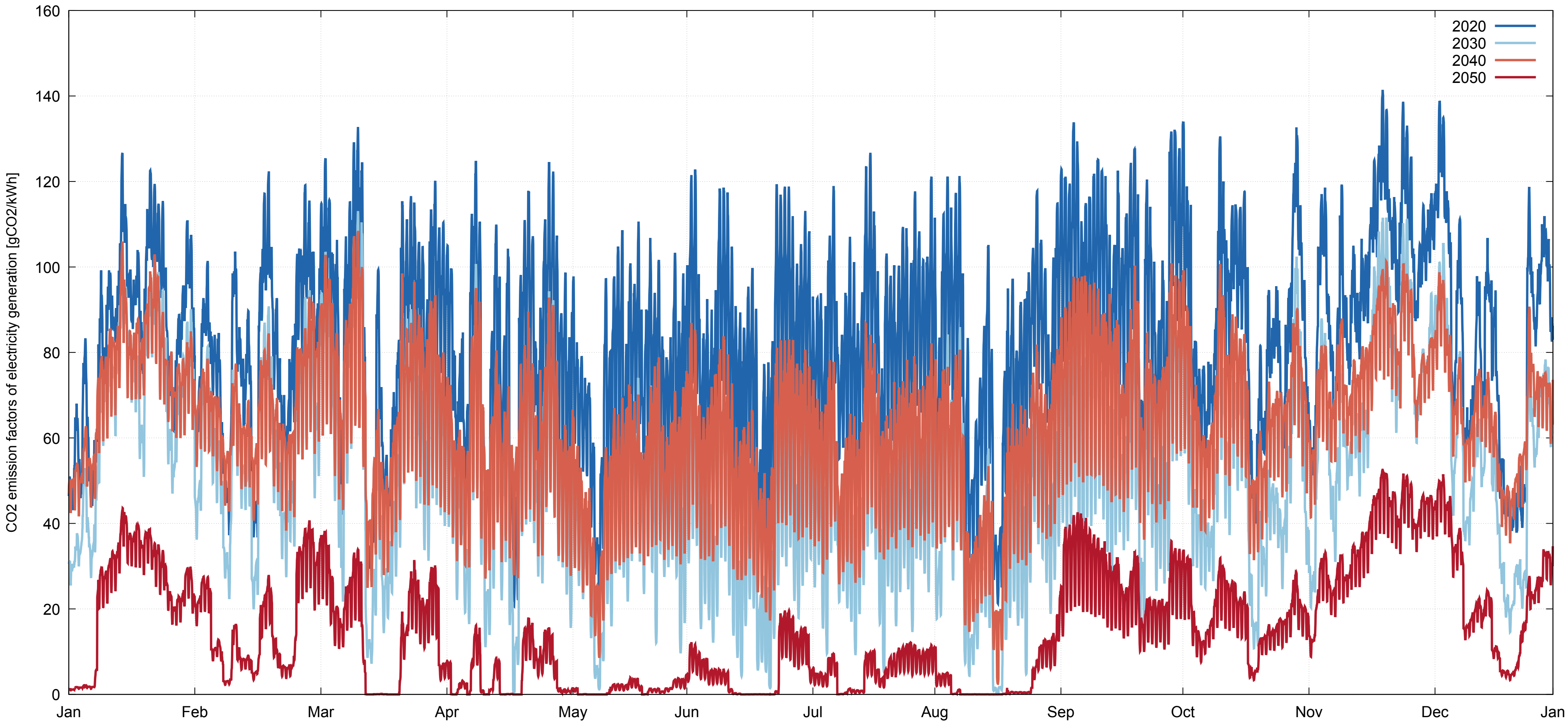

Figure 4.2.6: Average European hourly CO2 emission factors corresponding to electricity generation.

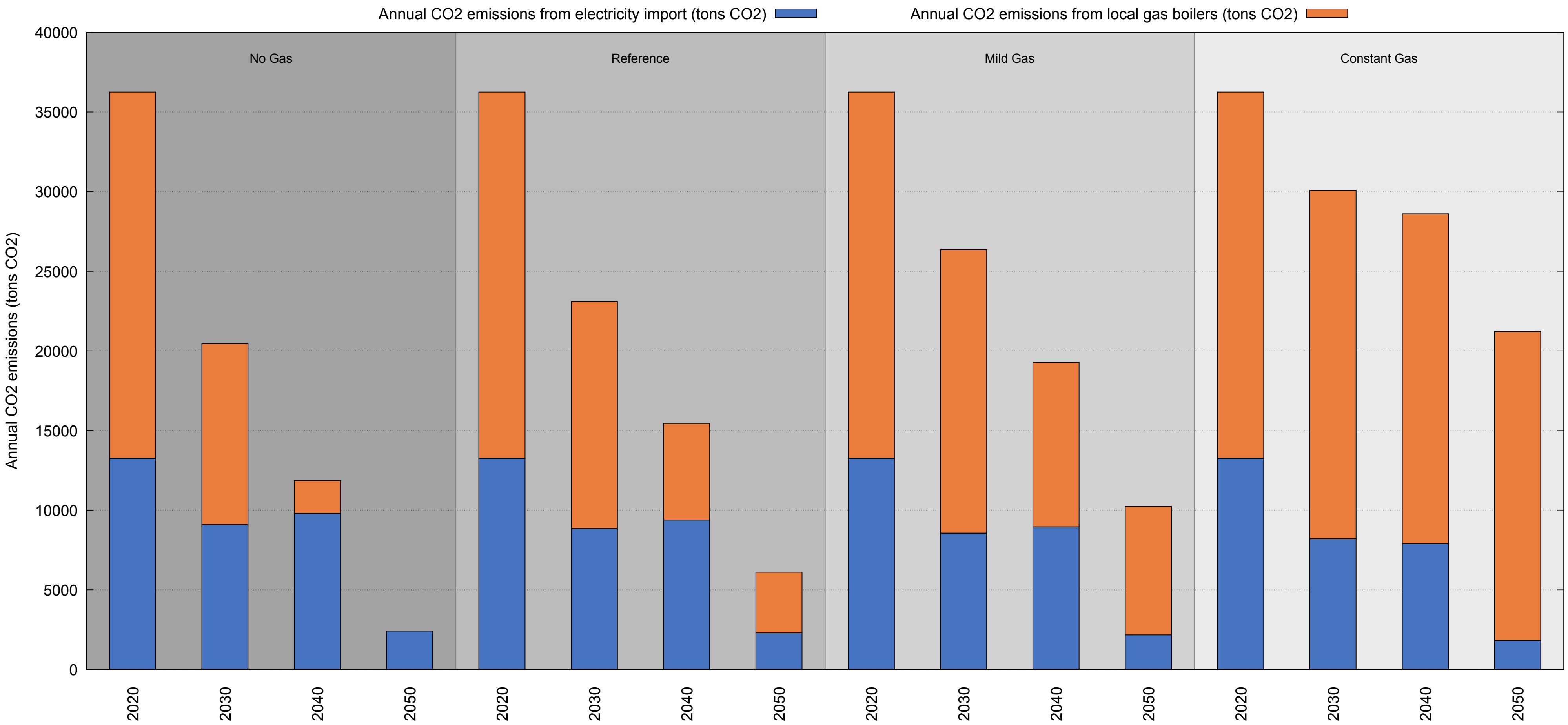

Figure 4.2.7: Annual CO2 emissions (tons CO2) per demand scenario. The reference PV, electricity price, gas price and CO2 tax scenarios are used.

Figure 4.2.7 shows the CO2 emission corresponding to each of the representative years for the four demand scenarios used in Section 4.2.1. The reference PV, electricity price, gas price and CO2 tax scenarios are used. As expected, it can be clearly observed that the higher the utilization of natural gas for heating, the higher the CO2 emissions. Table presents the total CO2 emissions over the entire 40-year period for each of the four scenarios[14], as well as the percentage increase in CO2 emissions as we move from the "No Gas" to the "Constant Gas" scenario.

Table 4.2.3: Total CO2 emissions per scenario [15]

Scenario:	No Gas	Reference	Mild Gas	Constant Gas
Total CO2 emissions (ton CO2):	709'749	809'091	921'076	1'161'529
Increase of CO2 emissions compared to the "No Gas" scenario (%):	-	14	30	64

One can clearly observe the beneficial impact, in terms of CO2 emissions, of moving from a natural-gas-based heating to an electric-heat-pump-based one. Let us recall again here that very high penetration of air-sourced heat pumps might be difficult (or expensive) to realize due to noise regulations and space limitations. Such constraints, as explained in Section 2.2 were not considered in this study.

4.2.3 Impact of potential electricity network congestion

Clearly, a typical reservation made with respect to future scenarios with high electrification of the end demand is that the present electricity distribution systems might not be dimensioned such that they can accommodate the resulting power delivery requirements.

As illustrated in Section 4.1, however, such a constraint is not applicable in the WWZ electricity networks which were utilized in the study. Even in scenarios with a very high increase of the final electricity demand, the resulting power flows were never high enough to stress the MV network beyond its thermal limits (of transformer, cables, and overhead lines). For example, Table 4.2.4 shows the peak electricity demand per year for the No-Gas demand scenario in the Herti distribution network. The two HV/MV transformers of this network allow for an import of 100 MW. One can clearly observe that the considered heat-pump-based scenarios do not bring the system even close to its electricity import limits [16].

Table 4.2.4: Peak electricity demand (MW) - "No Gas" demand scenario, Herti network

Scenario	2020	2030	2040	2050
No Gas:	40	52	57	54

Clearly, this observation is specific to the electricity distribution networks studied in this project. In order to quantify what could have been the impact of a potential need for network upgrades (the "need" might also be motivated by a desire from the utility to maintain a large reliability margin), in the following, we estimate the approximate cost if the utility was to upgrade **all** the components of the Herti electricity distribution network. The input information and the resulting costs are presented in Table 4.2.5, where the upgrade costs are according to [17].

The total cost to add an additional 50-MVA transformer and replace all overhead line and underground cables add up to approximately 20 million CHF. Clearly, this is a theoretical upper bound of the total cost,

[14] To do so, the emissions of each representative year are multiplied by a factor of 10.
[15] Including induced emissions by electricity consumption of heat pumps.
[16] Note that a full power flow analysis was performed. Here, we present the transformer loading only in order to provide "a feeling" to the reader.

Table 4.2.5: Potential network upgrade cost (for Herti 16.8 kV network)

Type of equipment	Unit cost (kCHF)	Amount of upgrade	Upgrade cost (kCHF)
50 MVA Transformer:	2'100 per unit	1 unit	2'100
Overhead line:	195 per km	20 km	1'000
Underground cable:	140 per km	115 km	16'000

not a realistic estimation of the costs of selected upgrades that might be required in certain distribution networks. With reference to Figures 4.2.2 and 4.2.4, one can observe that the total cost of each scenario, computed in a 40-year horizon, is between 1'100 and 1'200 million CHF.

Clearly, if the overall demand, supply, and price dynamics motivate higher electrification, potential required upgrades of the electricity distribution network cannot make up an economic hurdle to such a development. For example, let us quote that, in the case of the reference PV, reference electricity price, reference gas price, and reference CO2 tax scenario combination, the total cost difference between the "Constant Gas" and the "No Gas" scenarios equals 58 million CHF, i.e. three times the theoretical (and clearly exaggerated) maximum network upgrade investment.

4.2.4 Impact of cost of taking gas pipelines out-of-service/use

Finally, another relevant question raised in this project is to estimate the potential cost of making the gas network permanently inactive in case gas is not anymore used as a distribution-level energy carrier. In order to perform an approximate estimation of such costs, we use the cost information from reference [20], where gas pipeline inactivation works are categorized into three types.

1. *Dismantling*, where the underground gas pipeline is taken out and the land is returned to its original use. This happens in 5% of the cases and costs approximately 800 €/m.
2. *Damming and sealing*, where the pipeline remains in the ground but it is rendered inert and filled with fillers. This happens in 30 % of the cases and costs approximately 200 €/m.
3. *Sealing*, where the pipeline is rendered inert and remains as a cavity in the ground. This happens in 65 % of the cases and costs approximately 20 €/m.

Applying the aforementioned data to the Herti gas distribution network, which has a length of approximately 80 km, results in a total cost of rendering the pipelines inactive less than 10 million CHF.

Clearly, this is a cost which can be justified in case there are economics (or political/societal will) that drift the energy demand away from the utilization of gas.

4.3 Total cost analysis of alternative pathways: Customer-level fuel cells, utilized as combined heat and power sources

The objective of this and the following sections is to quantify the value of two specific pathways for meeting the end demand for space heating. In this section, we quantify the impact of a non-negligible amount of customers choosing to install fuel cell systems.

As explained in Section 3, these fuel cells are consuming gas (natural gas or hydrogen) drawn from the gas network and produce heat and power. Their operation is driven by the demand for heating, while power is a by-product which either reduces the local electricity consumption of the building, or, in case of excess power generation, it is injected to the electricity network (similarly to PV power). The fuel cell efficiency is assumed to equal 0.9; split into a gas-to-heat ratio equal to 0.65 and a gas-to-power ratio equal to 0.25. Two such scenarios are considered, "FC50" and "FC100", as explained in Section 3. Clearly, these are scenarios with considerable demand for gas (n. gas and/or H2) as shown in Figure 3.1.2. Contrary to the other demand scenarios considered so far in this project, in these two FC scenarios demand for gas remains considerably high (FC50) or even increases (FC100) until 2050.

Figures 4.3.1, 4.3.3 and 4.3.5 present the resulting total cost, after performing the optimization for selected combinations of PV penetration, gas price, electricity price and CO2 tax scenarios. In all cases, the "Bat-Med", "AEC-Ref" and "PAFC-Ref" scenarios are used.

One can observe that, for the electricity price, natural gas price and CO2 tax scenarios considered in this analysis, higher reliance in fuel cells (which practically corresponds to lower penetration of air-source heat pumps) results into higher total operating costs. The reason is that the cost of purchasing natural gas, together with the CO2 tax, are high enough to make electricity a more economic energy carrier to meet the heat demand. This observation was already made for gas boilers in Section 4.2. In comparison to gas boilers, fuel cells allow for somewhat lower operating cost, since they produce electricity as a side-result. But, on the other hand, fuel cell are clearly more expensive to install (see Table 3.1.1. As a result, resorting to fuel cells is not a cheaper option for the customer compared to heat pumps. Noteworthy is the fact that even in the case of the "Low" gas price and "Fixed" CO2 tax scenarios, the "Reference" demand scenario (i.e. without use of fuel cells) is still cheaper.

All in all, it seems that the utilization of fuel cells for local space heating is not an economically beneficial pathway. As a matter of fact, Figures 4.3.2, 4.3.4 and 4.3.6 show the percentage increase in total cost with respect to the "Reference" demand scenario.

One can observe in Figures 4.3.1, 4.3.3 and 4.3.5 that, in some cases, the optimal solution includes a certain utility-scale investment in electrolyzer capacity. Figures 4.3.1, 4.3.3 and 4.3.5 shows the amount of new electrolyzer capacity. On can clearly observe that the solver identifies as an optimal choice for the utility to build electrolyzers when gas demand increases and the final cost of gas (i.e. wholesale gas price plus CO2 tax) increases. The reason why electrolyser capacity is built, is in order to satisfy the gas demand by consuming electricity (instead of purchasing natural gas from wholesale) when electricity is cheap and/or abundant. Also, increased electricity price variability motivates larger amounts of electrolyzer capacity because, for a given mean value, higher variability means that there are more frequent and more intense low-electricity-price hours. It is exactly during these hours that the electrolyser has the higher value, since then it can produce H2-gas which is considerable cheaper than natural gas. A more detailed sensitivity analysis on the boundary conditions under which investing in electrolyzers has value is presented in Section 4.7.

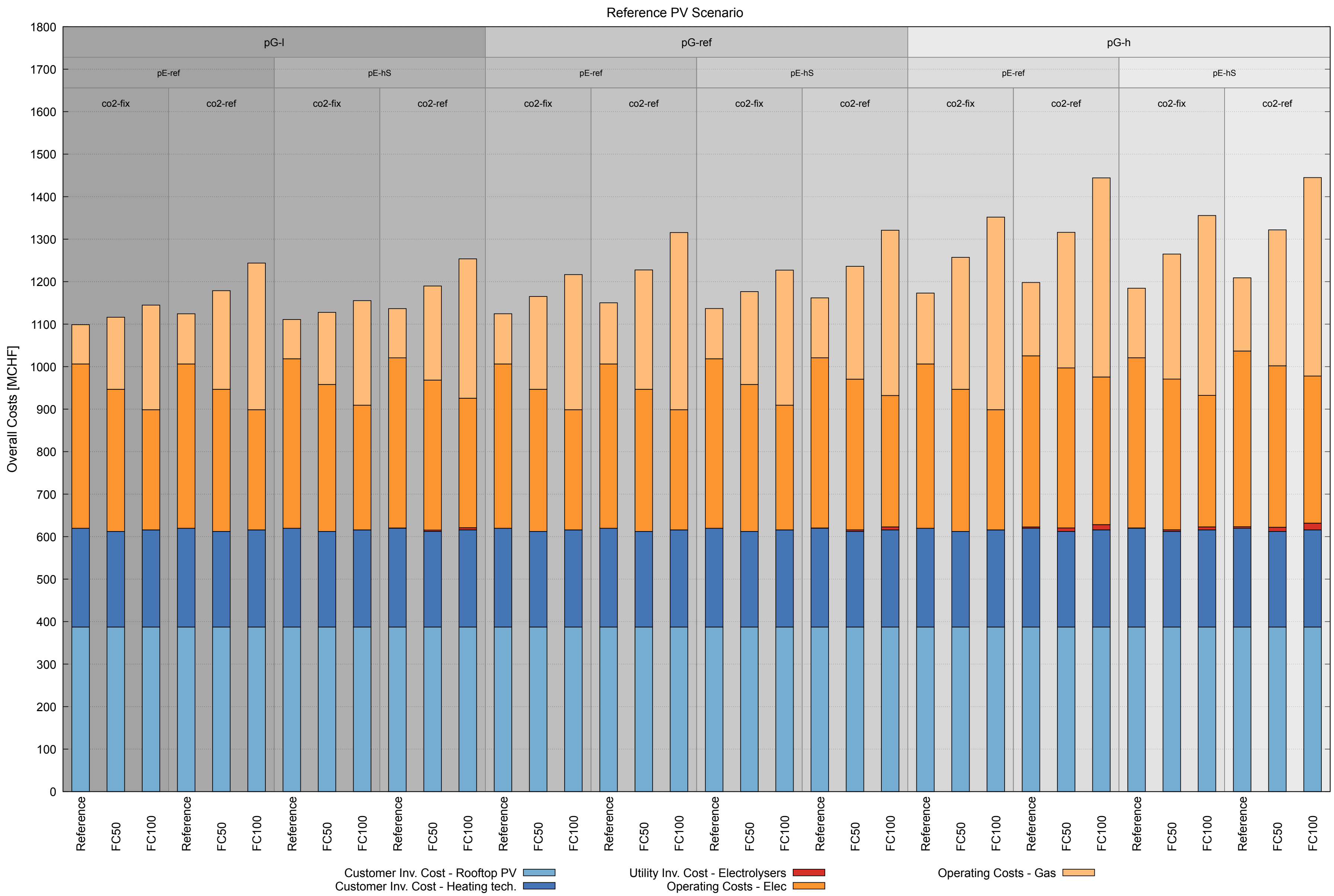

Figure 4.3.1: Total costs of the various demand scenarios for the "Reference" PV scenario.

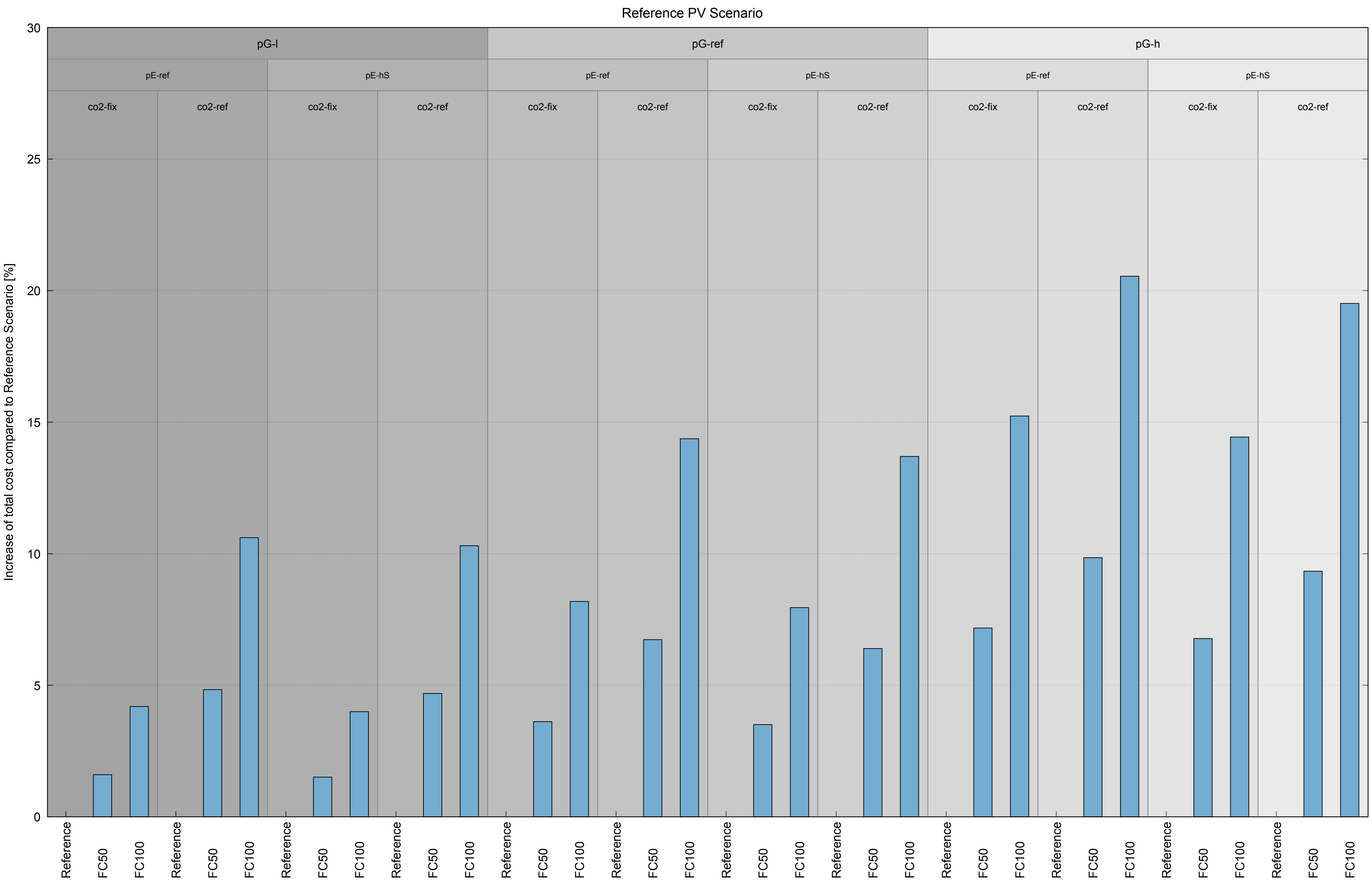

Figure 4.3.2: Total cost increase of the various scenarios compared to the Reference scenario for the "Reference" PV scenario

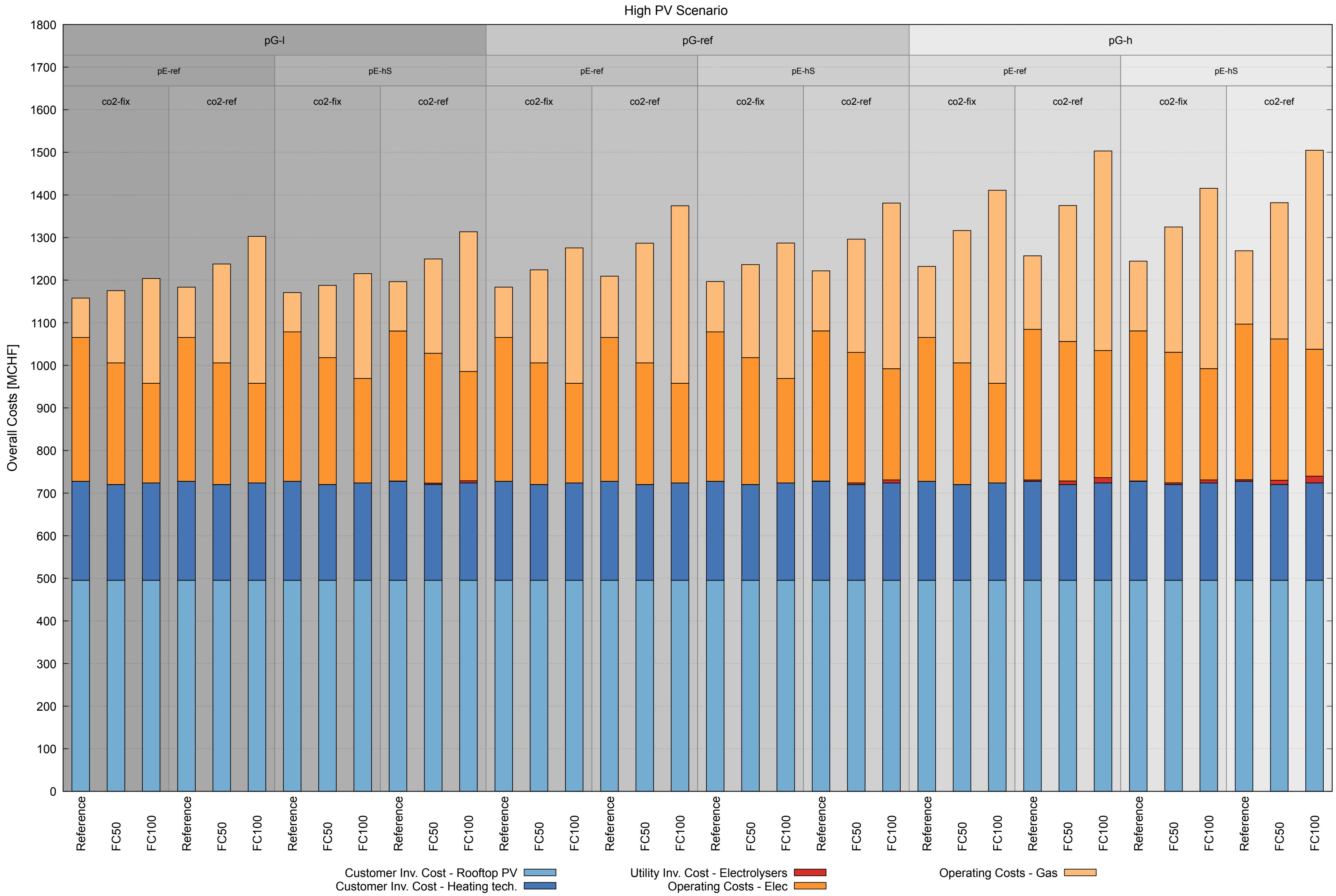

Figure 4.3.3: Total costs of the various demand scenarios for the "High" PV scenario.

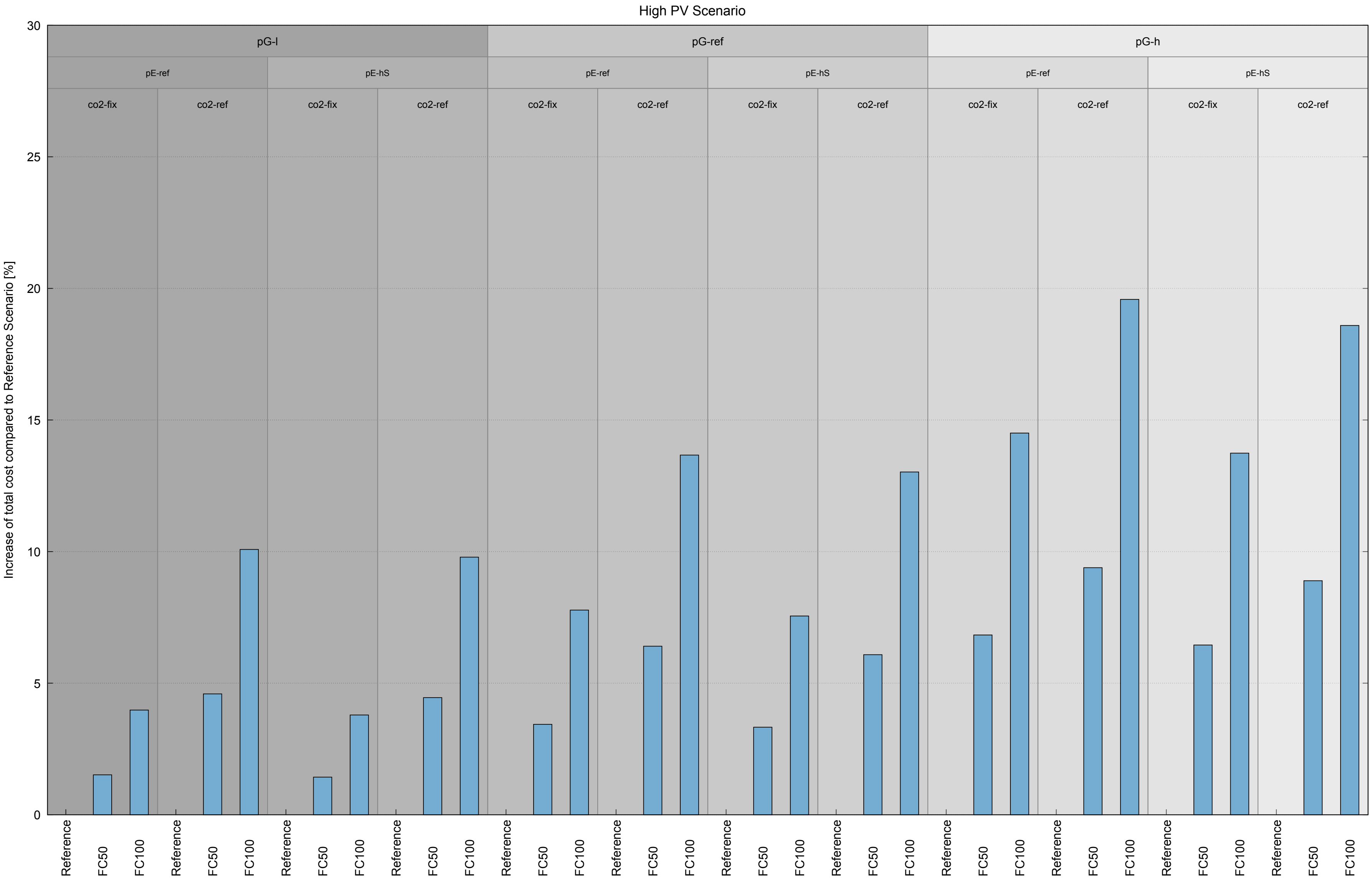

Figure 4.3.4: Total cost increase of the various scenarios compared to the Reference scenario for the "High" PV scenario

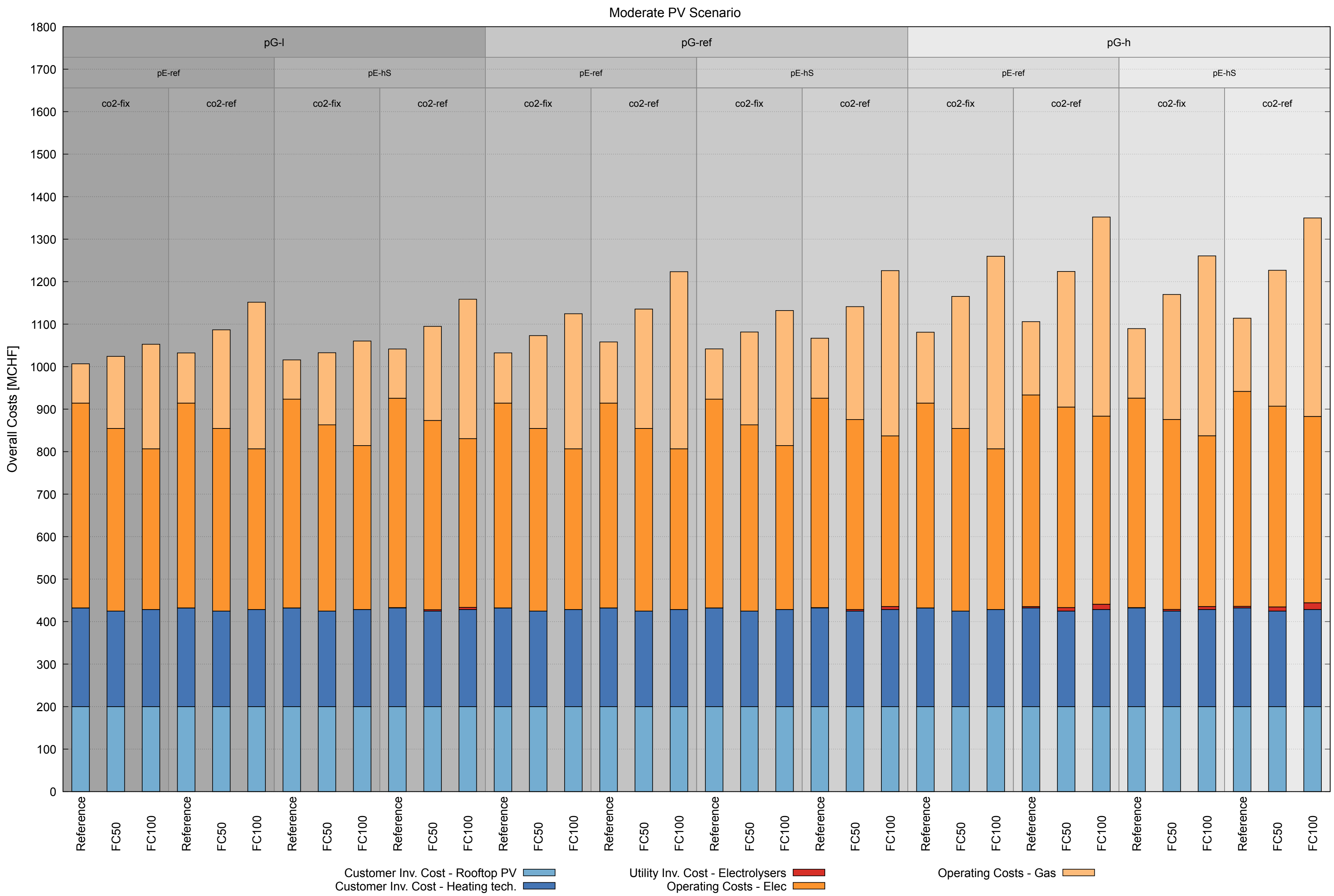

Figure 4.3.5: Total costs of the various demand scenarios for the "Moderate" PV scenario.

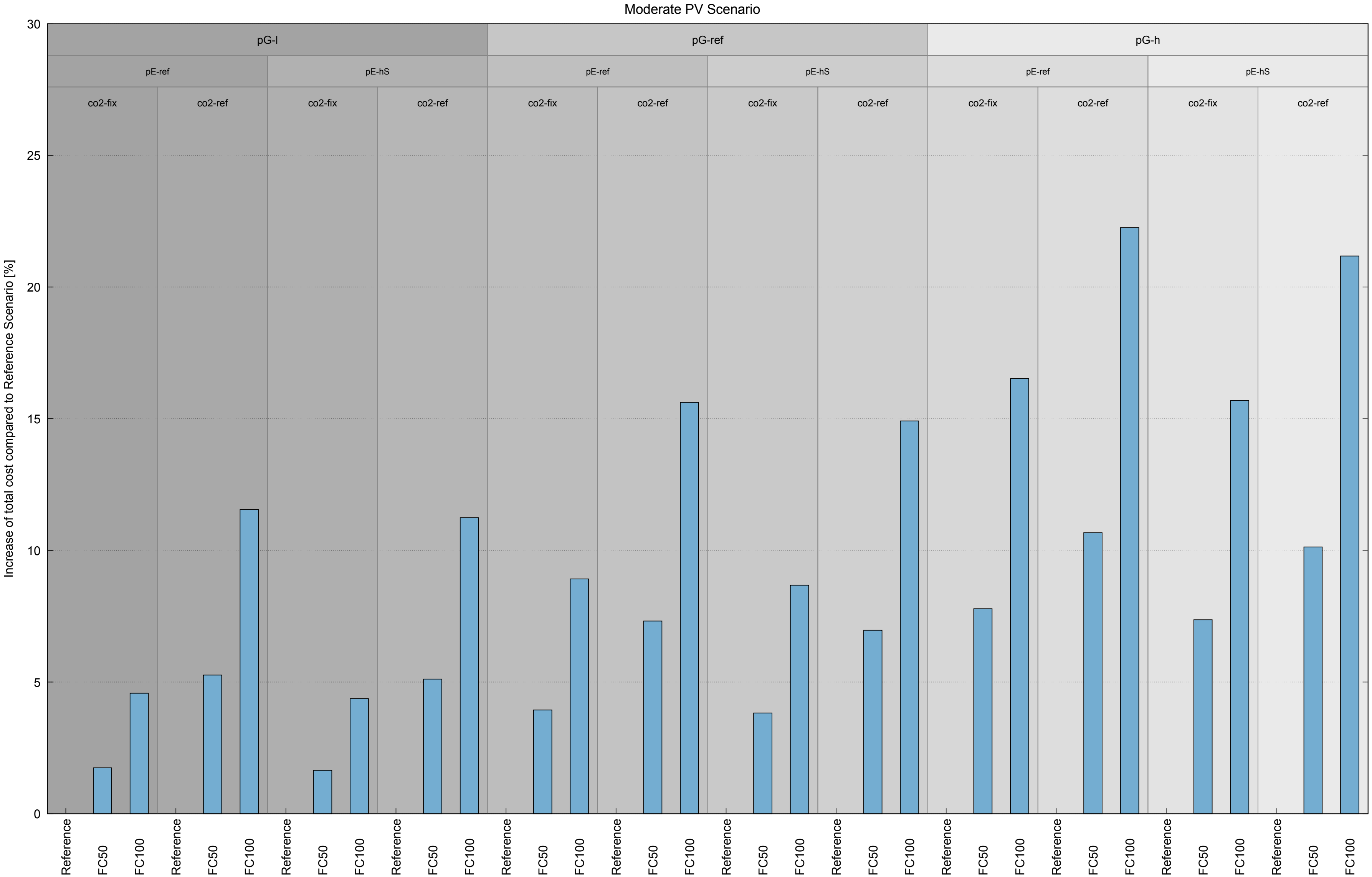

Figure 4.3.6: Total cost increase of the various scenarios compared to the Reference scenario for the "Moderate" PV scenario

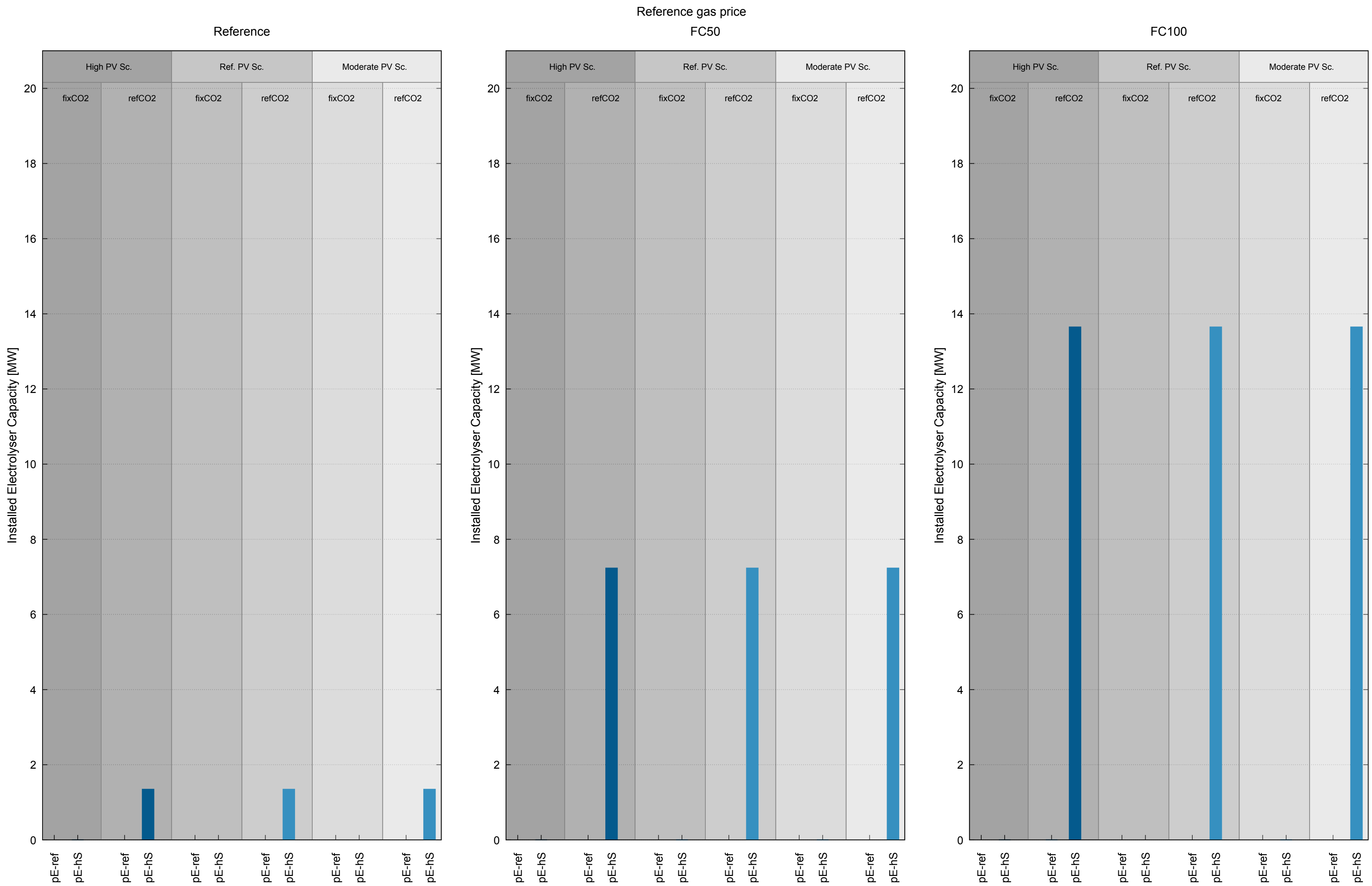

Figure 4.3.7: Outcome of the optimization for various scenarios, for the "Reference" gas price scenario: Total investment costs in electrolysers.

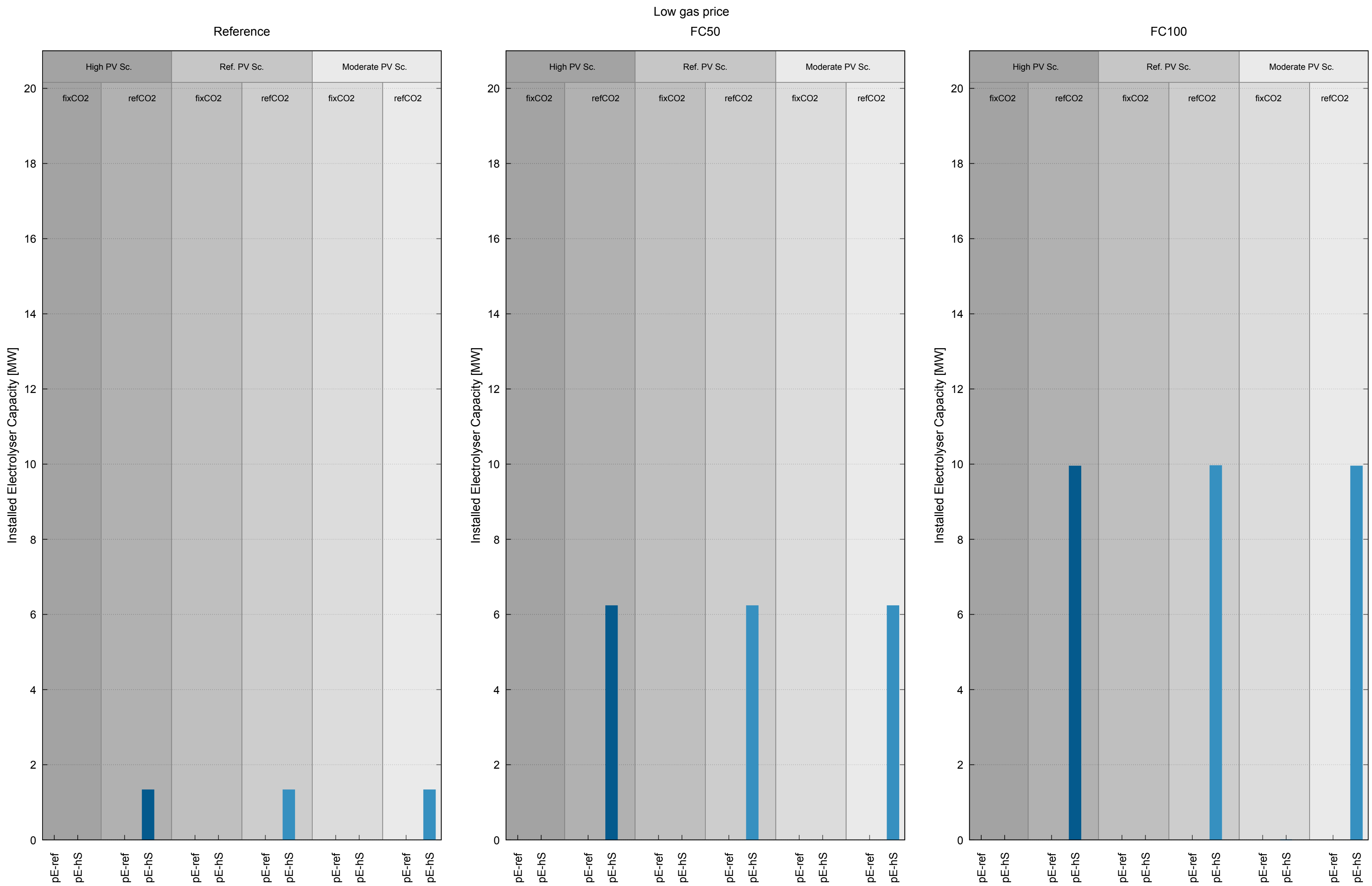

Figure 4.3.8: Outcome of the optimization for various scenarios, for the "Low" gas price scenario: Total investment costs in electrolysers.

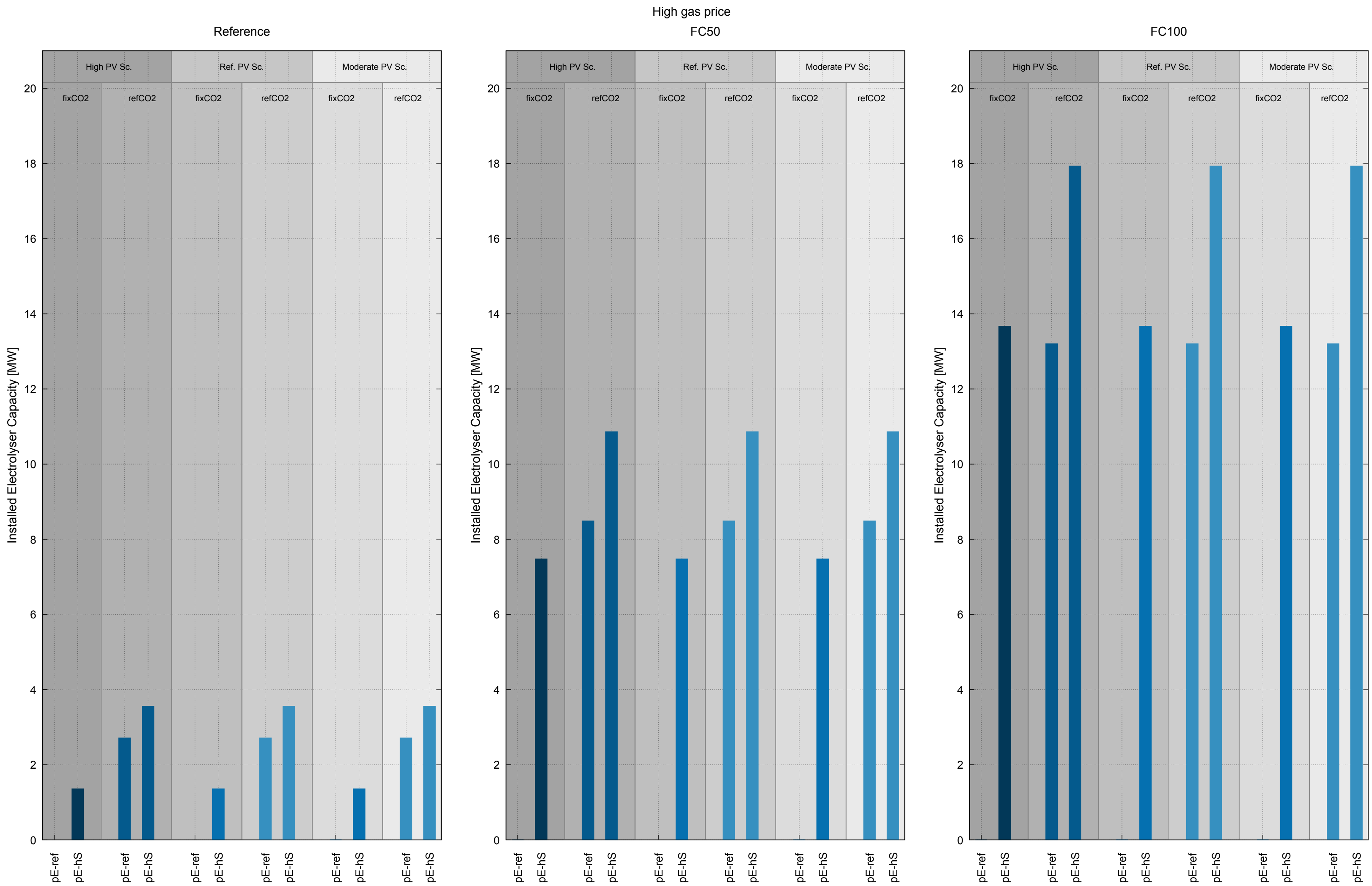

Figure 4.3.9: Outcome of the optimization for various scenarios, for the "High" gas price scenario: Total investment costs in electrolysers.

4.4 Total cost analysis of alternative pathways: District heating based on the water from the Lake of Zug (Circulago project)

In this section, we aim at quantifying the value of resorting to a district heating network as an alternative to local investments into heating technologies (i.e. heat pumps and gas boilers) made by the customers. Precisely, as explained in Section 3.1, we consider the so-called Circulago project [7], in which a heat-pump-based district heating network provides heating to the interested customers utilizing the water of the Lake of Zug as the source of heat energy. Clearly, this is an "electrification" scenario, since Circulago eventually consumes electricity for the operation of its heat pumps.

For each of the "Reference" and "Mild Gas" demand scenarios, we assume that certain customers opt to connect to Circulago, as explained in Section 3.1. The resulting electricity and gas demand for heating are presented in Figure 3.1.2 (left plot). These two exogenously defined demand scenarios are combined with the three PV scenarios the three gas price scenarios and a selection of the electricity price scenarios (pE-ref, pE-hS, pE-IM, pE-IMhS) to make up a set of input scenarios for each of which the optimization problem is solved. For comparison purposes, the various combinations were also made for the "Reference" and "Mild Gas" demand scenarios (i.e. without Circulago). In all cases, the "AEC-Ref", "Bat-Med" and "PAFC-Ref" scenarios are used.

One can observe, in Figures 4.4.1, 4.4.3, and 4.4.5, that in all cases the investment in the district heating network results in lower operating cost. Recalling from Figure 3.1.2 that in the Circulago scenarios a considerable amount of customer-level heat pumps are replaced by the utility-level heat pumps utilized to eventually draw heat from the lake, one can associate the reduction in the total operating cost to a reduction of the total cost of purchasing electricity, due to the higher efficiency of the utility-level heat pumps (as opposed to customer-level ones, which are mostly air-sourced).

The total required investment cost of implementing Circulago is practically the same compared to the "Reference" scenario, while it is extremely slightly (practically negligibly) higher than the "Mild Gas" scenario. As a result, *Circulago reduces the total cost for serving the end demand for space heating*. This total cost reduction happens in all considered scenarios, however it is more pronounced when the gas and/or the electricity price is higher. It is not affected by the amount of PV penetration.

Similarly to the observation made in Section 4.2, the total cost gains are small (2-5%, depending on the scenario assumptions, see Figures 4.4.2, 4.4.4 and 4.4.6,). However, the materialization of this project is in the hands of the utility, which is an institution better suited for long-term planning decisions compared to an average customer. It is reasonable to assume that such a project might make up an interesting offer for the average customer, since part of the "package" is the fact that the latter will not need to care about his/her heating system anymore.

Finally, Figures 4.4.7, 4.4.8 and 4.4.9 show the optimal amount of utility-scale electrolyser capacity that makes economic sense to invest in, for different demand, PV and electricity and gas price scenarios. Let us observe that relying on a heat-pump-based district heating network decreases the demand for gas (since customer change their heating system) and, as a result, the value of investing in electrolysers. The relation between gas demand and value of electrolysers is presented in detail in Section 4.7.

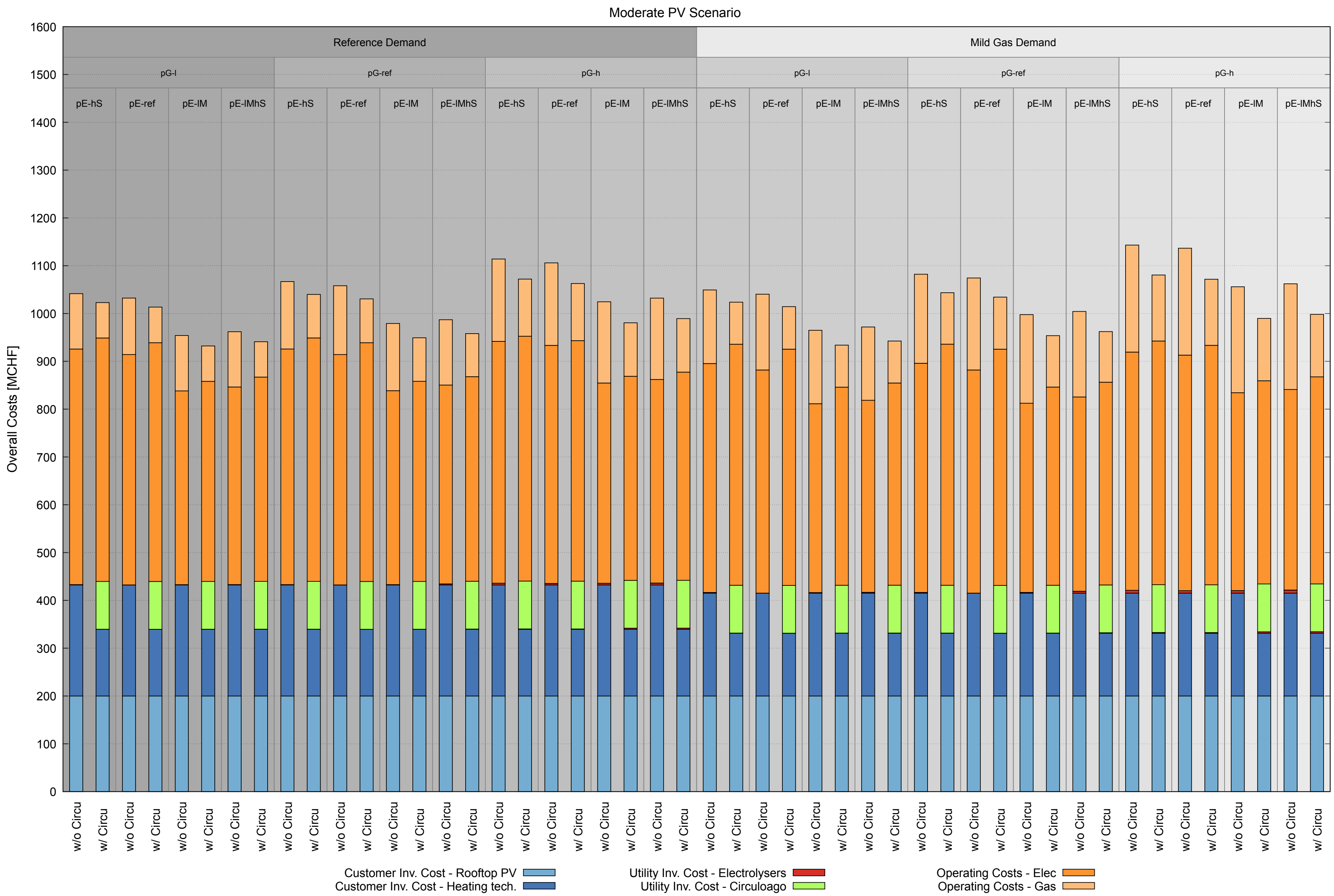

Figure 4.4.1: Outcome of the optimization for various scenarios, with and w/o the Circulago project being materialized: Total costs.

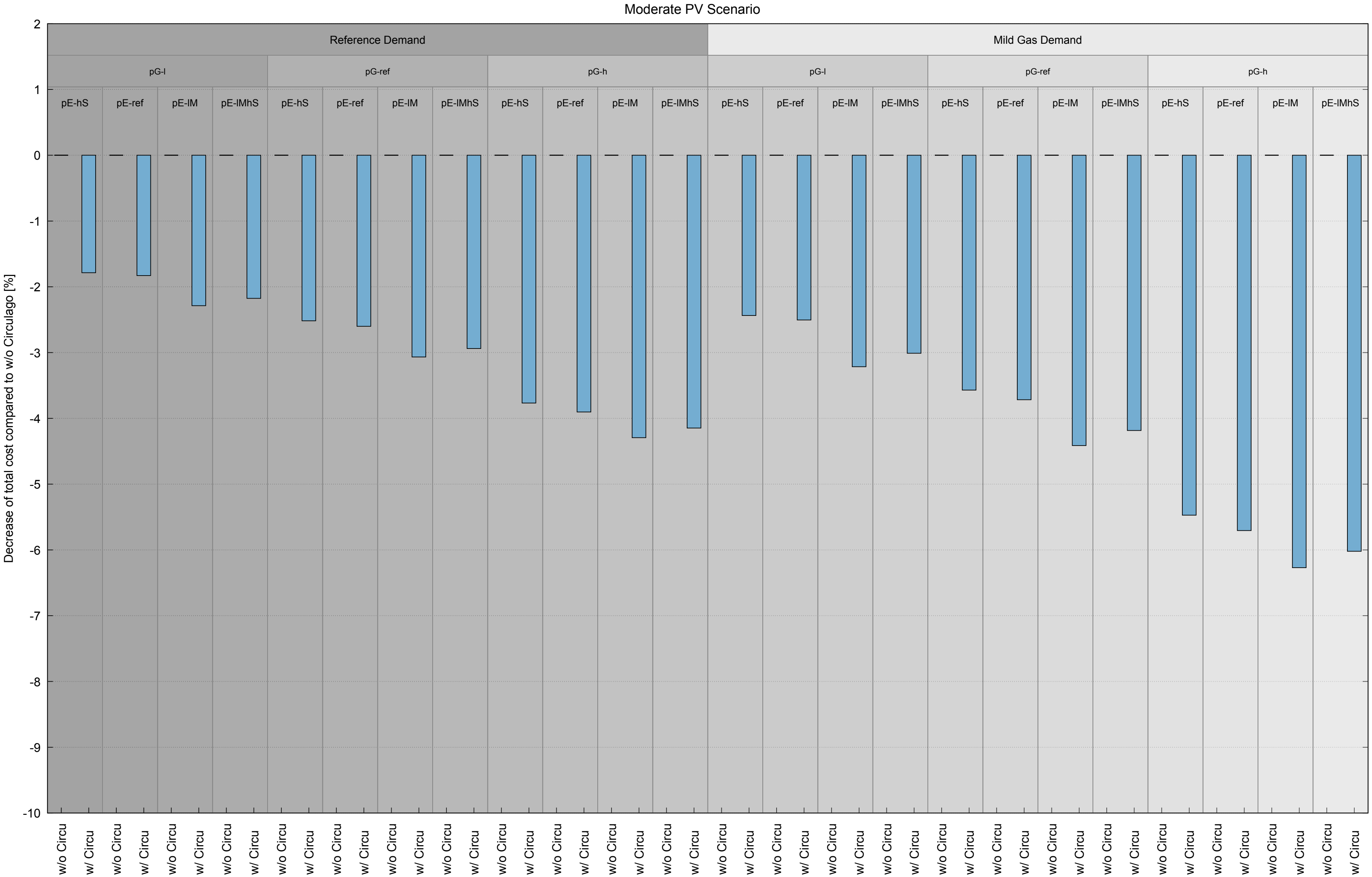

Figure 4.4.2: Total cost decrease of the various scenarios compared to w/o Circulago for Moderate PV Scenario

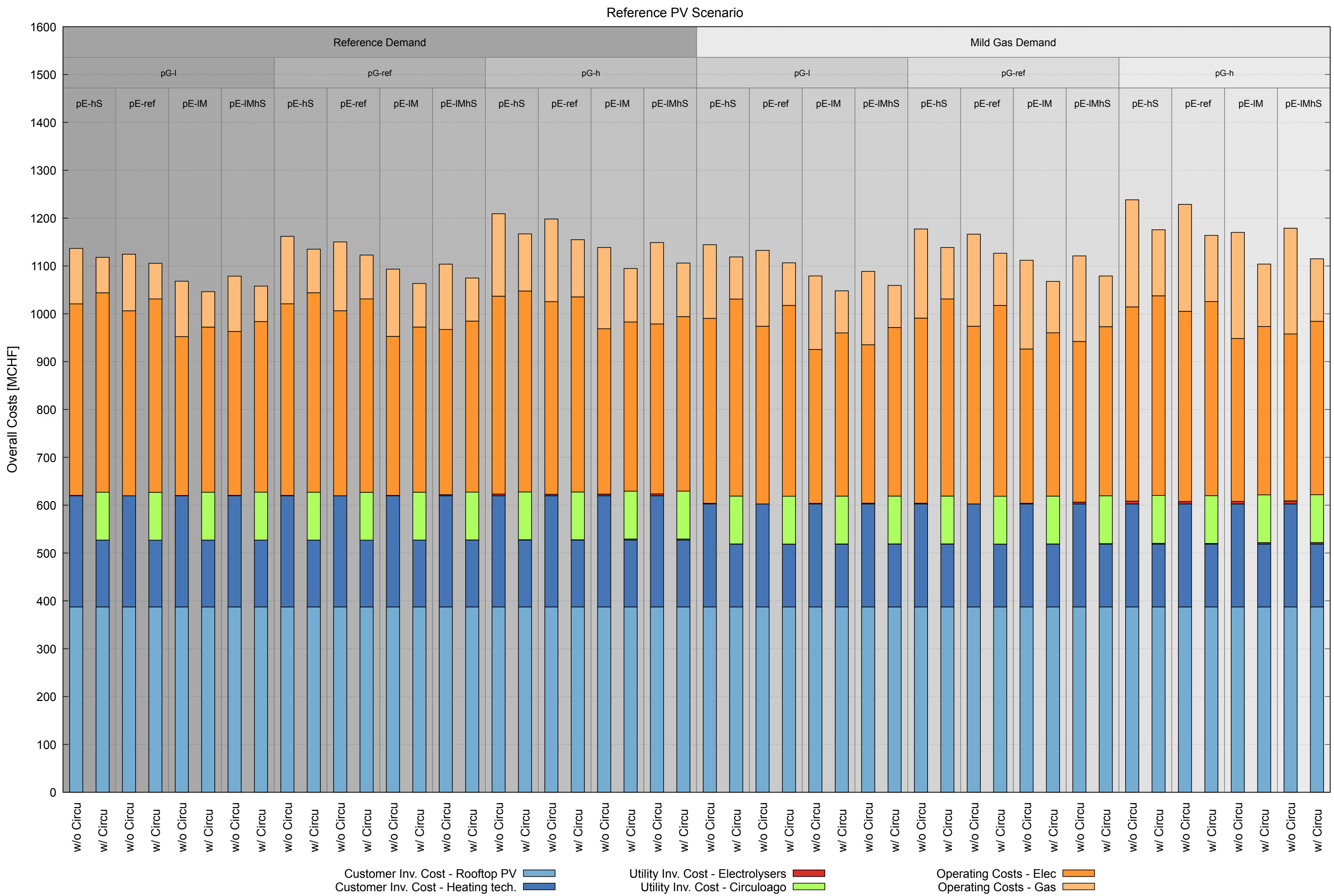

Figure 4.4.3: Outcome of the optimization for various scenarios, with and w/o the Circulago project being materialized: Total costs.

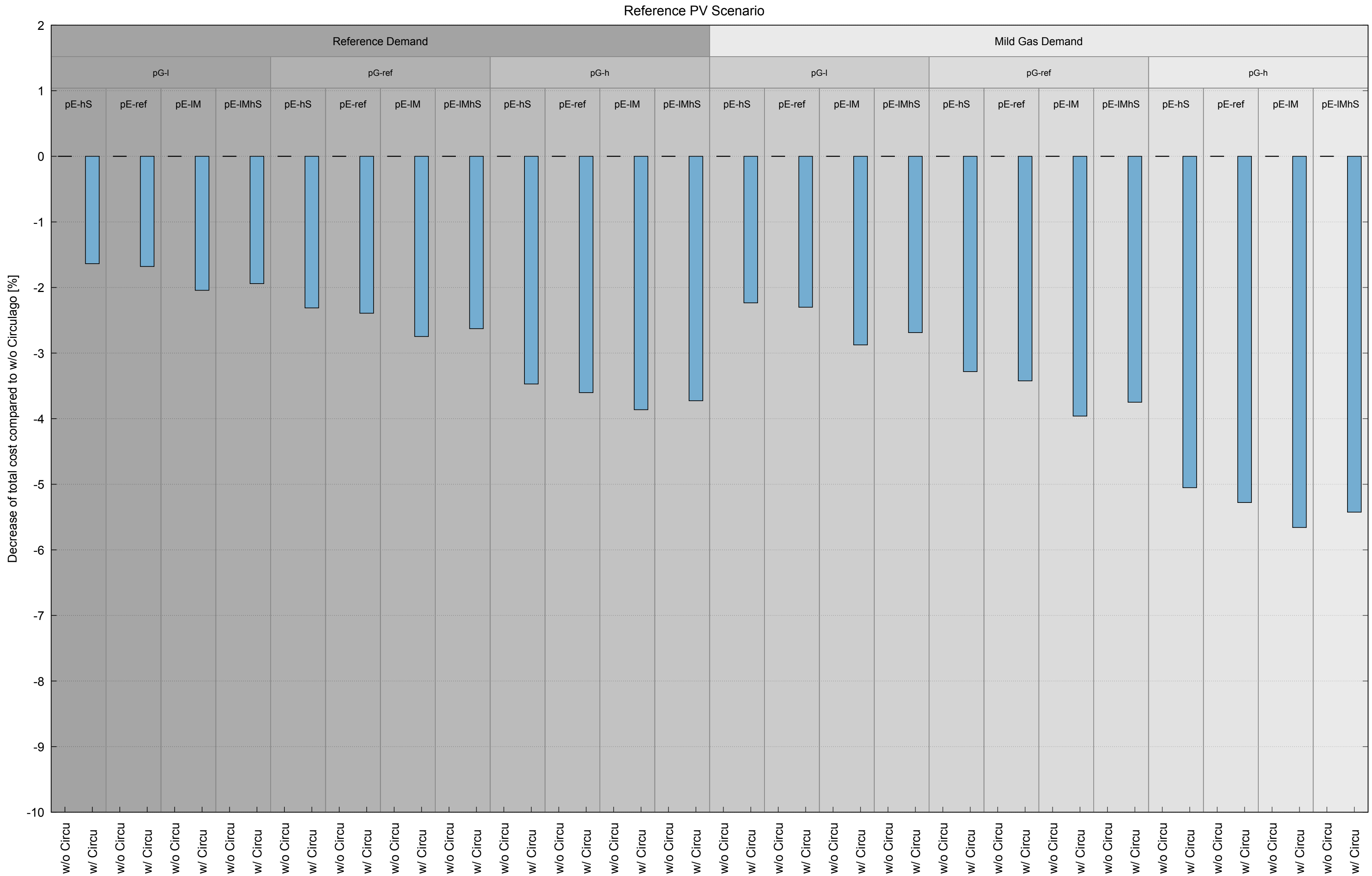

Figure 4.4.4: Total cost decrease of the various scenarios compared to w/o Circulago for Reference PV Scenario

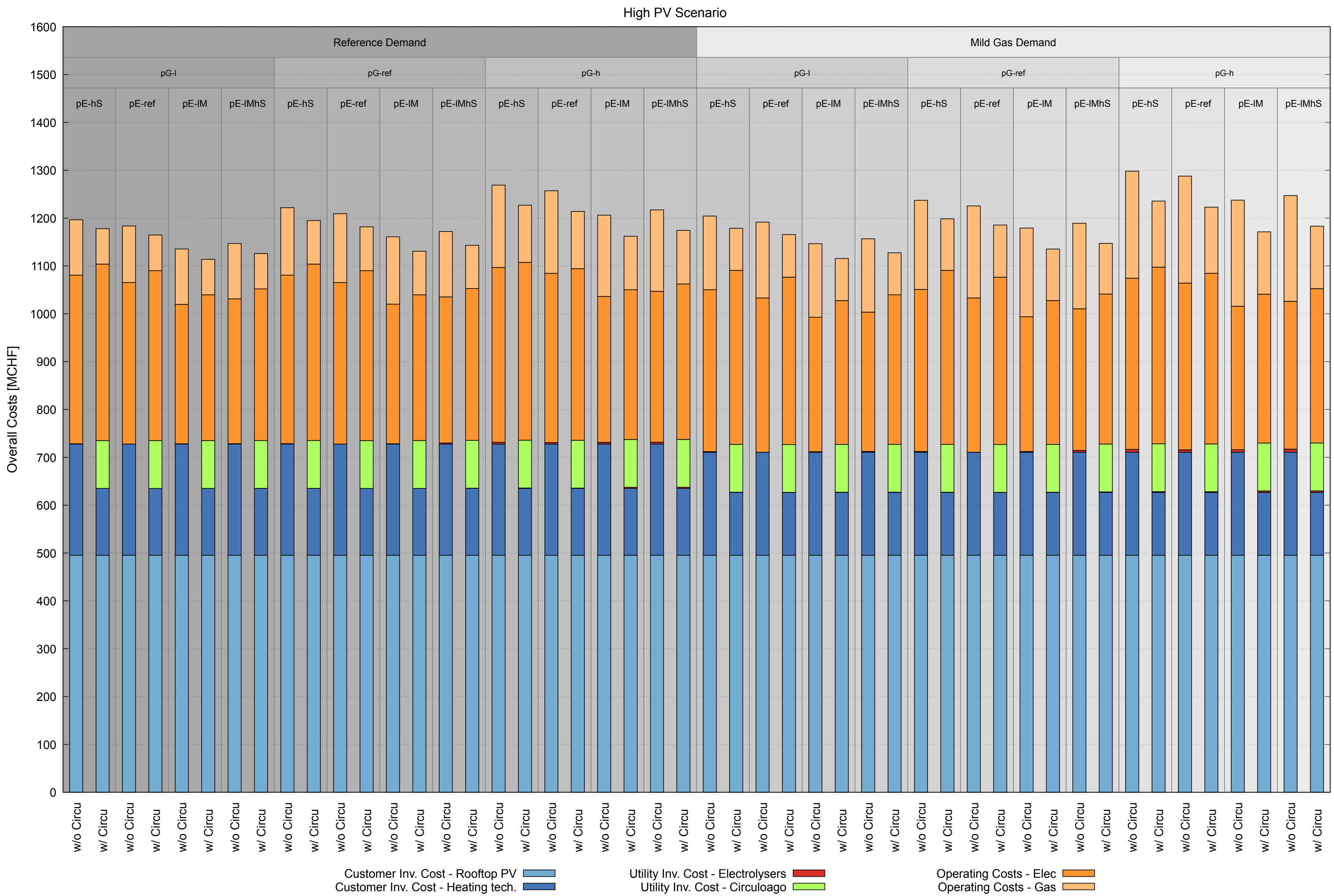

Figure 4.4.5: Outcome of the optimization for various scenarios, with and w/o the Circulago project being materialized: Total costs.

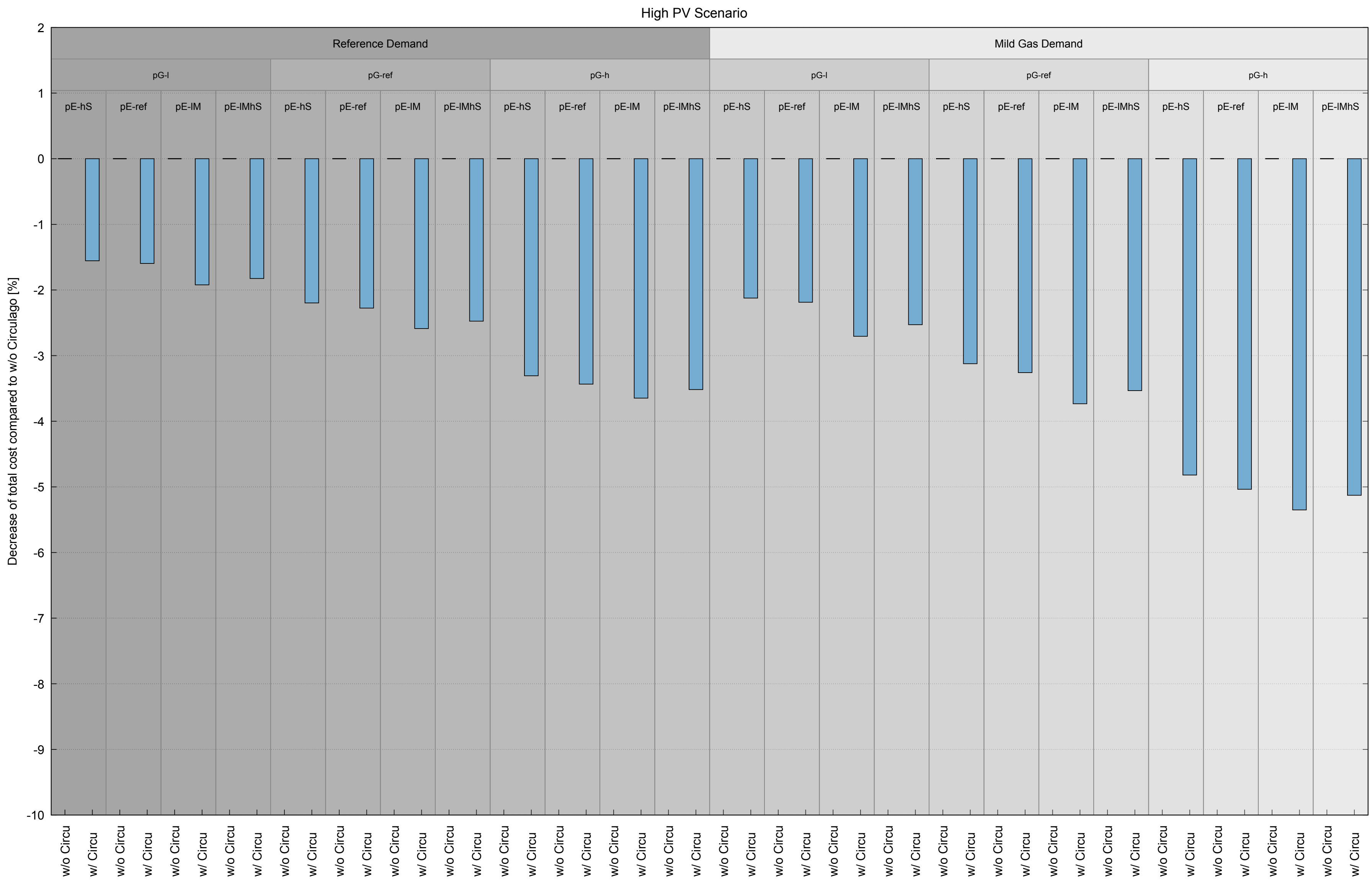

Figure 4.4.6: Total cost decrease of the various scenarios compared to w/o Circulago for the "High" PV Scenario

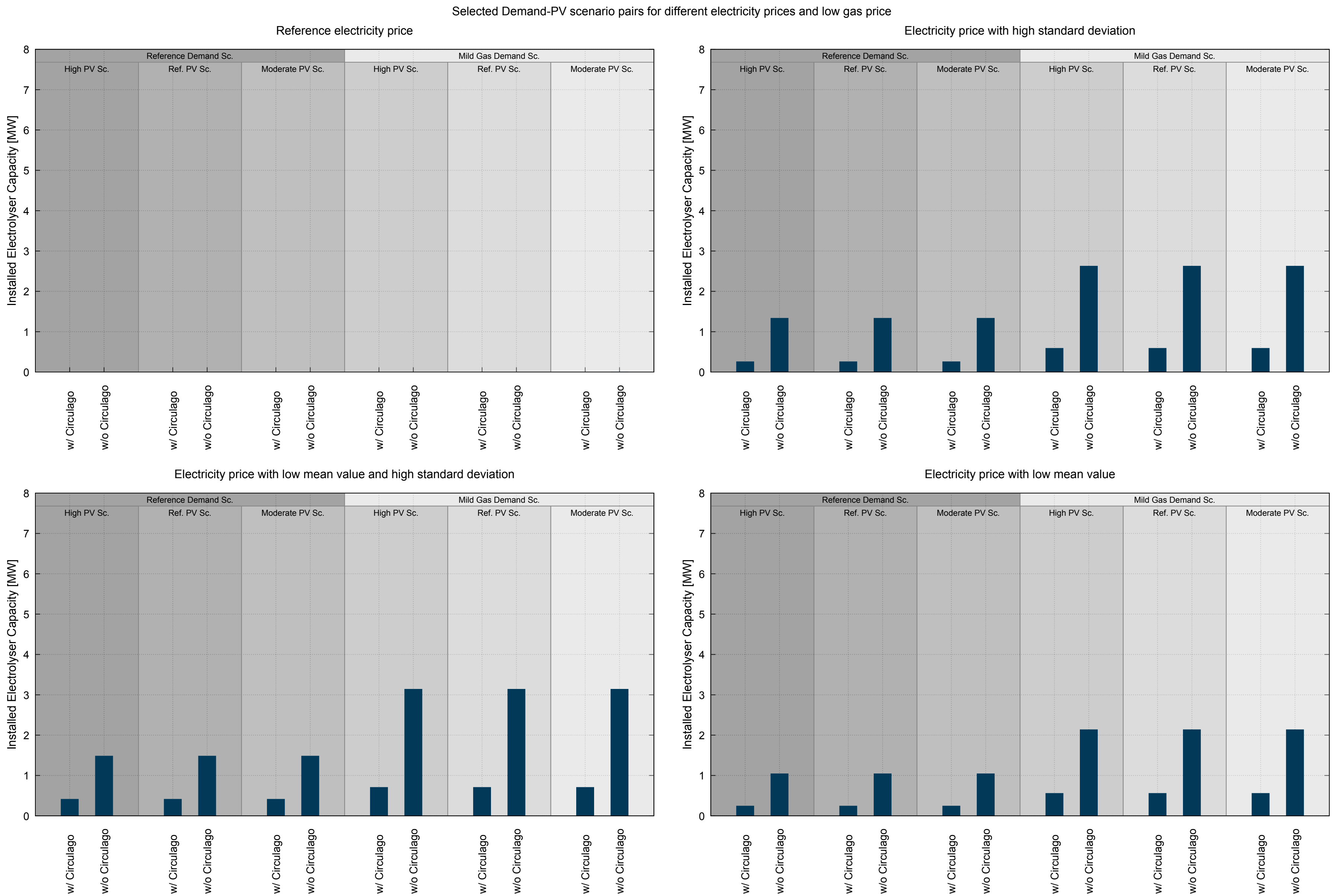

Figure 4.4.7: Outcome of the optimization for various scenarios, with and w/o the Circulago project being materialized: Optimal investments in electrolyser capacity. Absence of a bar denotes that the value is zero.

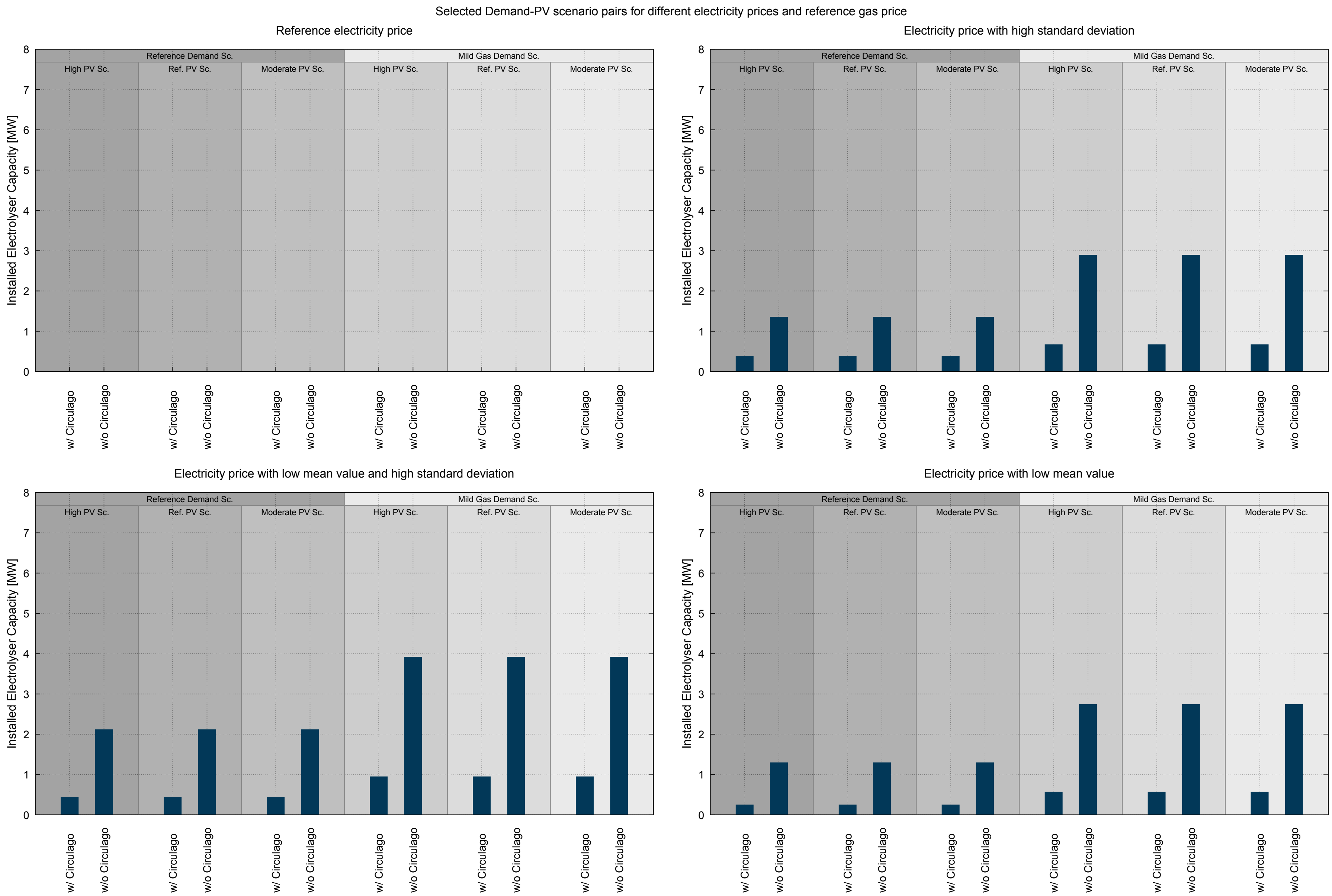

Figure 4.4.8: Outcome of the optimization for various scenarios, with and w/o the Circulago project being materialized: Optimal investments in electrolyser capacity. Absence of a bar denotes that the value is zero.

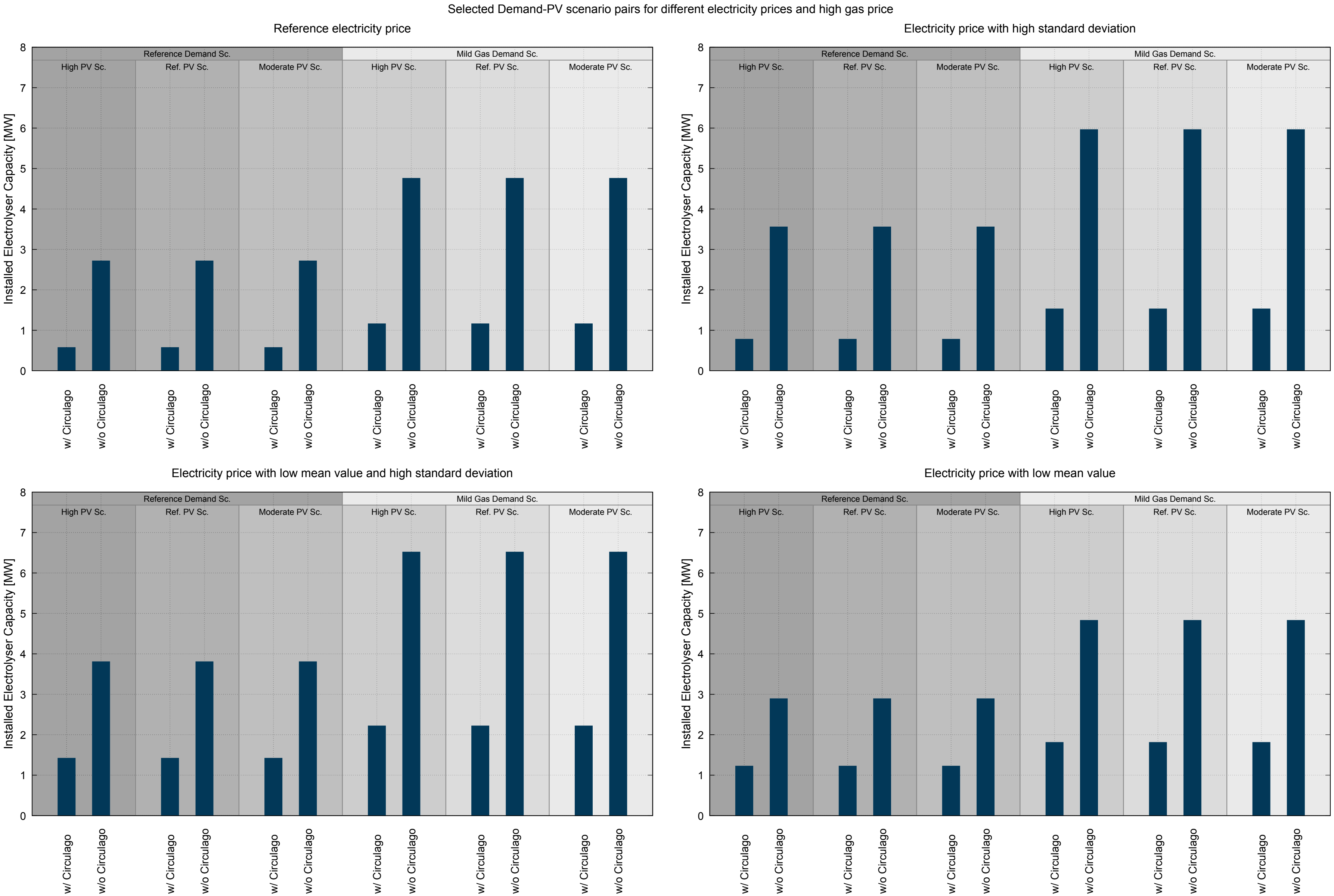

Figure 4.4.9: Outcome of the optimization for various scenarios, with and w/o the Circulago project being materialized: Optimal investments in electrolyser capacity.

4.5 Total cost analysis: Overall results

In this section, we present together the results from Sections 4.2, 4.3 and 4.4 to facilitate the reader in comparing them with each other. Figure 4.6.1 shows the total cost of all the eight demand scenarios considered in this study, for the "Reference" PV and "Reference" CO2 tax scenarios. All three gas price scenarios are shown in this figure, and two electricity price scenarios ("Reference" and "High Std").

Figure 4.6.2 shows the total cost of each demand scenario expressed as a percentage difference compared to the "No Gas" scenario, which is used as reference here. One can observe that the two cases where Circulago is implemented result in lower total cost, not only than their corresponding "without Circulago" scenario (i.e. the "Reference" and the "Mild Gas" scenarios) , but also than the "No Gas" scenario. This validates the finding that investing into the Circulago project, instead of individual customers progressively switching to local heat pumps, makes economic sense in the long-term, while offering the same CO2-reduction benefits. One can also observe that the fuel-cell-based scenarios ("FC50" and "FC100") are significantly more expensive than the others, even in the "Low" gas price scenarios.

Finally, Figure 4.6.3 allows the reader to see in detail the impact of each scenario solely on the operating cost, i.e. the cost of purchasing the required electricity and gas at the wholesale.

4.6 Utilization of the results of this analysis in the context of a CO2 net-zero energy system

As explained in Section 2.3, even if this study is not designed for this purpose, the obtained results can be used to assess the relative value of other types of methane gas (i.e. not natural gas), such as biogas or synthetic "renewable" methane produced by electricity via an electrolysis and a methanation step. If an assumption is made regarding the price at which the utility can purchase the methane gas of interest, then Table 3.3.6 can be used in order to identify a scenario where the final cost of gas (resulting from the natural gas price and the CO2 tax) is the closest to the assumed price of the methane gas under investigation. The results of this study corresponding to the selected combination of natural gas price and CO2 tax are those better reflecting the value of another methane gas of the same final cost.

For example, assuming that another study, like [13] or [14], projects that the cost of synthetic methane will be 75-100 €/MWh in 2050, then the value of such a methane in the context of the distribution system considered in this study can be estimated as approximately the value of the scenario combinations "Low Gas - Reference CO2" and "High Gas - Fixed CO2".

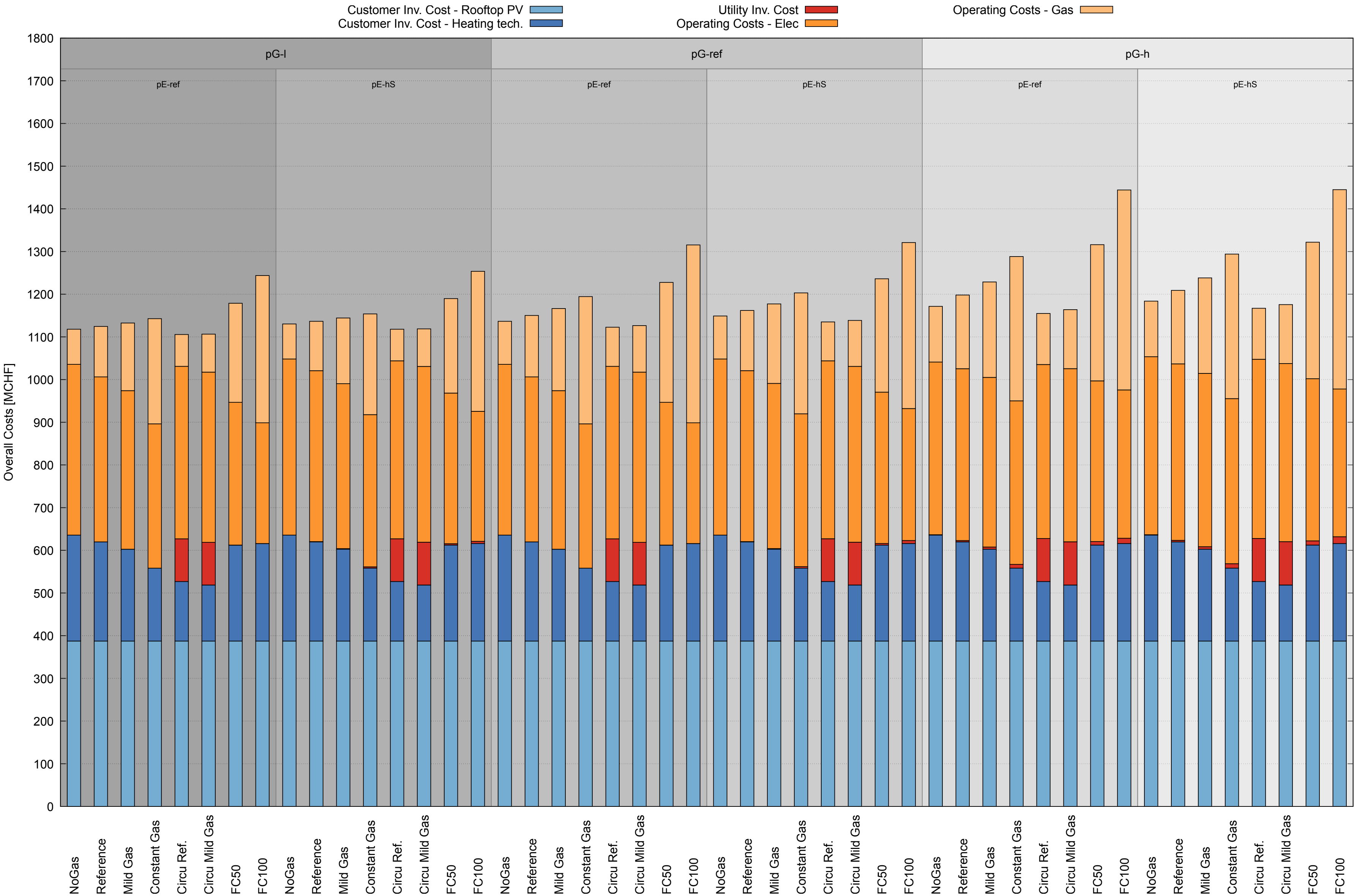

Figure 4.6.1: Total costs of the various scenarios for the Reference PV scenario and Reference CO2 tax.

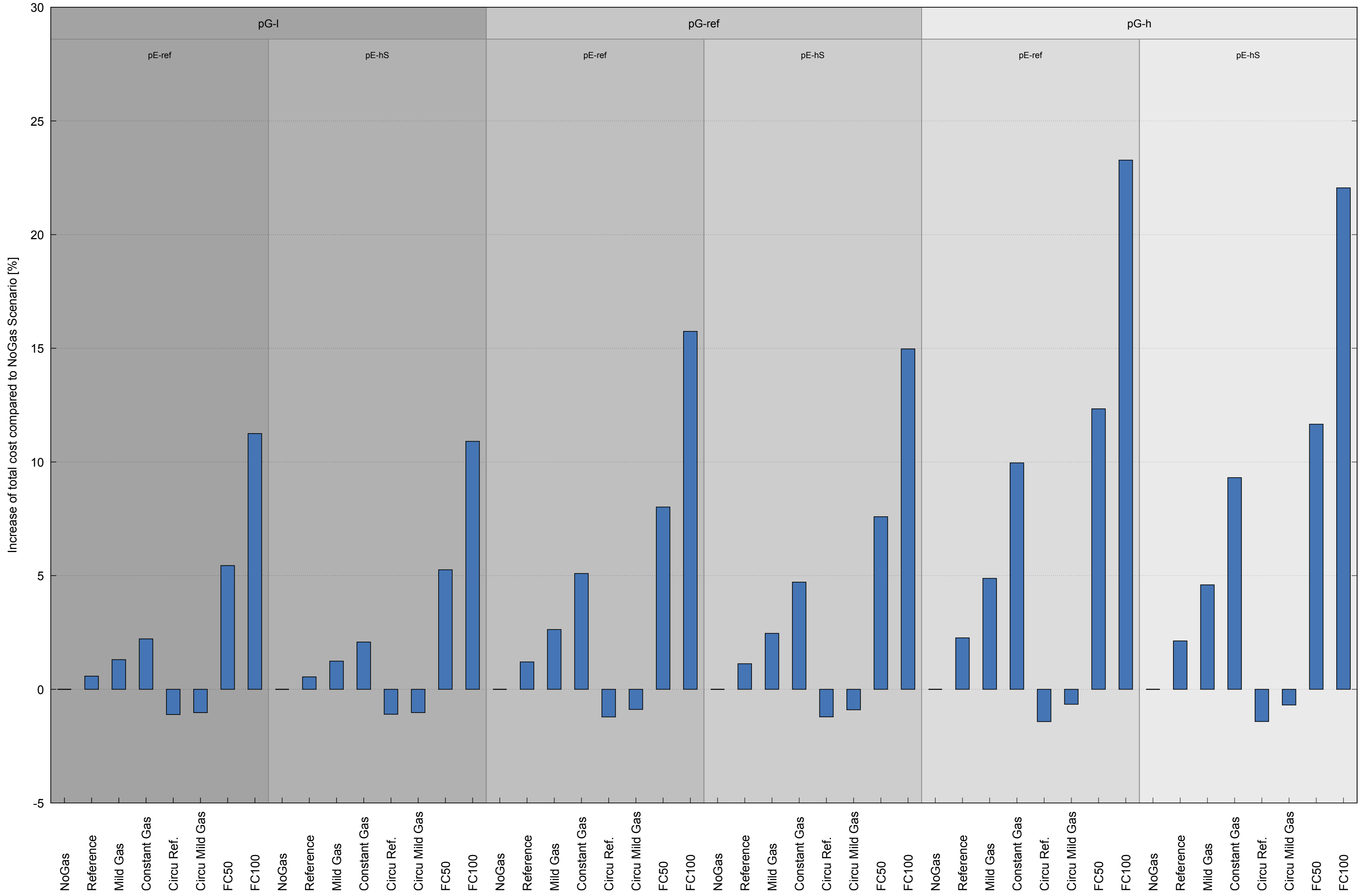

Figure 4.6.2: Total cost increase of the various scenarios compared to the No-Gas demand scenario for the Reference PV scenario and Reference CO2 tax.

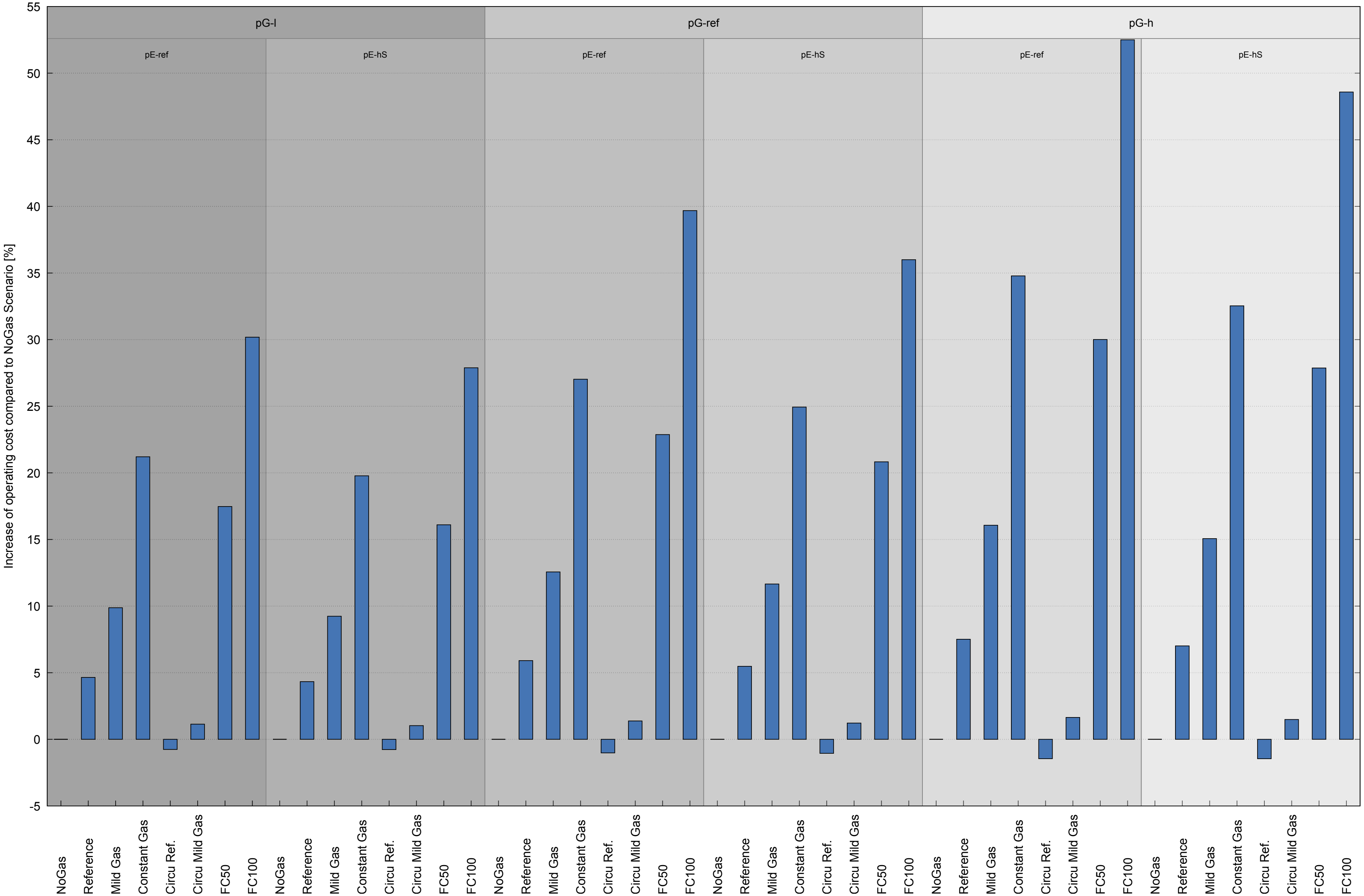

Figure 4.6.3: Operating cost increase of the various scenarios compared to the No-Gas demand scenario for the Reference PV scenario and Reference CO2 tax.

4.7 Sensitivity analysis on value of utility-scale technologies: Electrolyzers

This section presents the sensitivity analysis performed to identify under which conditions it makes sense for a utility to invest in electrolyzers. Since electricity network congestion is not a driver for utility-scale investments (as shown in Section 4.1), we perform the optimization for various demand, PV penetration, price and technology scenarios *without* considering network constraints. We still however limit the import/export of electric power according to the limits of the HV/MV transformers.

The sensitivity analysis is performed over the following parameters:

1. the electrolyzer CAPEX, per Table 3.4.1,
2. the natural gas price, per Table 3.3.4
3. the CO2 tax (and hence the natural gas final cost), per Table 3.3.6, and
4. the wholesale electricity price, for different combinations of mean value and standard deviation, per Tables 3.3.1 and 3.3.2.

Figures 4.7.1, 4.7.2, 4.7.3 and 4.7.4 show the results. Each figure corresponds to a specific combination of demand, PV penetration and natural gas price scenarios, as stated at the top of the figure. The "Low-Bat" (Table 3.4.2) and "PAFC-Ref" (Table 3.4.3) scenarios have been used for the battery and, respectively, the fuel cell CAPEX.

The following observations can be made:

1. For the reference electrolyzer CAPEX, electricity price, natural gas price and CO2 tax assumed in this study, it is not economic for the utility to invest in electrolyzer capacity.
2. However, many scenario parameters have been identified, for which electrolyzers have a value for the utility. Precisely, as expected, lower electrolyzer CAPEX, lower electricity price and higher natural gas cost (resulting from higher natural gas price and/or higher CO2 tax) are all factors which motivate installation of larger total electrolyzer capacity.
3. The reason why electrolyzer capacity is built, is in order to satisfy the gas demand by consuming electricity (instead of purchasing natural gas from the gas wholesale system) when electricity is cheap enough.
4. Higher demand for gas results in higher need to electrolyser capacity (compare figures 4.7.1 and 4.7.2 with 4.7.3 and 4.7.4).
5. It is interesting to observe that increased electricity price variability motivates larger amounts of electrolyser capacity. The reason is that, for a given mean value, higher variability means that there are more frequent and more intense low-electricity-price hours. It is exactly during these hours that the electrolyser has the higher value, since then it can produce gas H2 which is considerable cheaper than natural gas.
6. Note that even without a CO2 tax, electrolyser has value in specific scenarios.

It is interesting to bring up that, in the case which is the most favorable for an electrolyzer installation, i.e. the "Mild Gas demand"-"Moderate PV" pair, with "AEC-Low" electrolyser CAPEX, "High" natural gas price, "Reference" CO2 tax and "Low Mean - High Std" electricity price, a total of 8 GWh of gas H2 is produced in 2050 (consuming 10 GWh of electricity), while a total of 16 GWh of gas H2 is produced in 2030, covering the 20% of the total demand for gas of each year.

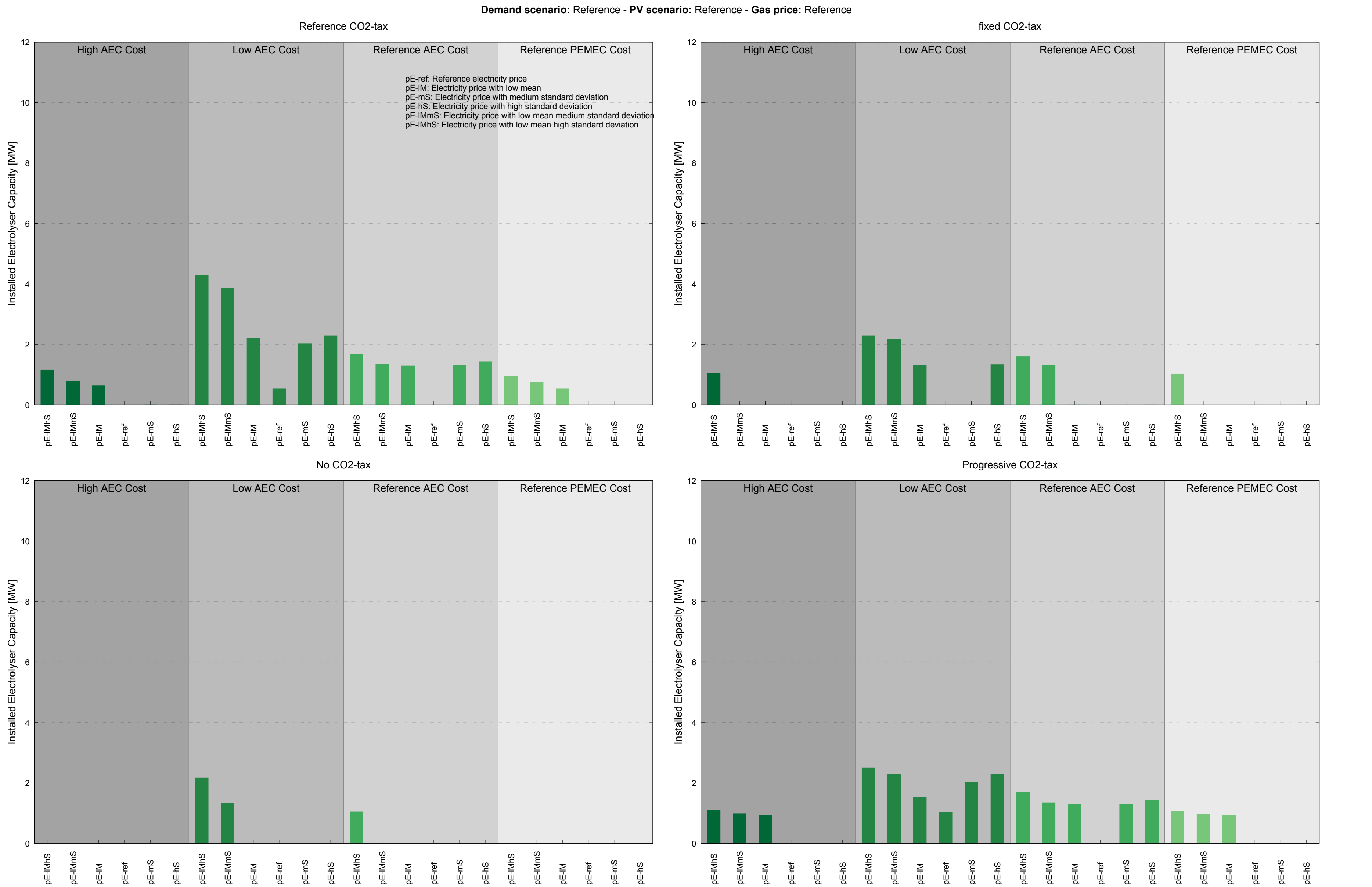

Figure 4.7.1: Sensitivity analysis performed for the "Reference" demand - "Reference" PV - "Reference" gas price and "Bat-Low" scenarios, presented in Section 3. Absence of a bar denotes that the value is zero.

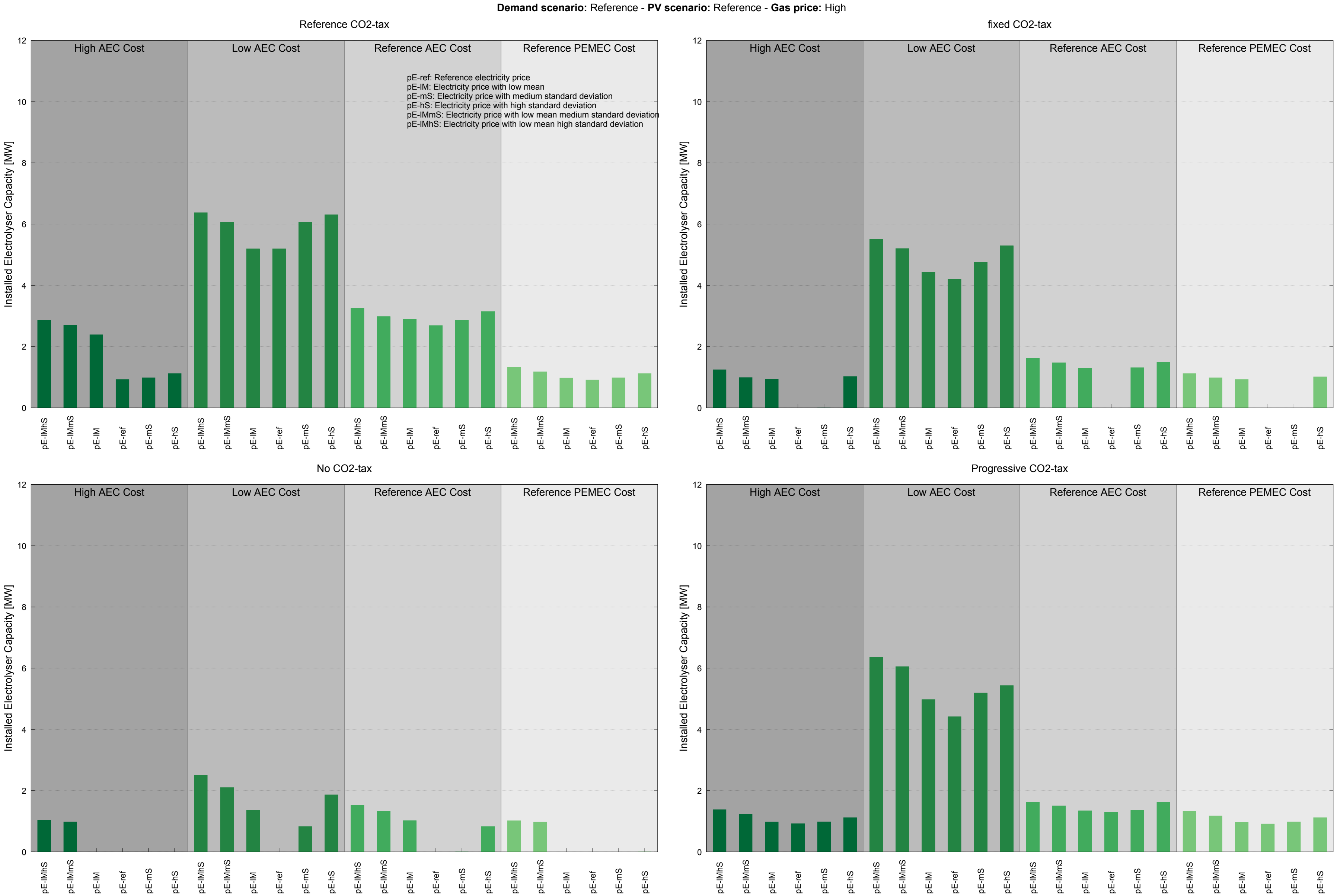

Figure 4.7.2: Sensitivity analysis performed for the "Reference" demand - "Reference" PV - "High" gas price and "Bat-Low" scenarios, presented in Section 3.

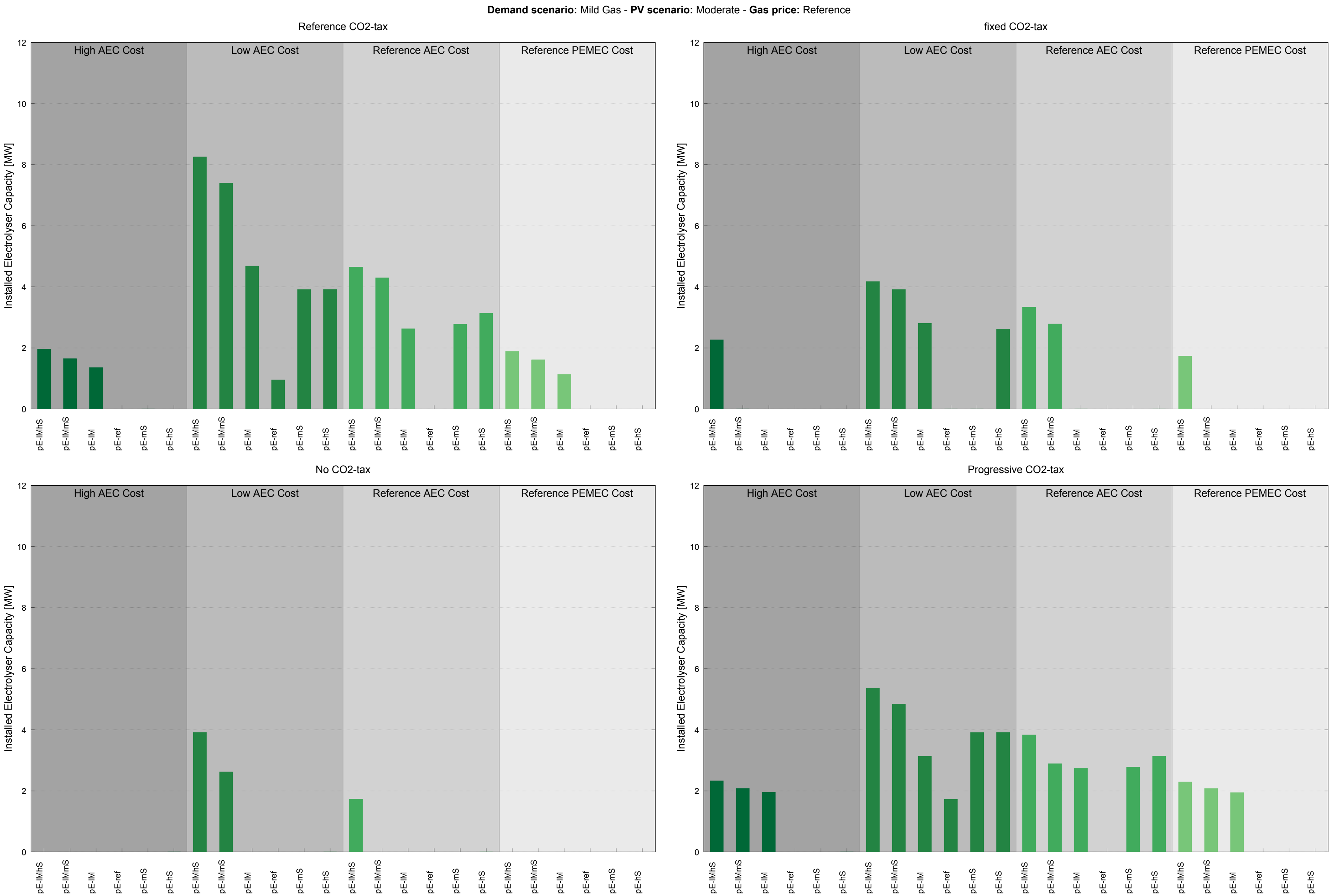

Figure 4.7.3: Sensitivity analysis performed for the "Mild Gas" demand - "Moderate" PV - "Reference" gas price and "Bat-Low" scenarios, presented in Section 3. Absence of a bar denotes that the value is zero. Absence of a bar denotes that the value is zero.

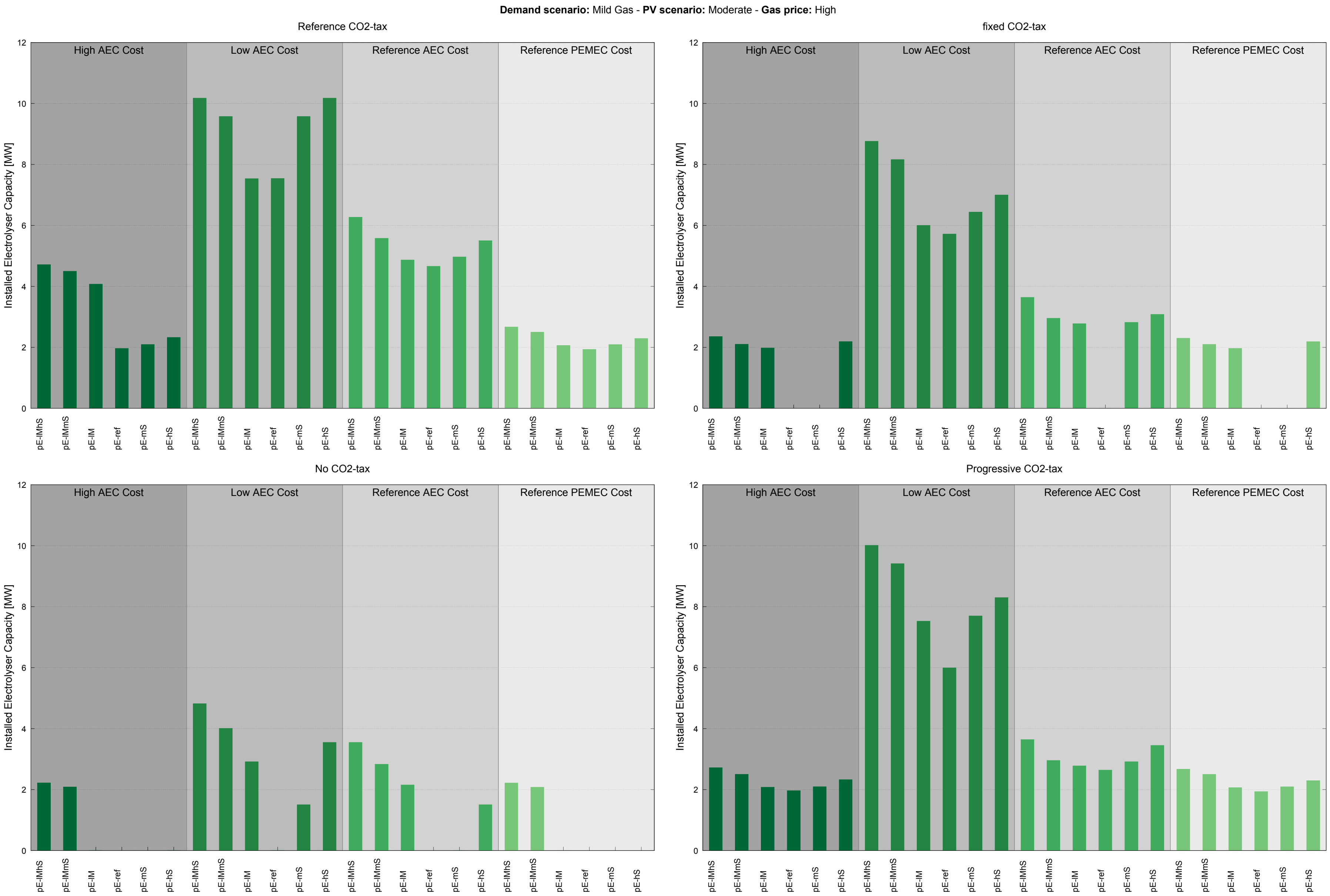

Figure 4.7.4: Sensitivity analysis performed for the "Mild Gas" demand - "Moderate" PV - "High" gas price and "Bat-Low" scenarios, presented in Section 3. Absence of a bar denotes that the value is zero.

Finally, it is of interest to observe in more detail the way that the electrolyser capacity is utilized. Figure 4.7.5 shows the hourly utilization for the year 2050 of the total installed electrolyser capacity, for the scenario (demand: "Mild Gas", PV: "Moderate", electricity price: "Reference", natural gas price: "High", CO2 tax: "Reference", electrolyzer CAPEX: "AEC-Ref")[17]. It can be observed that it cycles in an approximately daily basis. An almost binary operation is also observed (usually it either operates in full capacity or not at all). The reason for this behavior is that hydrogen production (or not) is almost exclusively depending on the value of the electricity price. If the latter is low enough to allow the electrolyser to produce gas hydrogen which is cheaper than the equivalent (in terms of energy content) natural gas, then the full electrolyser capacity is utilized, otherwise the electrolyser is switched off.

Note that the intermittent electrolyzer operation shown in Figure 4.7.5 corresponds to approximately 1'852 full hours of operation. The reason for this seemingly low value is that it makes economic sense to produce hydrogen only when electricity price is low. It is worth noting that a value of ~2'000 full-load hours of electrolyser operation has also been reported in other studies [14].

In addition to following the electricity price dynamics, two technical constraints inhibit the utilization of the electrolysers. First, a maximum storage capacity of the gas network equal to 10 MWh has been utilized in this study. This, together with the gas demand at every hour, obviously limits the amount of hydrogen that can be absorbed at any moment. This is shown in Figure 4.7.6, where it can be observed that, in the summer, hydrogen tends to be produced (and stored in the gas network) to the maximum possible value, profiting of cheap available electricity.

Second, let us remind here that we have introduced a constraint in the planning software which prevents that more than 20% of the gas pipeline is filled with hydrogen. As illustrated in Figure 4.7.7, this constraint limits the amount of hydrogen that can be received in the autumn-winter period, when the gas demand is higher. Note that the metric utilized in Figure 4.7.7 is a linear approximation of the actual physical constraint which is nonlinear and hence not directly accommodate-able by the utilized optimal planning software as explained in Appendix 8.

Closing this section, it is important to point out that, as illustrated in Figure 4.7.5, the problem dynamics call for an intermittent utilization of the electrolyzer capacity, driven by the electricity price variations. It is beyond the scope of the project to investigate the technical capabilities of the electrolyzer technologies, however it should be noted that this might affect the suitability of certain electrolyser technologies. For instance, PEMEC electrolyzers are claimed to be able for a more flexible operation compared to the cheaper AEC ones [15]. However, the hourly resolution ramping required in this study is also within the technical capabilities of the latter.

[17]This scenario is shown in the upper-left plot of Figure 4.7.4. The reader should bear in mind that this figure shows the total electrolyser capacity to be installed during the considered 40-year horizon. Since electrolyser capacity that gets build in 2030 is not anymore available in 2050 (due to lifetime expiration), this total invested capacity should not be interpreted as the capacity that was available in 2050, which is the year to which Figure 4.7.5 corresponds. In 2050, 2.64 MW of electrolyser capacity is in operation.

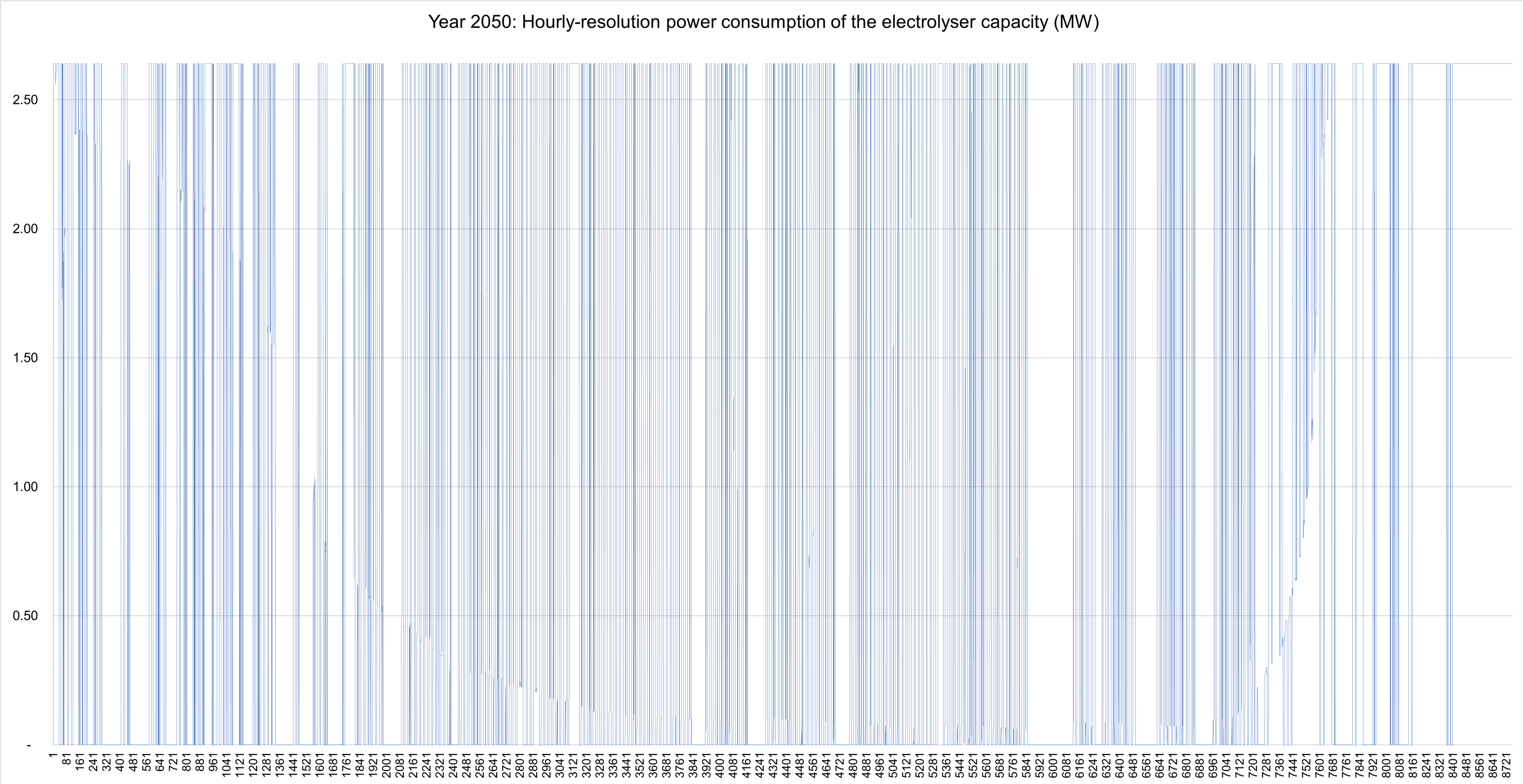

Figure 4.7.5: Hourly-resolution power consumption of the total electrolyser capacity in 2050.

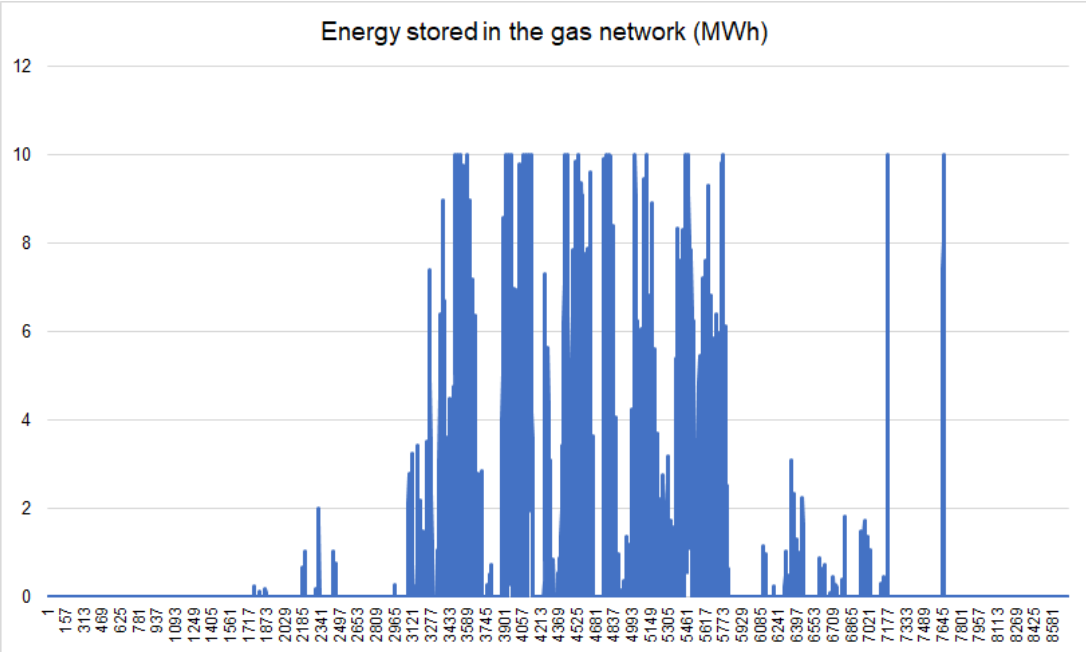

Figure 4.7.6: Energy stored in the gas network, in hourly-resolution, for the entire 2050. Note that it is assumed that a total of 10 MWh of gas energy content can be stored in the gas network.

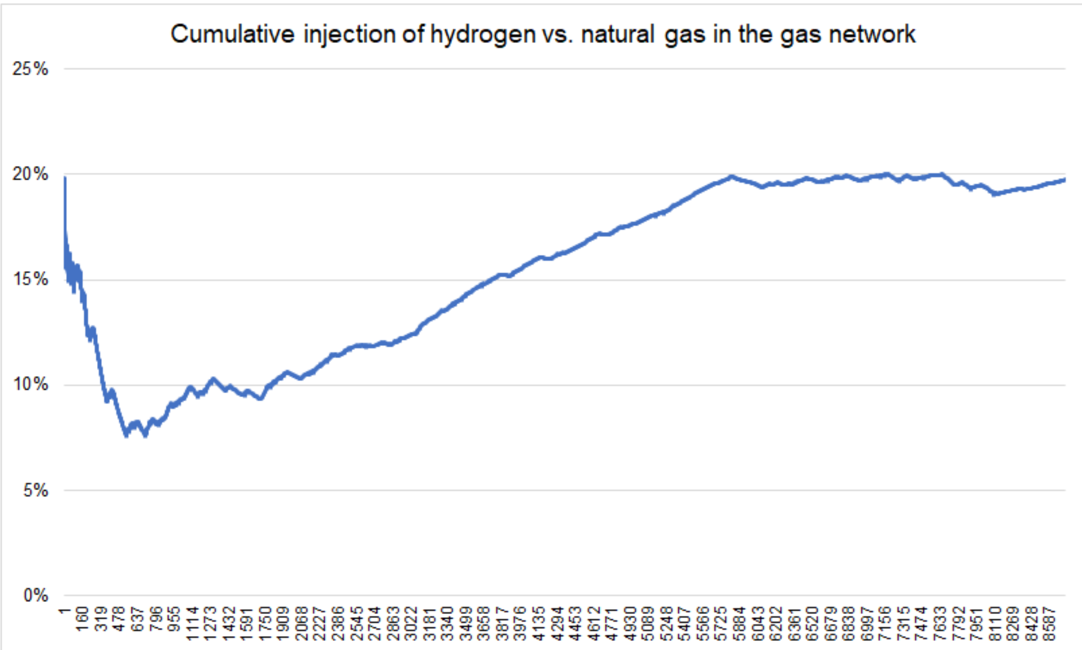

Figure 4.7.7: Metric approximating the percentage of hydrogen vs the total amount of gas that is in the gas network, in hourly resolution, for the entire 2050. Note that 20% is the maximum acceptable limit considered in this study.

4.8 Sensitivity analysis on value of utility-scale technologies: Batteries

Figures 4.9.1 and 4.9.2 present the results from performing a similar sensitivity analysis, this time emphasizing on the amount of battery capacity that should be installed according to the optimization. Both figures show sensitivities with respect to the electricity price scenarios. In Figure 4.9.1, the demand and PV installation scenarios are fixed to the "Reference" ones (see corresponding tables in Section 3), while, in Figure 4.9.2, five different Demand-PV scenario combinations are presented for the "Bat-Low" battery scenario.

Note that each figure shows both the total power and the energy capacity of the installed batteries.

The following observations can be made:

1. As expected, installation of battery capacity is clearly driven by the electricity price variability. Only the scenarios with increased standard deviation of the electricity price motivate investment in battery capacity.
2. The cost of batteries needs to be low enough in order for the aforementioned arbitrage to make up a profitable business case. In our simulations, batteries get installed only in 2050 and only for the "Bat-Low" scenario, i.e. only when/if the battery CAPEX falls to 100 CHF/kWh.
3. When battery capacity is installed, this happens at a relatively high quantity (a few hundreds of MW-hour-capacity). We observe that the typical required storing duration is 5 hours.

It is noteworthy that in the "Reference demand"-"Reference-PV" scenario pair, in the case of "Bat-Low" and "High Std" battery cost and, respectively, electricity price scenarios, a total of 312 GWh cycle through the installed battery capacity in 2050, producing a total of 265 GWh (the difference from the 312 GWh value corresponds to losses in the battery). This is 68% higher than the total demand in 2050 (which, in the "Reference" demand scenario, equals 158 GWh). Batteries are installed to perform wholesale electricity price arbitrage.

Following, we perform more granulated sensitivity analysis, where more scenarios have been considered regarding the electricity price variability and the battery investment cost, as shown in Tables 3.3.3 and 3.4.2. The analysis is performed for all the combinations of the "Reference", "Mild Gas" and "Electric" demand and "Reference", "Moderate" and "High" PV penetration scenarios. Figures 4.9.3 - 4.9.5 (each corresponding to a different battery-CAPEX scenario, namely "Bat-Low", "Bat-Low-Med" and "Bat-Med" defined in Table 3.4.2) show the optimal amount of battery capacities as resulted by the optimization problem, while Figures 4.9.6 - 4.9.8 show the corresponding investment and resulting operating costs. One can observe that investment in batteries results in lower operating cost. The reason for this is that batteries allow the utility to buy electricity when it is cheaper and utilize it to serve its customers' demand or even sell it back to the wholesale market when electricity is more expensive, thus significantly reducing its cost of electricity purchase (which makes up the most significant part of the operating cost).

High electricity price variability is required in order for a battery investment to be worth it for energy arbitrage purposes. A standard deviation value close to or above 35 CHF/MWh seems being a reasonable cut-off point. Also, Battery CAPEX (CHF per kWh of storing capacity) needs to considerably fall, compared to today's level) to make batteries an economically interesting investment (driven by electricity price differences). A value below 200 CHF/kWh seems being a reasonable rule of thumb. Of course, it strongly depends on the electricity price variability. In all cases, the optimizer proposes battery investments to take place only in year 2050, when, in some scenarios, electricity prices are variable enough. A 5-hour battery storage duration is a typical optimal size.

The other parameters of the sensitivity analysis have smaller effect on the result. Precisely, it can be observed that lower mean value of the electricity price and higher amount of PV penetration motivate investment in batteries, while the demand scenario seems playing no role in the result. Note that the result of this analysis is not driven by congestions in the local distribution grid, which is able to accommodate the power flows resulting from the Demand and PV scenarios as shown in Section 4.1.

Specifically in what concerns the fact that lower mean value of the electricity price resulted, for a given value of standard deviation, into somewhat higher amount of investment in batteries, it is important to emphasize that this is due to the way that electricity price scenarios were created; for each standard deviation value, there is a "reference" and a "low-mean" electricity price scenario. As a result, in each low-mean-value scenario a battery can offer a higher relative profit for charge-discharge cycle compared to its corresponding reference-mean-value scenario.

Depending on the aforementioned boundary conditions, large investments in batteries (even >100 million CHF) can be justifiable, resulting into reductions in the operating costs of similar order of magnitude.

As a side remark, it is worth noting that, in all cases, the operating cost decreases as we move from the "Moderate" PV scenario to the "Reference" and eventually the "High" PV scenario (which has the lower operating cost). This can be observed in Figures 4.9.6 - 4.9.8. This is expected, since the higher the PV penetration the lower the required electricity purchase (see Figure 3.1.3 for an indication of the potential reduction). However, by comparing the decrease in operating cost with the total customer-side investment cost that is required to achieve a certain PV penetration scenario (per Figure 3.1.4), one can observe that for all the considered electricity price scenarios the total investment costs are higher than the potential savings. This indicates that "the market" might not be able to drive such high PV investments. Let us note however, that such an analysis goes beyond the scope of this project, as it is dependent on the assumptions made about the future wholesale electricity prices.

4.9 Sensitivity analysis on value of utility-scale enabling technologies: Fuel Cells

Finally, the same type of sensitivity analysis has been performed for the case of fuel cells. However, contrary to the case of electrolysers and batteries, no combination of scenarios has led to a need for fuel cell capacity. Even in the case of the "Cheap" and "SuperCheap" scenarios (see Table 3.4.3, there are no economics that would make valuable the installation of fuel cell capacity, which would allow to convert gas to electricity.

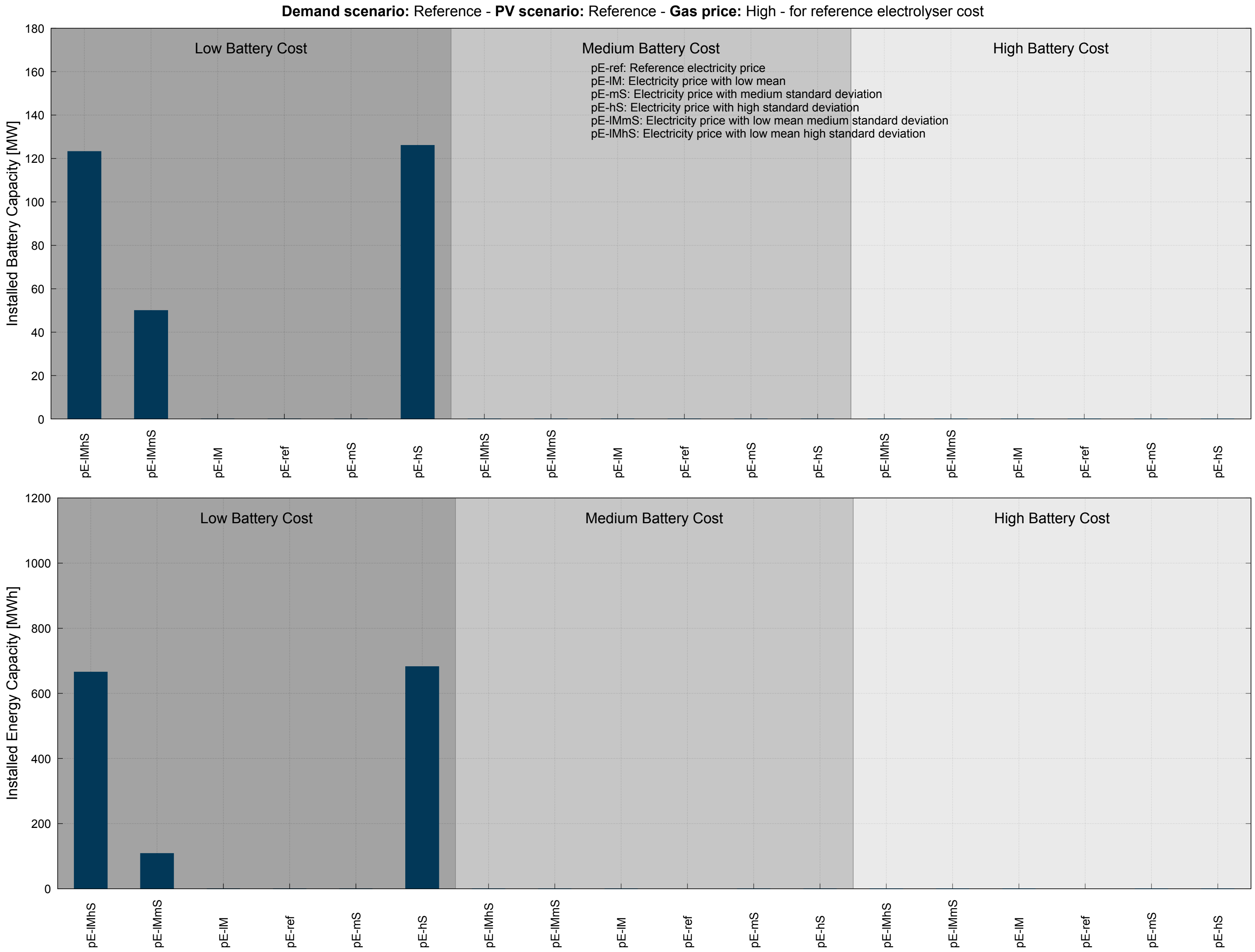

Figure 4.9.1: Sensitivity analysis performed for the pair "Reference demand scenario" - "Reference PV scenario". Absence of a bar denotes that the value is zero. Absence of a bar denotes that the value is zero.

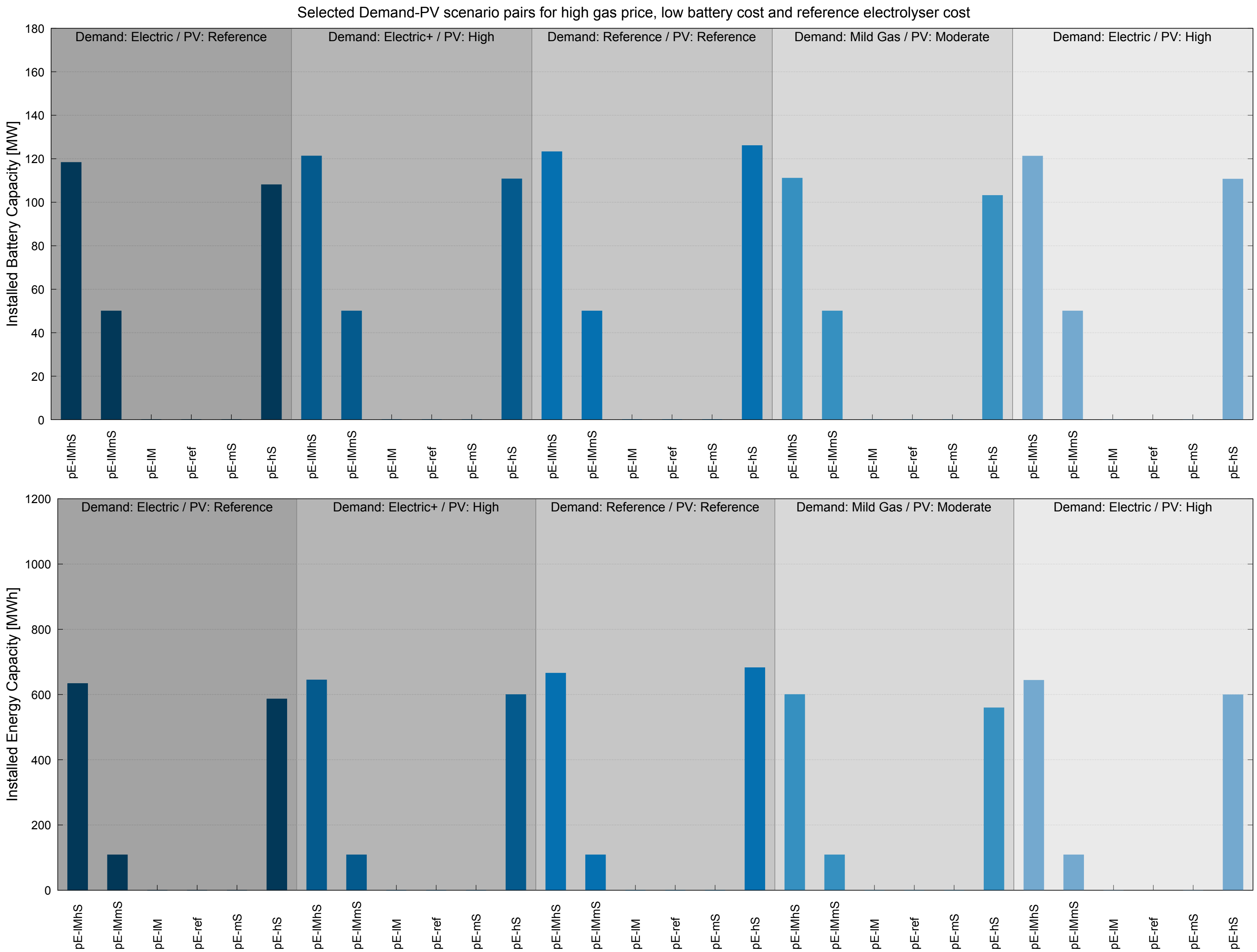

Figure 4.9.2: Sensitivity analysis performed for five different Demand-PV scenario pairs. The "Low-Bat" scenario is used.

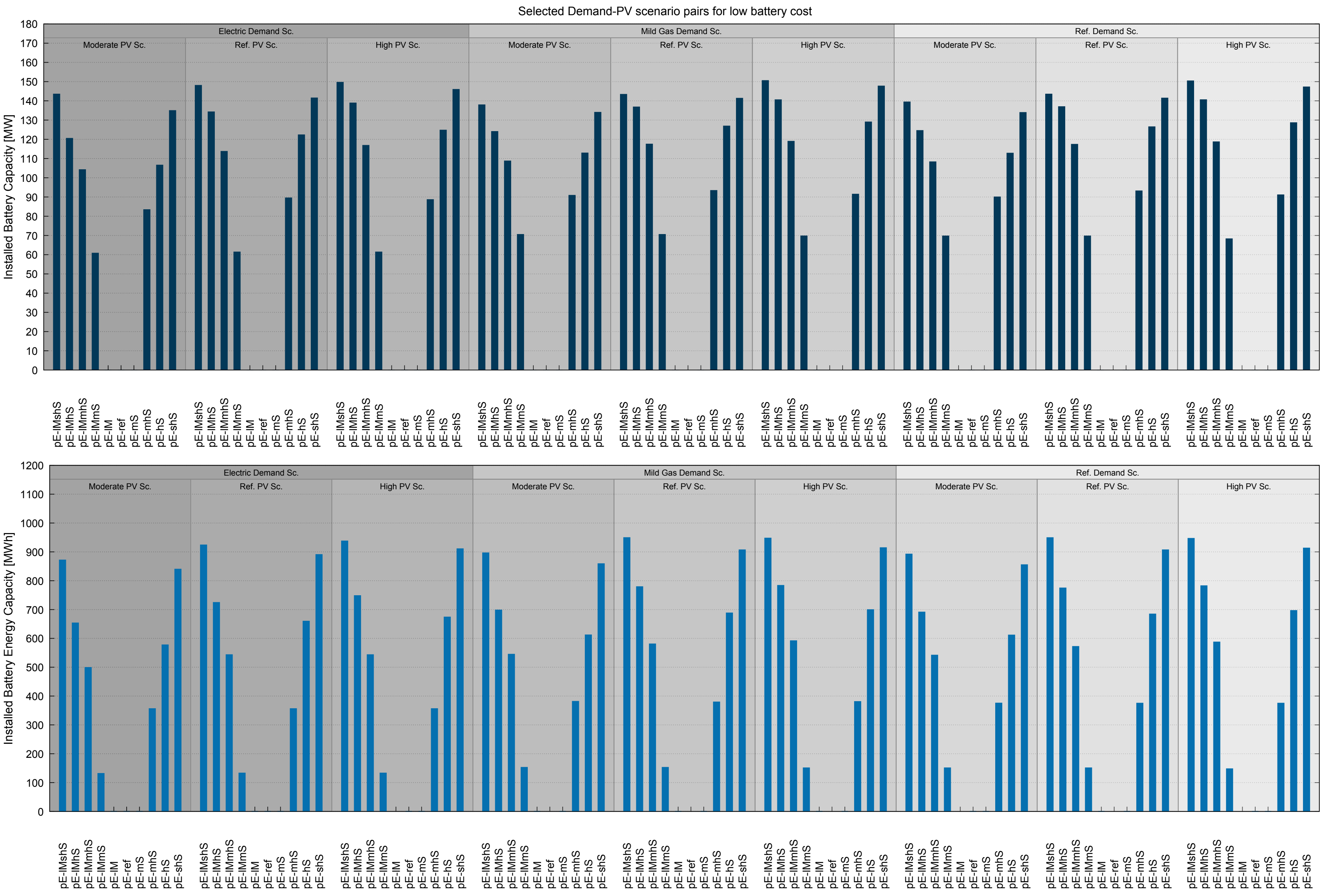

Figure 4.9.3: Outcome of the optimization for various scenarios, for the "Bat-Low" scenario: Optimal investments in battery power and energy capacity. Absence of a bar denotes that the value is zero.

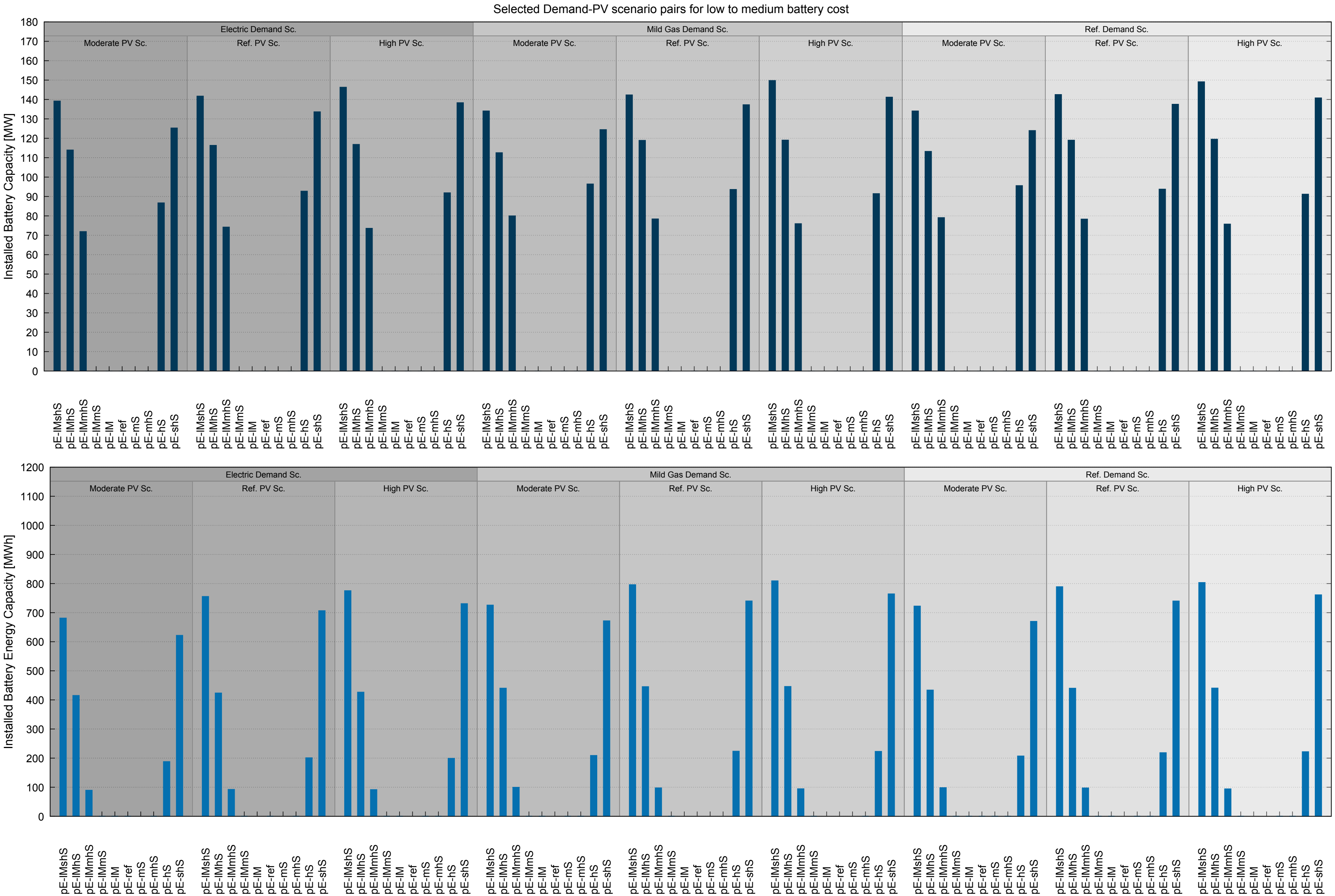

Figure 4.9.4: Outcome of the optimization for various scenarios for the "Bat-Low-Med" scenario: Optimal investments in battery power and energy capacity. Absence of a bar denotes that the value is zero.

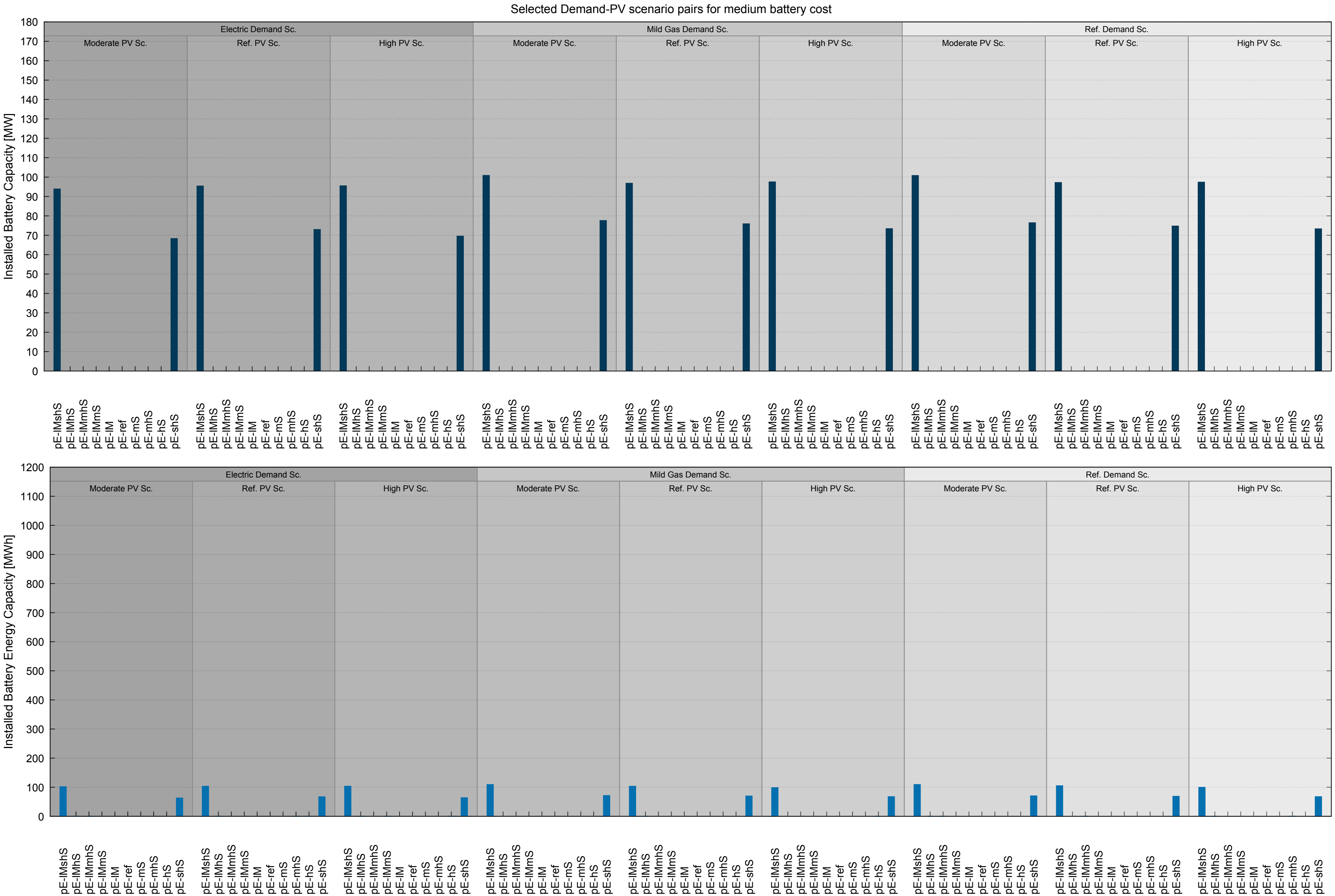

Figure 4.9.5: Outcome of the optimization for various scenarios for the "Bat-Med" scenario: Optimal investments in battery power and energy capacity. Absence of a bar denotes that the value is zero.

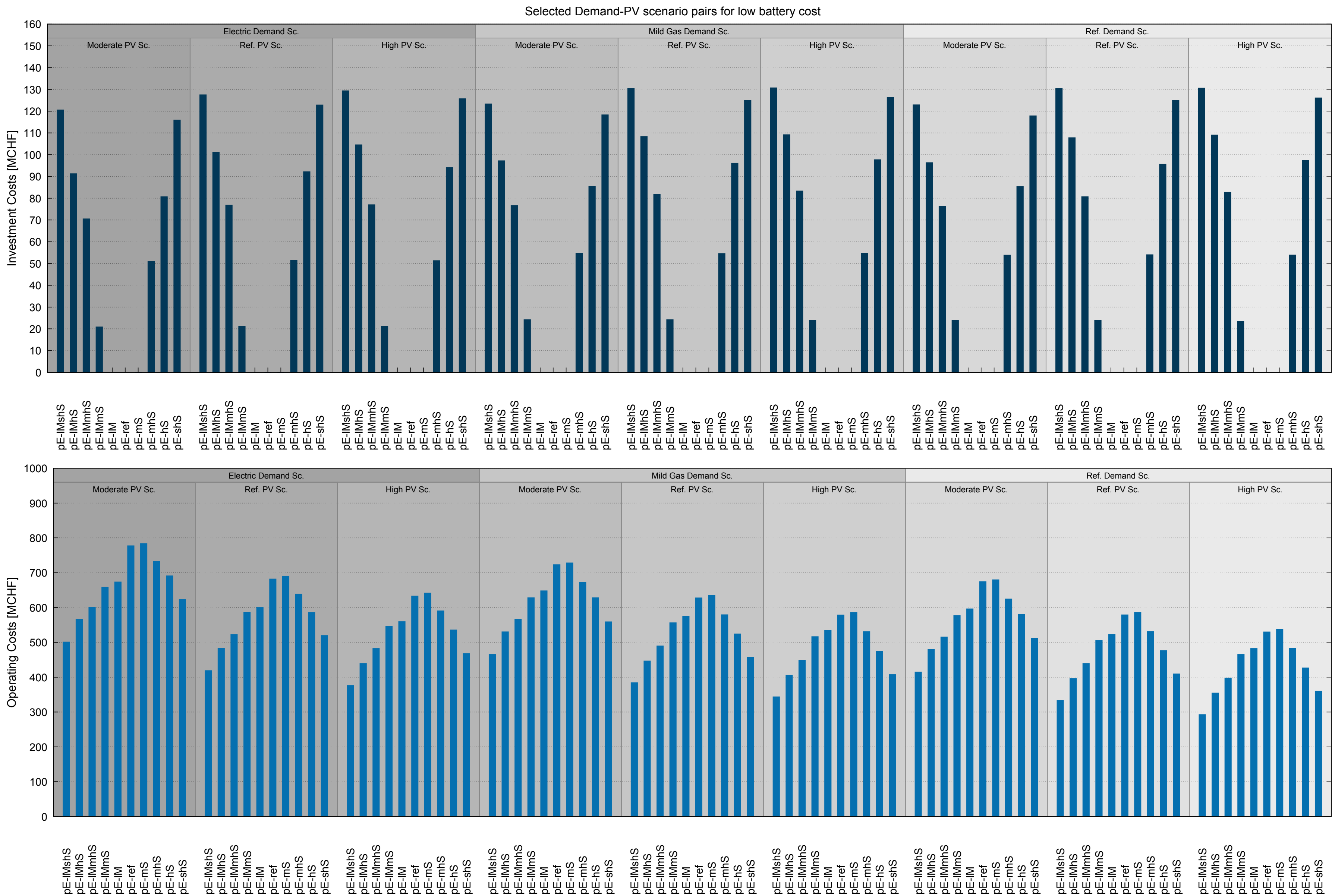

Figure 4.9.6: Outcome of the optimization for various scenarios, for the "Bat-Low" scenario: Total investment (into batteries) and operating costs. Absence of a bar denotes that the value is zero.

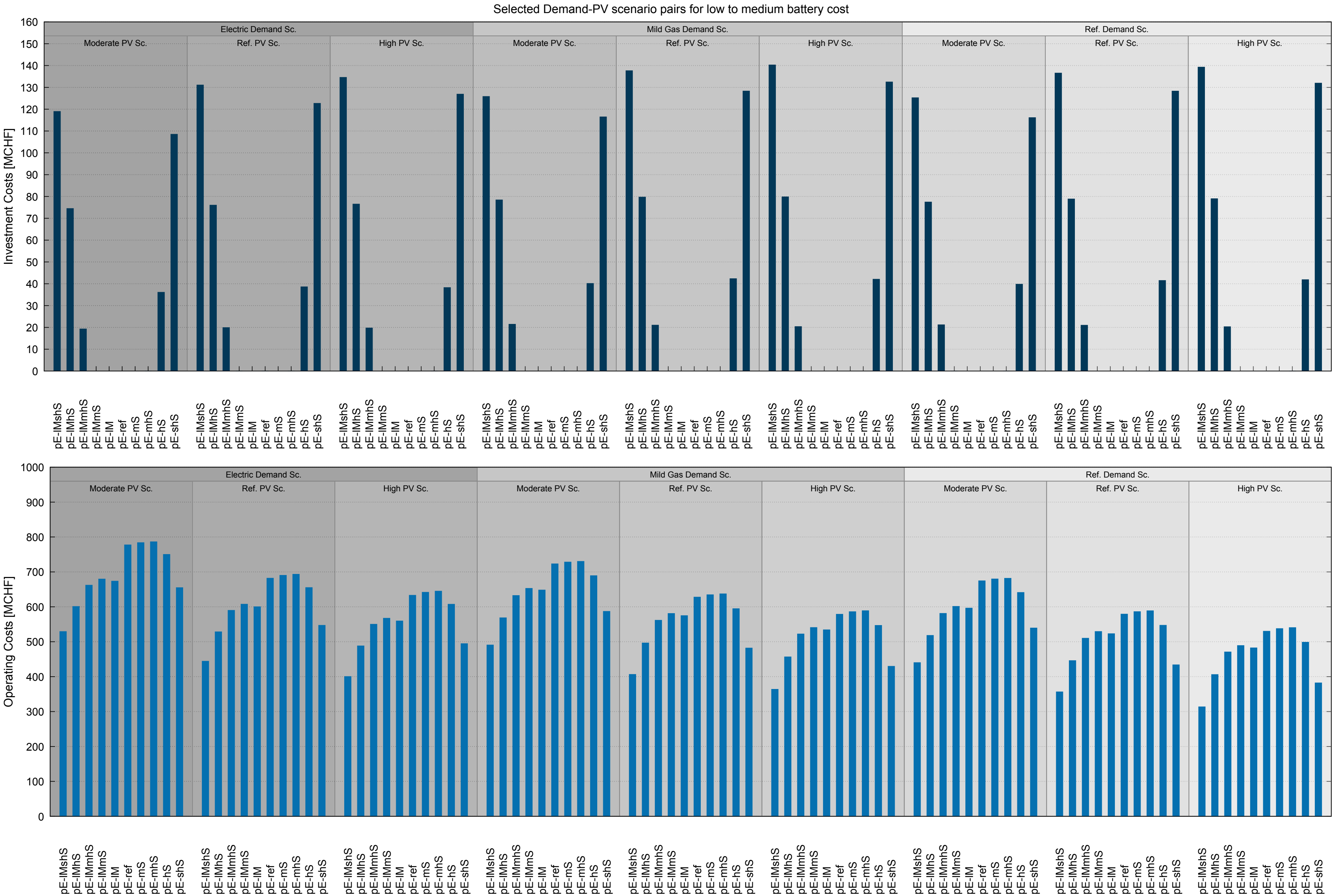

Figure 4.9.7: Outcome of the optimization for various scenarios, for the "Bat-Low-Med" scenario: Total investment (into batteries) and operating costs. Absence of a bar denotes that the value is zero.

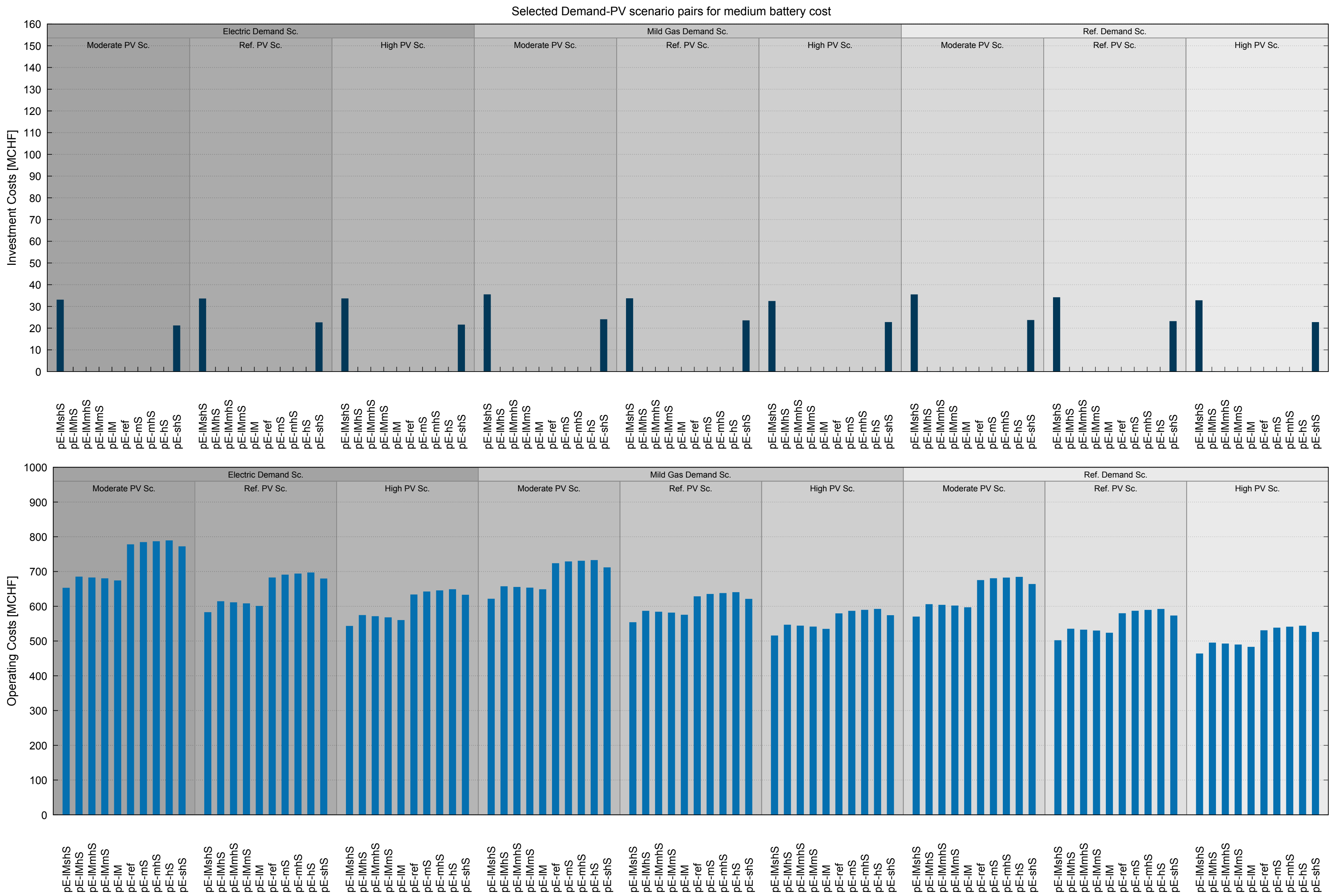

Figure 4.9.8: Outcome of the optimization for various scenarios, for the "Bat-Med" scenario: Total investment (into batteries) and operating costs. Absence of a bar denotes that the value is zero.

4.10 Sensitivity analysis on value of utility-scale enabling technologies: Are there inter-dependencies between installed electrolyzer and battery capacities?

As a recap, Figures 4.10.1 and 4.10.2 summarize the resulting electrolyzer and battery invested capacities for the five selected Demand-PV scenario pairs and for the considered electricity price scenarios. The "AEC-Low" electrolyser CAPEX, "Reference" CO2 tax and "Bat-Low" battery CAPEX scenarios are used to produce these figures.

Note that the reader should not compare the amount of battery investments with the amount of electrolyser investments, because they are not directly comparable because the amount of the latter (electrolysers) is constrained by the limited demand for gas (and the fact that only 20% of this demand can be served by hydrogen, as already discussed). These graphs are shown together, so that the reader can observe the relative impact of various scenarios on battery and on electrolyser investments.

Following an analysis of all the results of the sensitivity analysis, it has been observed that there are no cause-and-effect relationships between the two technologies. More or less installed capacity of one technology (driven for example by the technology cost) does not affect the optimal installed capacity of the other technology.

Two light correlations can be however observed, driven by a third root cause which has an impact on the value of both technologies, and hence their resulting installed capacities:

- A positive correlation: Both technologies react positively to increased variability of the electricity price. For the case of battery, this is the main condition under which it has value. For the case of electrolyser, the relationship is less strong; it is not the variability itself which creates value but rather the fact that, in those price scenarios, electricity price takes lower values more often.
- A negative correlation: Both technologies are impacted by the extend to which a more or less "electrification" scenario is followed. Electrolyzer is more valuable when there is a consistent gas demand to serve, while batteries are more needed in a scenario with higher amount of electrification, mainly because they can store excess PV power in moments of negative electricity prices.

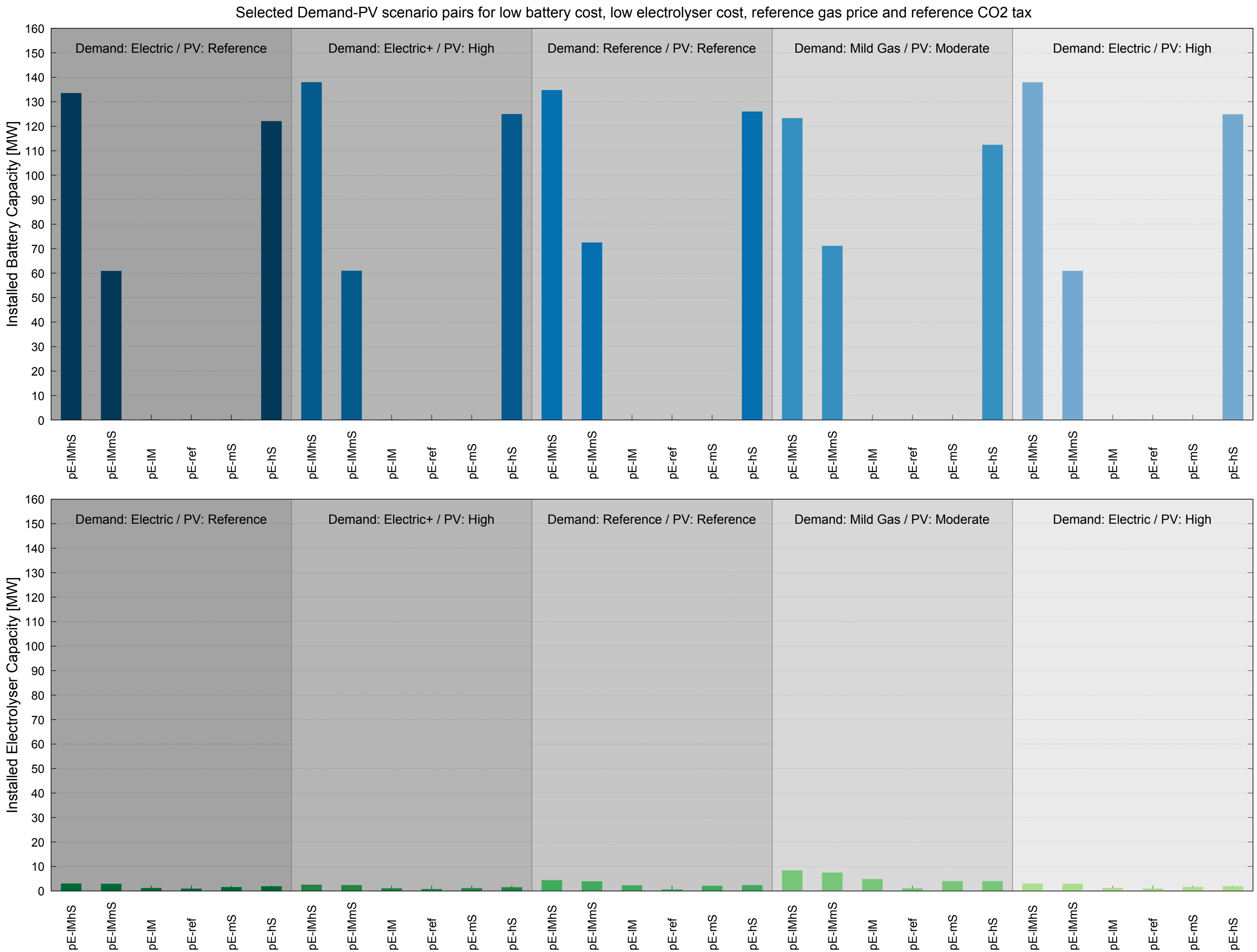

Figure 4.10.1: Summary of selected sensitivities with respect to investments in battery and electrolyser capacities, for the "Reference" gas price scenario. Absence of a bar denotes that the value is zero.

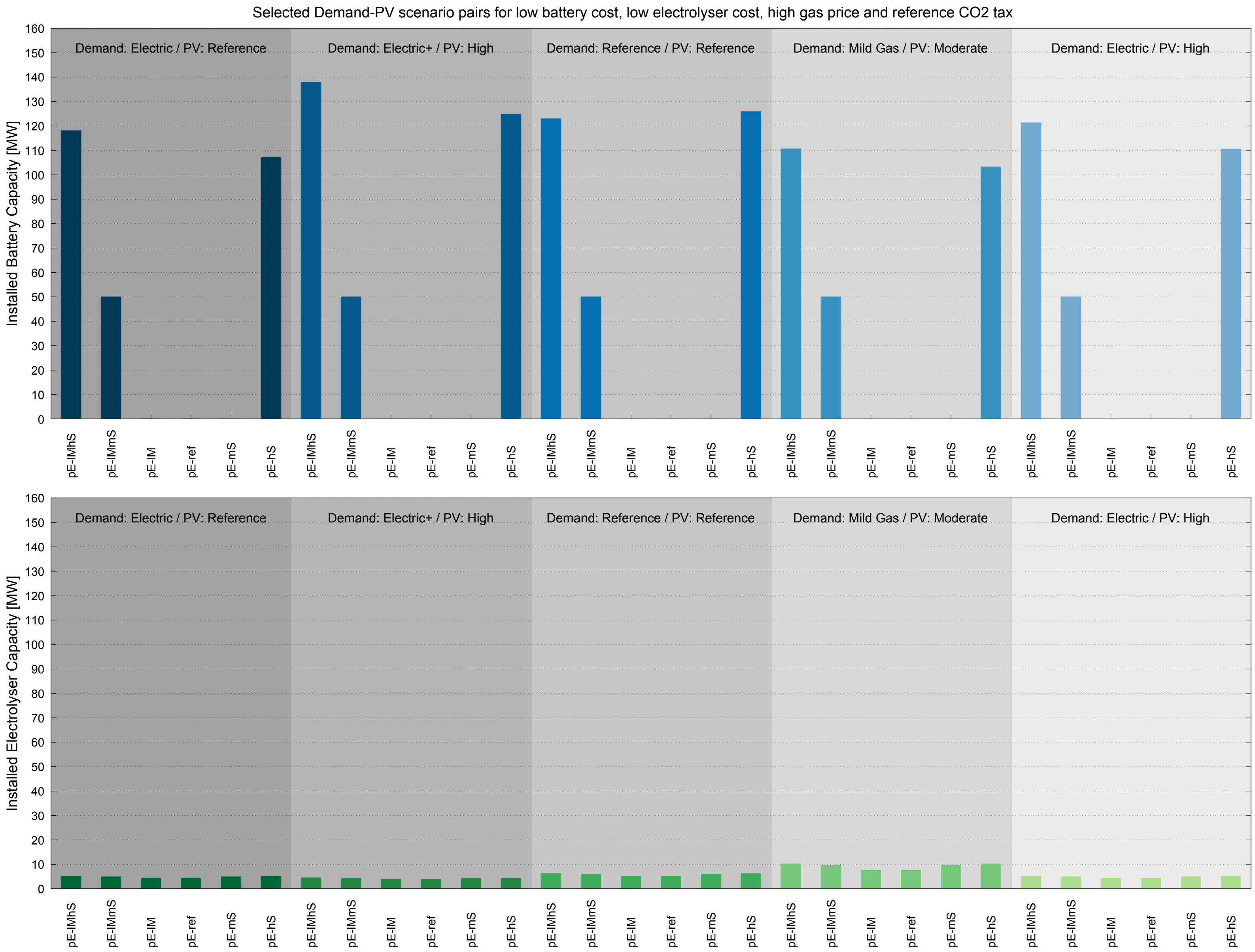

Figure 4.10.2: Summary of selected sensitivities with respect to investments in battery and electrolyser capacities, for the "High" gas price scenario. Absence of a bar denotes that the value is zero.

4.11 Boundary conditions for H2 storage to make up a valuable option

In this section, the potential value of investing into H2 storage capacity is investigated and quantified. To this purpose, we perform sensitivity analysis, considering the amount of H2 storage capacity that is installed in the utility territory as an exogenous input to the optimization problem. That is, optimal investments in enabling technologies (electrolyzers, batteries) are identified to minimize the total cost of operating the combined electricity and gas system. The predefined amount of H2 storage capacity is utilized in an optimal manner as part of the overall optimization.

Figures 4.11.1 and 4.11.2 show the resulting optimal amount of electrolyzer capacity for different Demand, PV and electricity and gas price scenarios and different exogenously assumed H2 storage installed capacities (in the x-axis of the plot). The naming convention for the latter is as follows: 20M denotes 20MWh storage capacity, 500M stands for 500 MWh and so on, with 10G standing for 10 GWh of H2 storage capacity. The second term in the "H2-storage scenario" label denotes the fact that, at any given moment, only up to a 20% fraction of the gas network pipelines can be filled with H2, the remaining (80-100%) being necessarily methane (natural) gas. One can observe in the figure that adding more available H2 storage capacity has a minimal (if not at all) impact on the amount of electrolyzer capacity that is worth investing in.

It can be observed in Figures 4.11.3 and 4.11.4 that the operating cost is not decreased if the utility has the capacity to store hydrogen. This is due to the 20% constraint of the gas network; even if H2 can be stored in large quantities, thus potentially allowing the utility to produce H2 in moments of low electricity price, there is very little demand for H2 because of the fact that at least 80% of the, anyway reduced, demand for gas needs to be covered by natural gas, due to the aforementioned constraint. As a result, investment in H2 storage would only add to the total cost, as shown in 4.11.3 and 4.11.4 by the orange bar. A value of 500 CHF per kg of H2 has been used [21] as the H2 investment cost. This corresponds to 14.3 CHF/MWh of storing capacity. In this analysis, we assume that the H2 storage is build in 2020 (i.e. it is fully available from the beginning of the optimization horizon) and that its lifetime equals 40 years.

In order to be able to illustrate the potential value of H2 storage, we consider a hypothetical scenario where the gas pipelines are solely utilized to distribute locally produced hydrogen to customers that utilize gas H2 as a fuel for heating. In other words, in this scenario it is assumed that there is zero consumption of natural gas. For the sake of easiness of interpretation of results, we assume that this happens from 2020 on. Note that the cost of converting the gas pipelines such that they can transfer only hydrogen is not considered. As a result, it should not be seen as a completed study, but rather as a first step of a potential future analysis. The interested reader can find information relating to the cost of converting the gas network to a network exclusively dedicated to hydrogen transportation in references such as [4] and [5][18].

Figures 4.11.6 and 4.11.8 present the results of such a sensitivity analysis. Note that this family of scenarios (with the available H2 storage varying) are denoted by the suffix "fr1" in the scenario name (see x-axis of the plots). The following observations can be made:

- As expected, a considerable amount of electrolyzer capacity is built in this case. This is absolutely required, since locally produced H2 is the only means of meeting the gas demand. This is why, in the "Mild Gas" demand scenario more electrolyzer capacity is built compared to the "Reference" demand scenario.

[18] According to [5], the cost of converting an existing gas network to a network purely for hydrogen is estimated to ~10-15% of the cost of new construction.

- In most cases, we observe that the higher the amount of available H2 storage, the lower the required electrolyzer capacity. This is due to the fact that electrolyzers do not need to be dimensioned such that they can cover the peak demand for gas.
- High electricity price variability motivates larger amount of electrolyzer capacity, especially when there is "enough" H2 storage available. The reason for this is that larger electricity price differences provide higher motivation to produce more H2 when electricity is cheap and store it for use when electricity is expensive.
- As expected, higher amount of available H2 storage results in lower operating cost.
- However, too much storage does not necessarily make overall economic cost, as the corresponding investment cost might exceed the resulting saving.
- In the scenarios considered in this analysis, it turned out that H2 storage corresponding to 500 MWh - 1 GWh of energy (2'500 - 5'000 tons of H2) is the optimal choice.

Figure 4.11.9 illustrates the utilization of the H2 storage in the "Mild Gas" demand, "Moderate" PV, "High Std" electricity price combination of scenarios. The upper plot in the figure shows the amount of hydrogen that is stored in a 500-MWh storage, as it is getting charged and discharged during the year, while the lower plot shows the same information for a 10-GWh storage. Let us recall from Figure 3.1.2 that in this scenario the total annual demand for gas drops from 100 GWh in 2020 to 40 GWh in 2050. Figure 4.11.10 is a scatter-plot showing the hourly operation of the storage (positive for storing H2, negative for injecting H2 to the gas grid) in 2020 and in 2050 for the same case as in Figure 4.11.9.

One can clearly observe that 10-GWh of storage is a large enough quantity to allow for a seasonal utilization of this capacity, progressively storing H2 in the period from June until September and consuming it in winter time. The storage is slowly filled by producing hydrogen almost exclusively (in 2050) during hours of low electricity prices. On the other hand, a 500-MWh storage is mostly utilized to "smoothen" out the exposure to electricity price spikes in the shorter time horizon; it is not large enough to allow for seasonal storage.

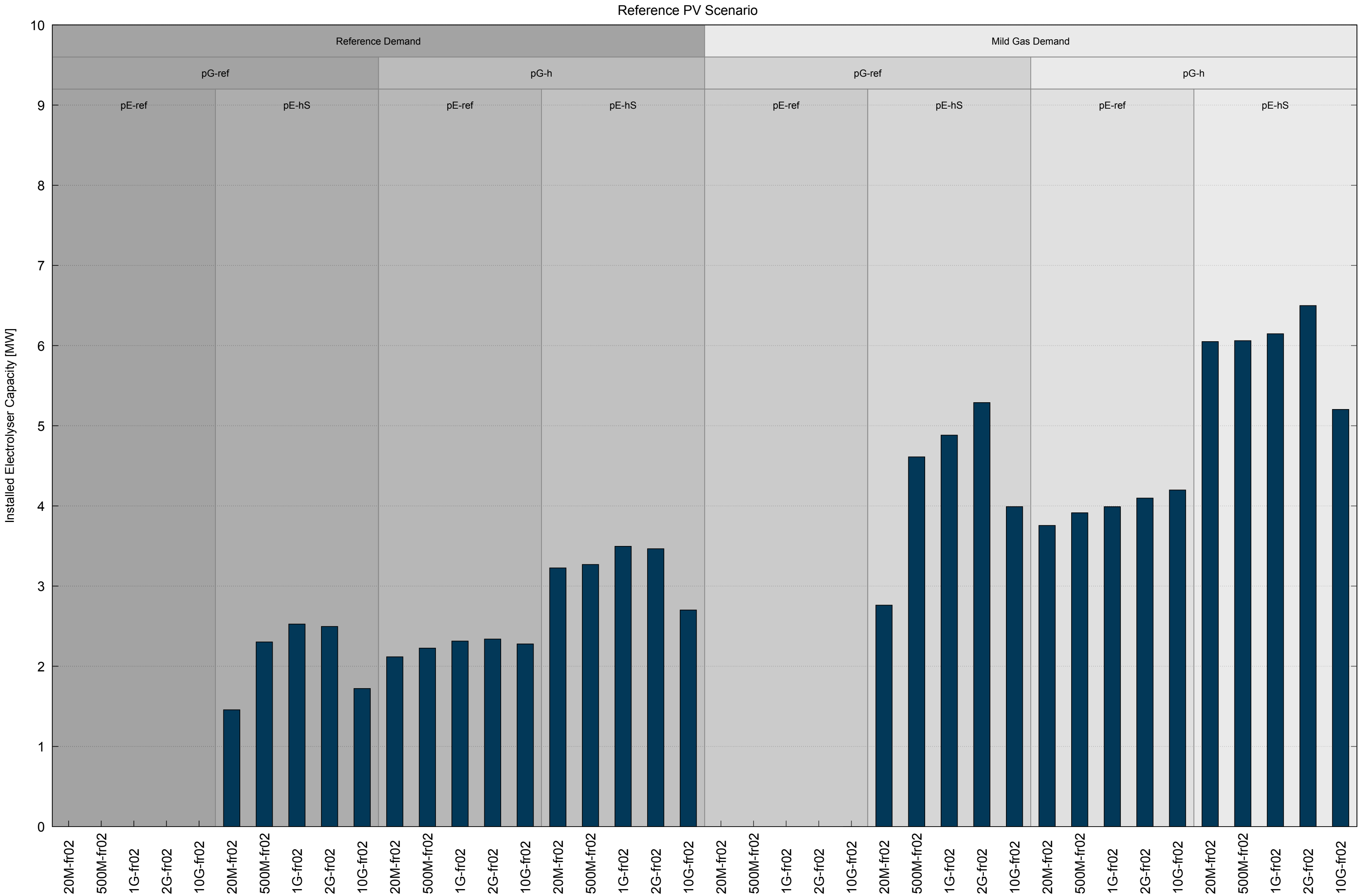

Figure 4.11.1: Outcome of the optimization for various scenarios, for various amounts of H2 storage: Optimal investments in electrolyzer capacity. Absence of a bar denotes that the value is zero.

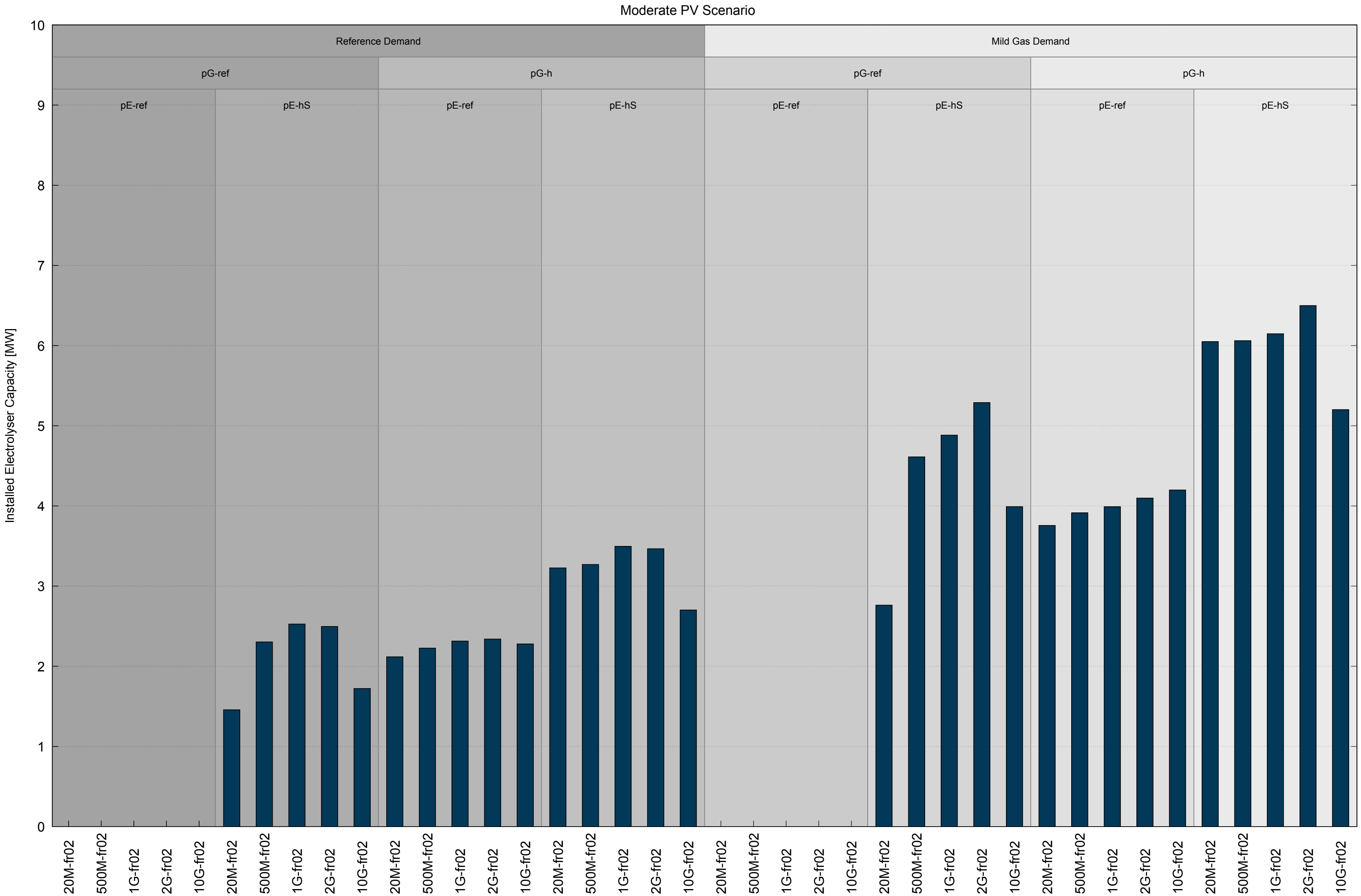

Figure 4.11.2: Outcome of the optimization for various scenarios, for various amounts of H2 storage: Optimal investments in electrolyzer capacity. Absence of a bar denotes that the value is zero.

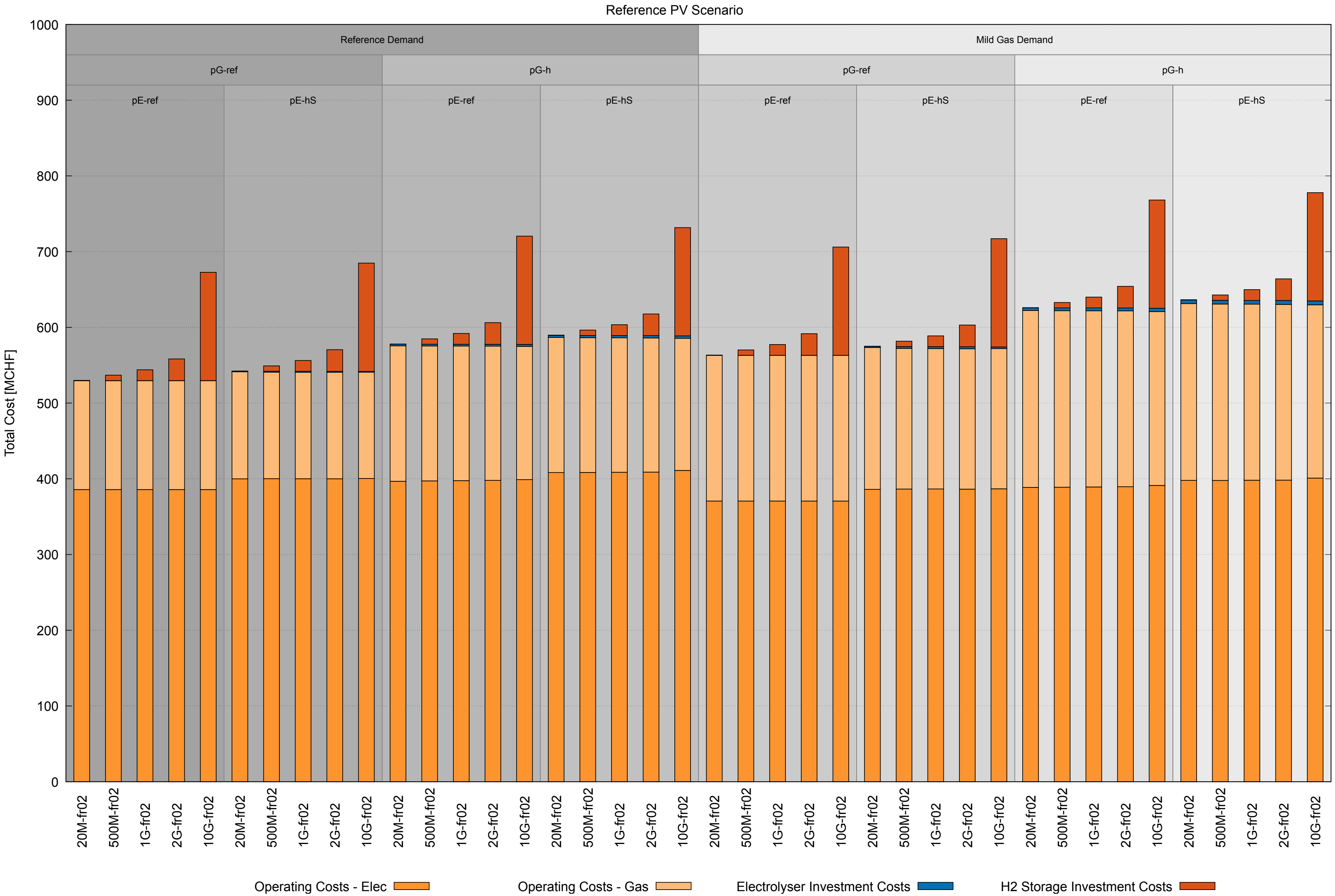

Figure 4.11.3: Outcome of the optimization for various scenarios, for various amounts of H2 storage: Total cost

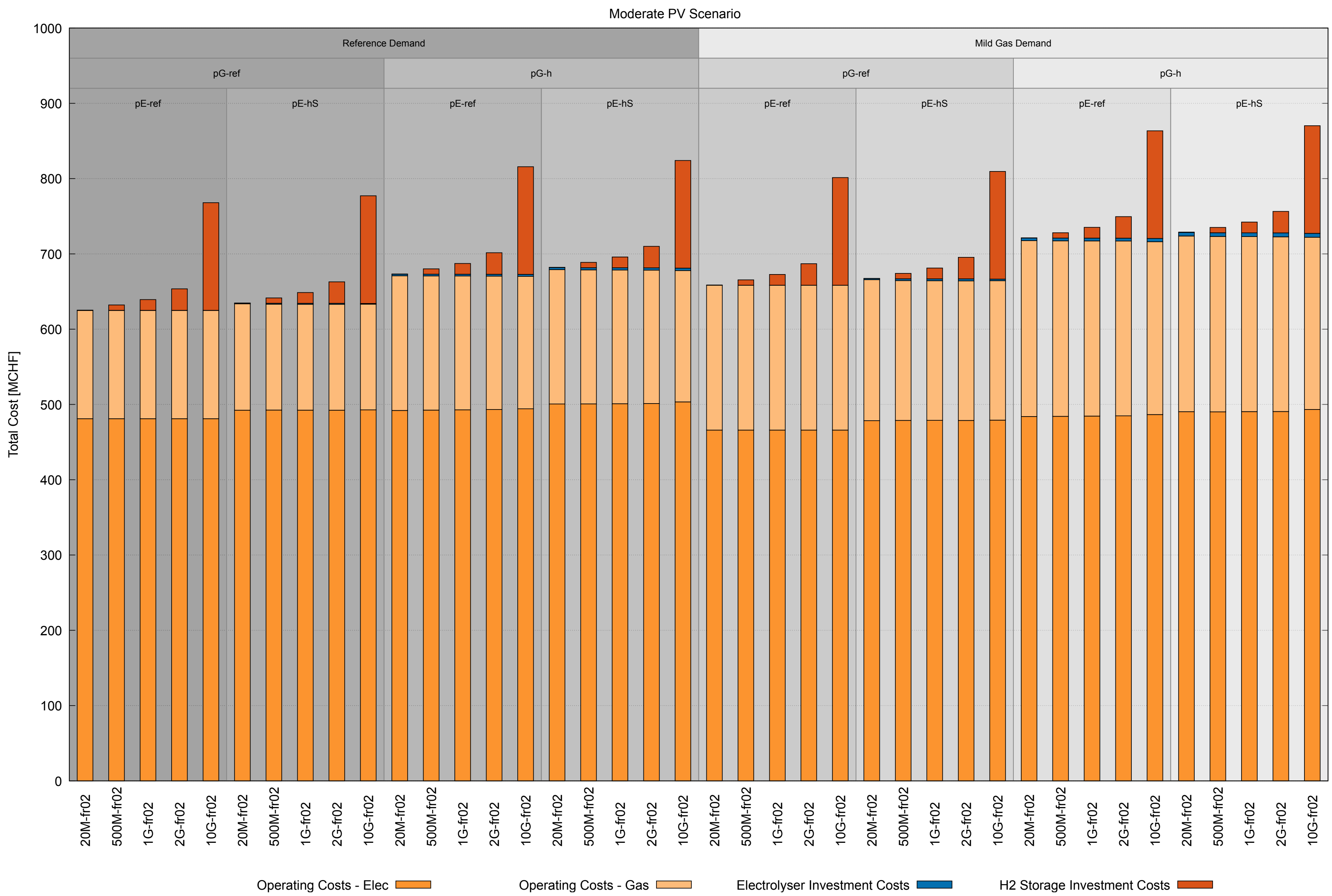

Figure 4.11.4: Outcome of the optimization for various scenarios, for various amounts of H2 storage: Total cost.

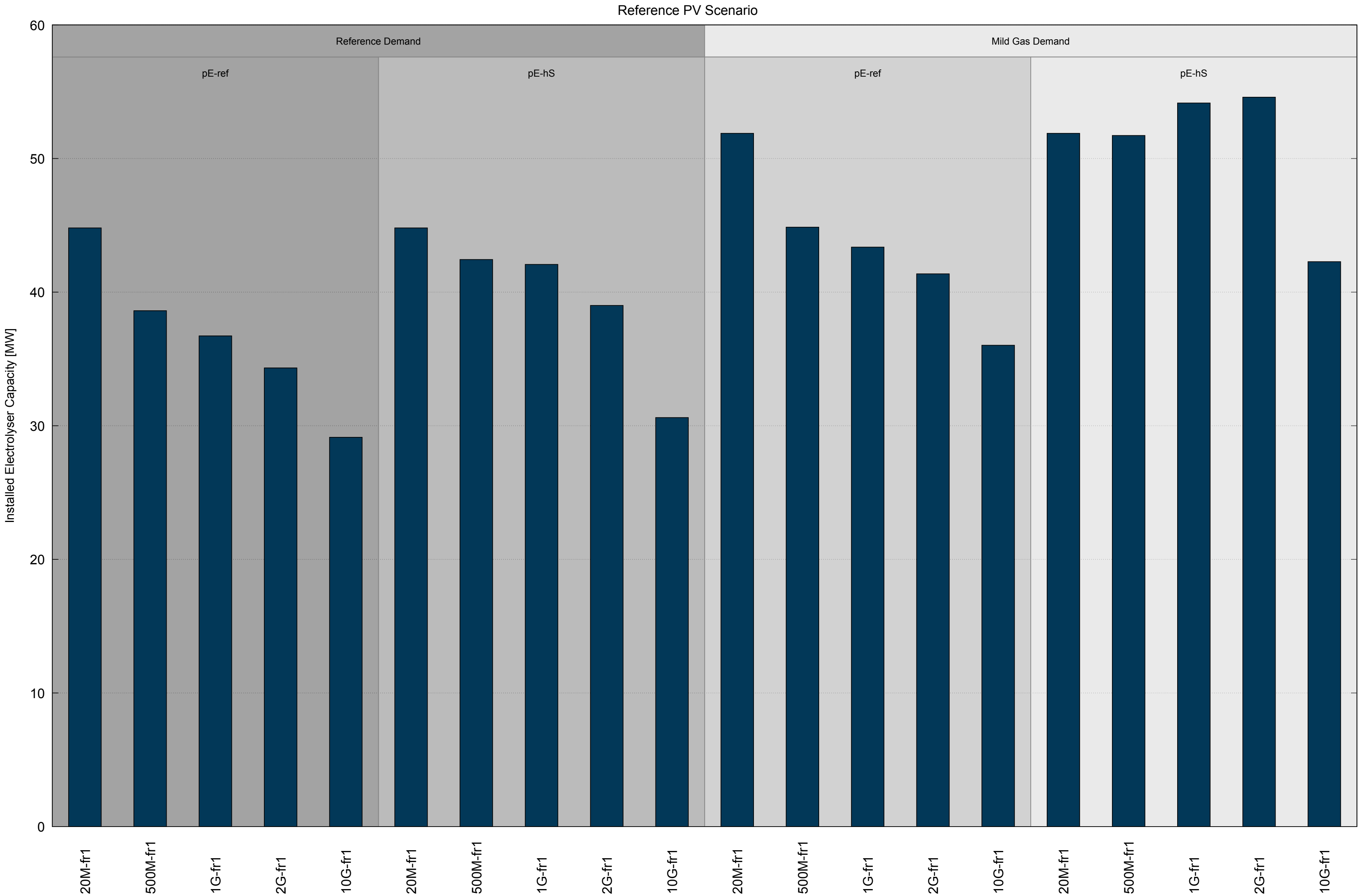

Figure 4.11.5: Outcome of the optimization for various scenarios, for various amounts of H2 storage, with the gas network carrying only H2: Optimal investments in electrolyser capacity.

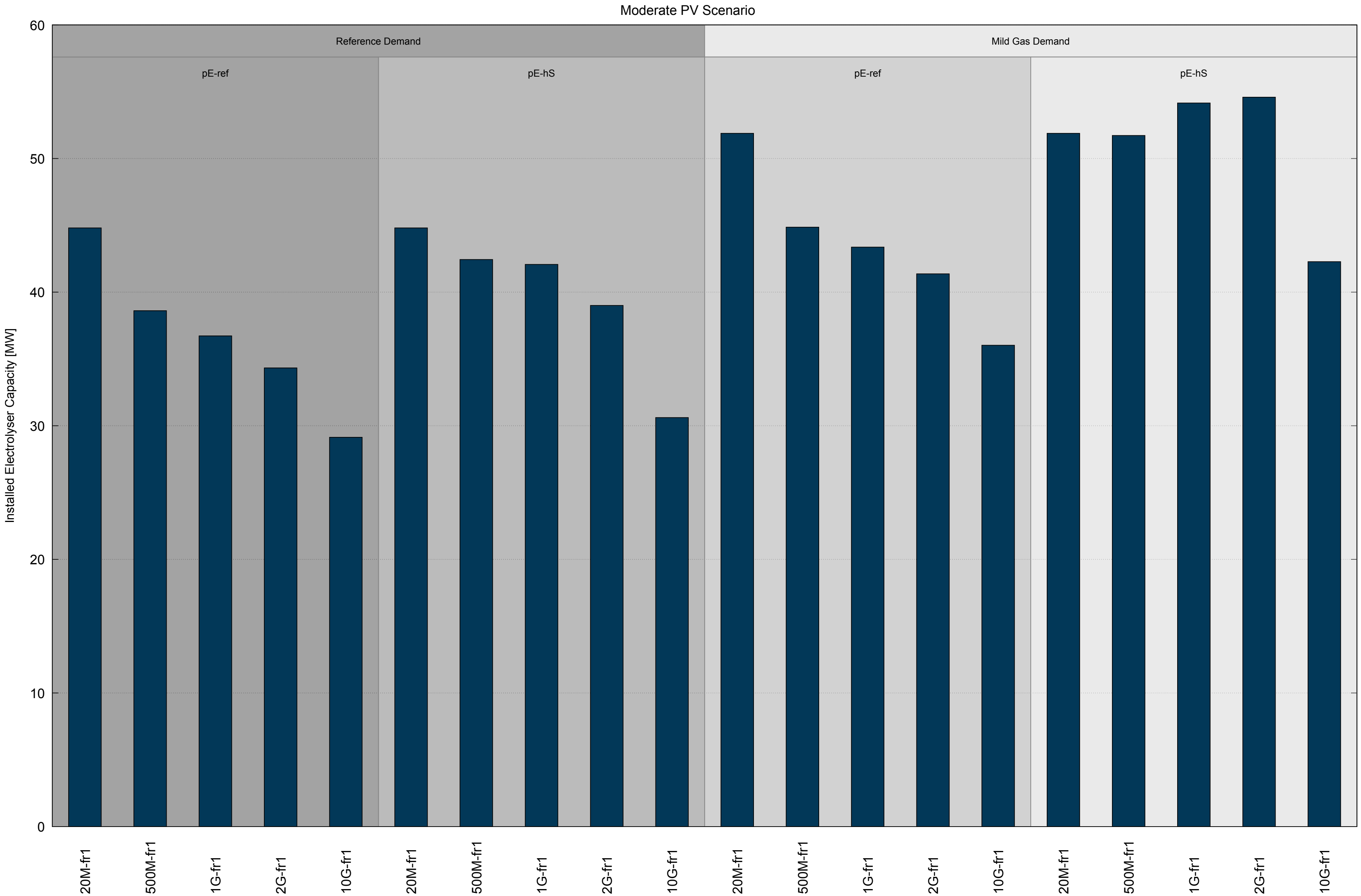

Figure 4.11.6: Outcome of the optimization for various scenarios, for various amounts of H2 storage, with the gas network carrying only H2: Optimal investments in electrolyser capacity.

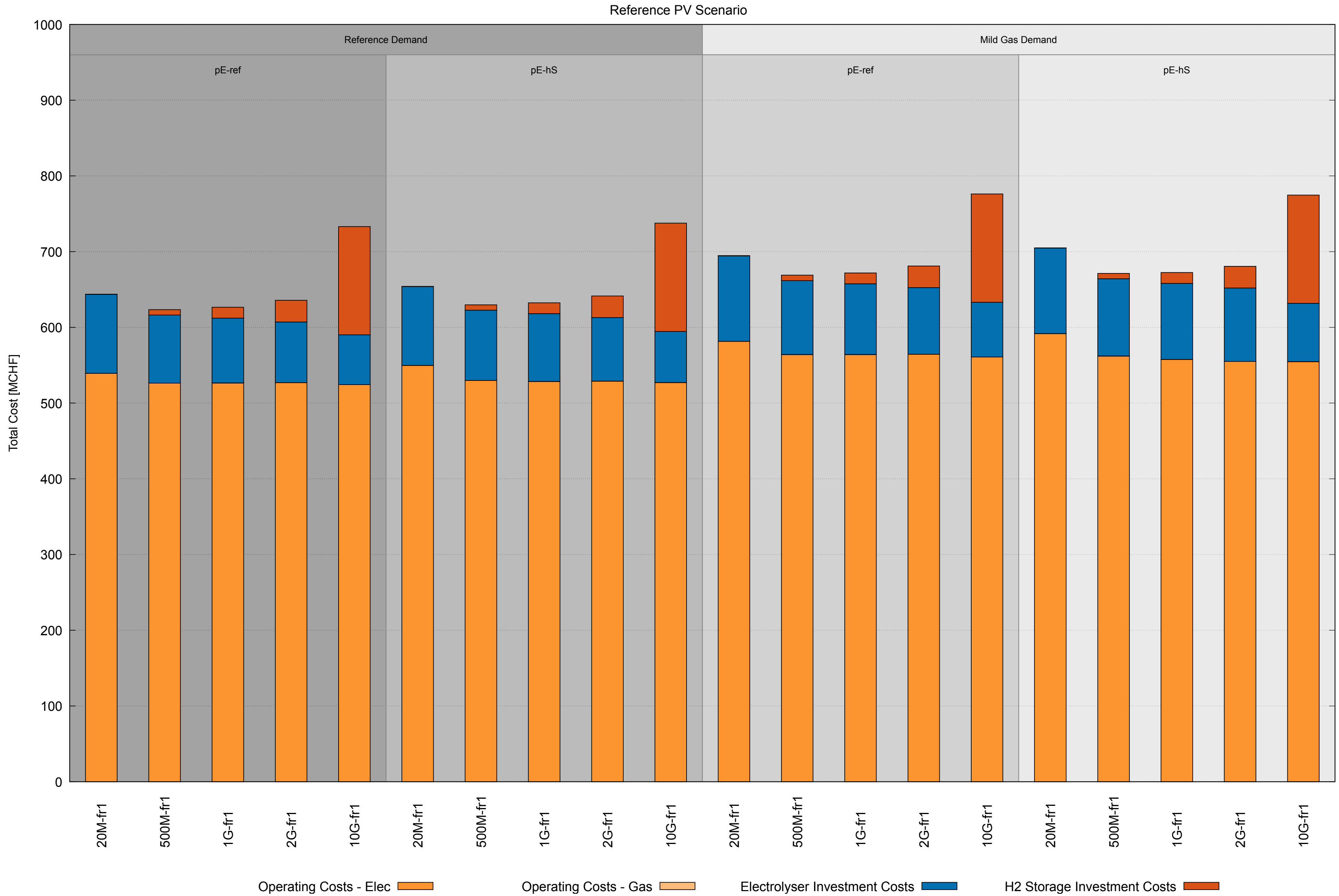

Figure 4.11.7: Outcome of the optimization for various scenarios, with the gas network carrying only H2: Total cost.

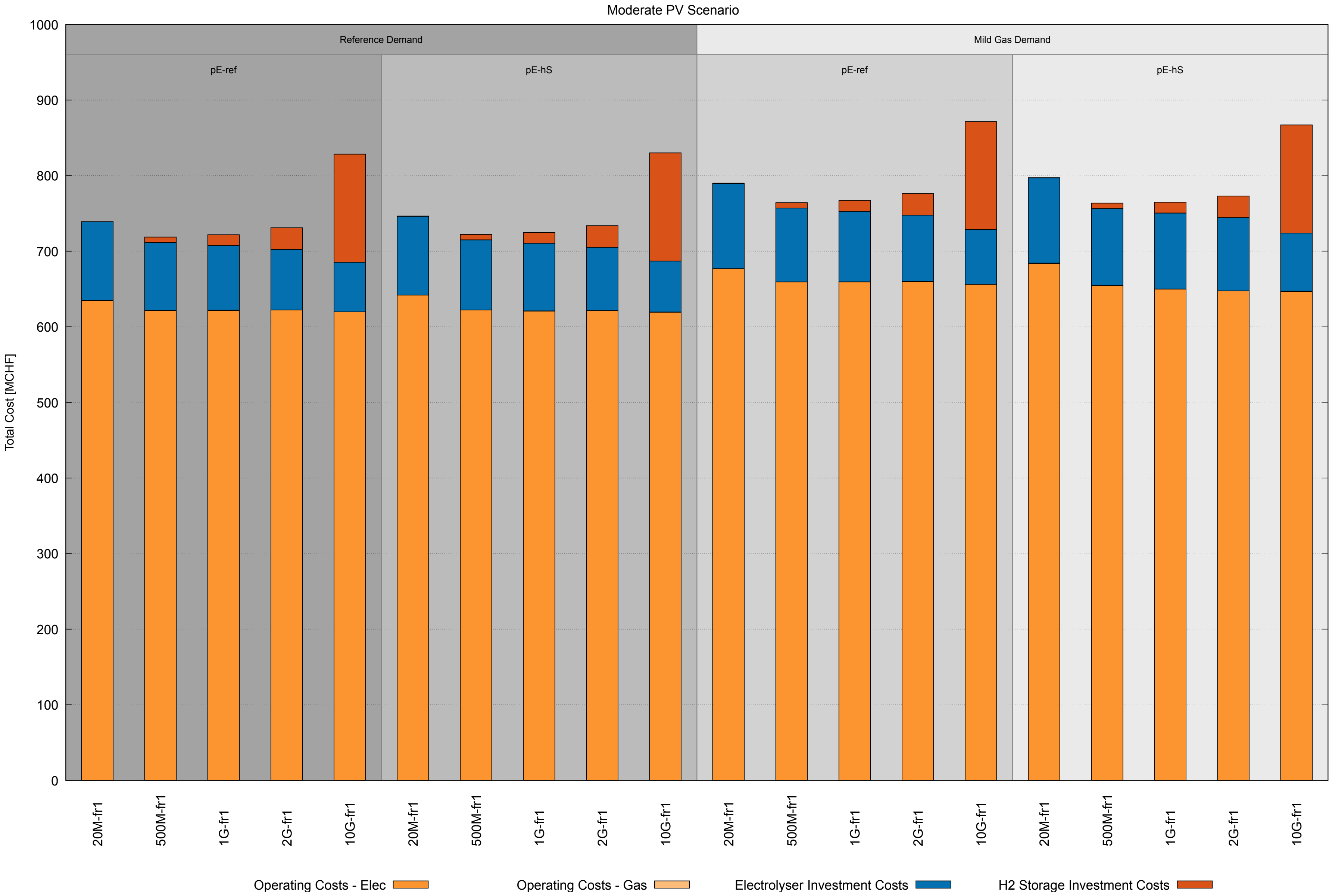

Figure 4.11.8: Outcome of the optimization for various scenarios, with the gas network carrying only H2: Total cost.

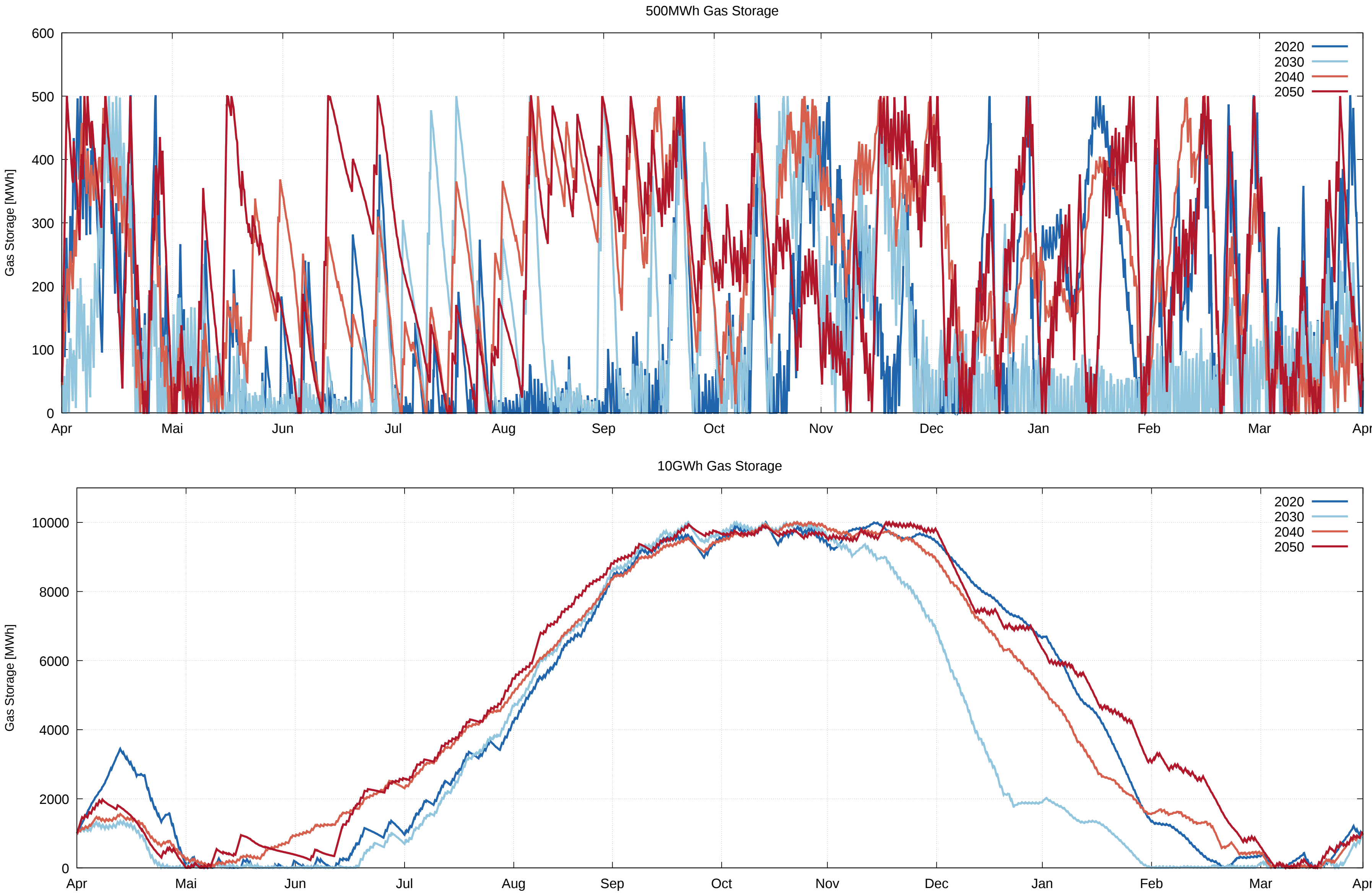

Figure 4.11.9: Annual hourly utilization of the H2 storage.

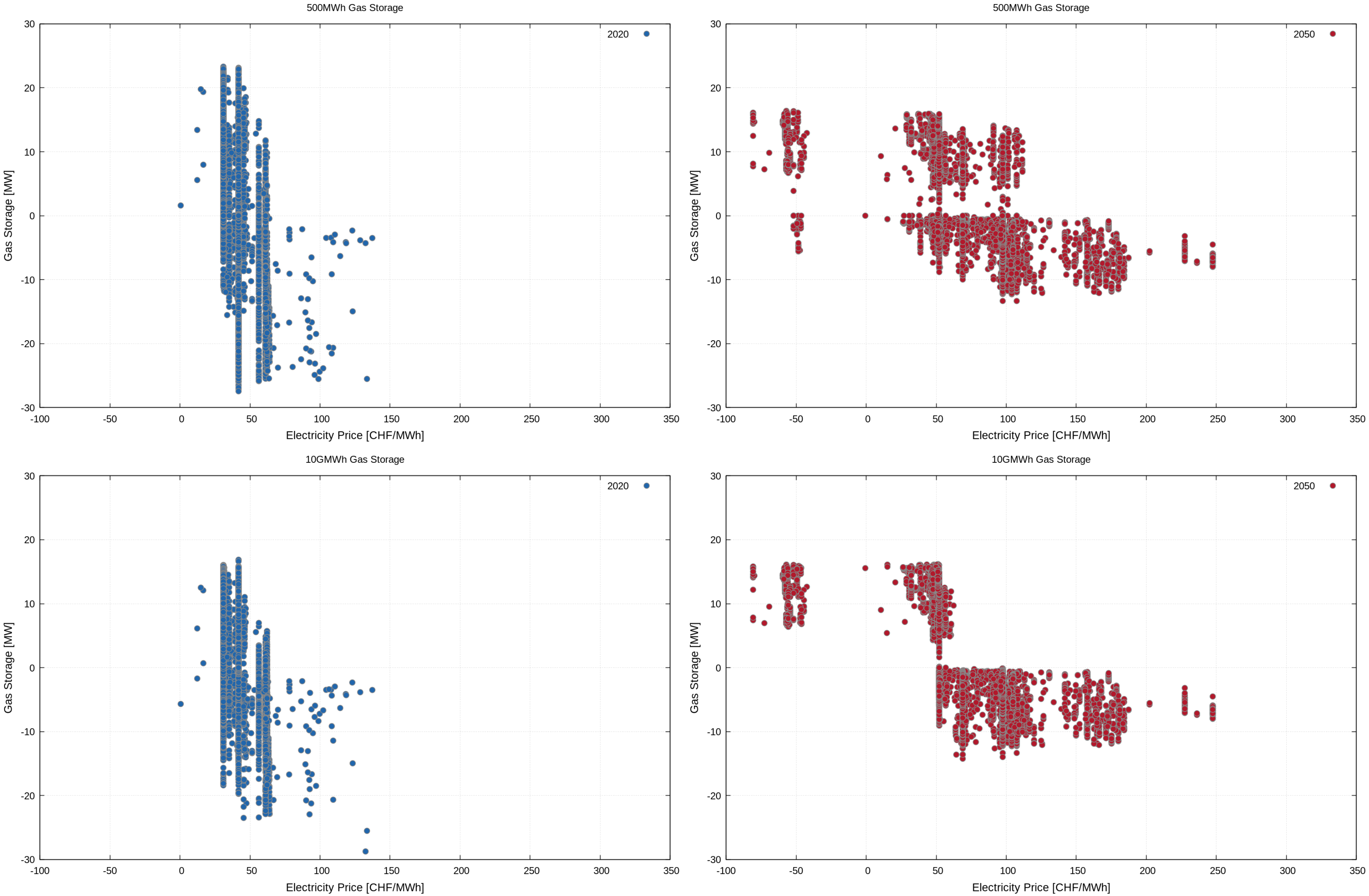

Figure 4.11.10: H2 hourly stored quantity (positive) or quantity injected to the gas network (negative) vs. hourly electricity price.

4.12 Electricity network upgrades driven by PV penetration

As it has been already discussed in the previous sections, the electricity distribution networks utilized in this study are capable of accommodating every potential future demand pathway, including the ones with the highest degree of electrification of end demand (such as the "Electric+", "No-Gas" or "Circulago" demand scenarios). In this section, we complement the study by analyzing the extend at which scenarios with high PV penetration motivate investments in electricity network upgrades, alone or combined with enabling technologies (batteries, electrolyzers, fuel cells).

Since, as shown in Section 4.1, the Herti electricity network can to a very large extend accommodate even the most aggressive PV penetration scenarios (see Tables 4.1.1, 4.1.2 and 4.1.3), in this section we will present results utilizing the Altgass electricity network of the WWZ system. Similarly to Herti, Altgass network is also able to accommodate even the most aggressive electrification of demand considered in this study. However, as shown in Table 4.12.1, the PV potential of this district (which is outside the city center) is high enough to create potential motivation for network upgrades.

The last column in this table results from the multiplication, per hour, of the amount of PV energy which is curtailed due to congestion with the electricity price during that hour. As discussed in Section 4.1, this value indicates the amount of additional benefit that can be made if the corresponding congestions are alleviated. One can also observe that, especially in the case of the "High Std" electricity price scenario, a non-negligible value potential for energy storage exists, i.e. to shift V energy from moments when it is a stress to the wholesale level (hence the negative price) to moments when it is valuable. Clearly, network upgrades cannot help in extracting this potential value lost. This value is difficult to quantify, as it depends on the price difference between the hour of charging and the hour of discharging. However, it is worth noting that most of the PV curtailment takes place during hours with negative prices, i.e. it is not driven by network congestion. Still, contrary to the Herti network, the value of the PV power which is curtailed due to network congestion is not negligible.

Table 4.12.1: Altgass: Total PV curtailment (MWh) in 2050, without new investments

Elec. Price scenario	**PV scenario**	**Demand scenario**	**PV curtailment due to neg. price**	**PV curtailment due to congestion**	**Value of curtailed PV due to cong. (CHF)**
Reference	High	Electric+	2'383	542	160'034
Reference	High	Reference	3'099	542	209'272
Reference	Reference	Electric+	1'176	482	78'280
Reference	Reference	Reference	1'716	482	114'962
High Std	High	Electric+	7'556	128	6'968
High Std	High	Reference	7'556	373	21'038
High Std	Reference	Electric+	6'717	2	100
High Std	Reference	Reference	6'717	37	1'918

Figures 4.12.1, 4.12.2 and 4.12.3 present results of the optimization problem for a selection of scenario combinations. The considered PV scenarios are limited to the "High" and "Reference" which are the ones stressing the electricity network.

Figures 4.12.1 and 4.12.2 differ from each other in the selection of the electricity price scenario. The "Reference" scenario is used in Figure 4.12.1 while the "High Std" is used in Figure 4.12.2. The electrolyser and battery costs are fixed to the values of the "AEC-Ref" and "Bat-Low" scenarios. It can be observed that, in both cases, branches are being upgraded. This is driven by the value of PV production that can be, as a result, utilized instead of being curtailed due to congestion.

In the case of Figure 4.12.1, no battery capacity is built. As already shown in Section 4.8, the "Reference" electricity price scenario does not motivate investment in batteries to perform energy price arbitrage. In what concerns congestion alleviation, grid expansion turns out to be a more economic solution. On the other hand, in the case of Figure 4.12.2, an investment to a non-negligible amount of battery capacity is proposed by the optimizer. As expected from Section 4.8, this is primarily driven by the electricity price variability (as here the "High Std" price scenario is used). In other words, the battery is mainly built in order to perform price arbitrage, not to alleviate local congestion. It appears that, as a consequence of the battery presence, somewhat less network expansion is required. The observation made in Section 4.8 is validated also in the case presented in Figure 4.12.2; a battery storage duration equal to 5-6 hours seems to be the optimal choice.

It can also be observed (as expected based on Tables 4.1.2, 4.1.3 and 4.12.1) that the scenarios where the available PV is relatively higher compared to the electricity demand provide a greater motivation for grid upgrades.

In the case presented in Figure 4.12.3, which corresponds to a battery CAPEX evolution according to the "Bat-Med" scenario, no batteries are installed. The battery is too expensive, despite the, again, high electricity price variability. As a result, more network expansion is made, similarly to the case presented in Figure 4.12.1.

In all cases, the proposed investment in electrolyzer capacity follows the dynamics identified in Section 4.7 and has no connection to the management of the network congestion. As a matter of fact, congestion could in principle be managed by means of combining electrolyzer (which is anyway installed for its own price/cost relations) with fuel cell capacity. However, this option was never selected by the optimizer, due to its overall cost (CAPEX and reduced overall efficiency).

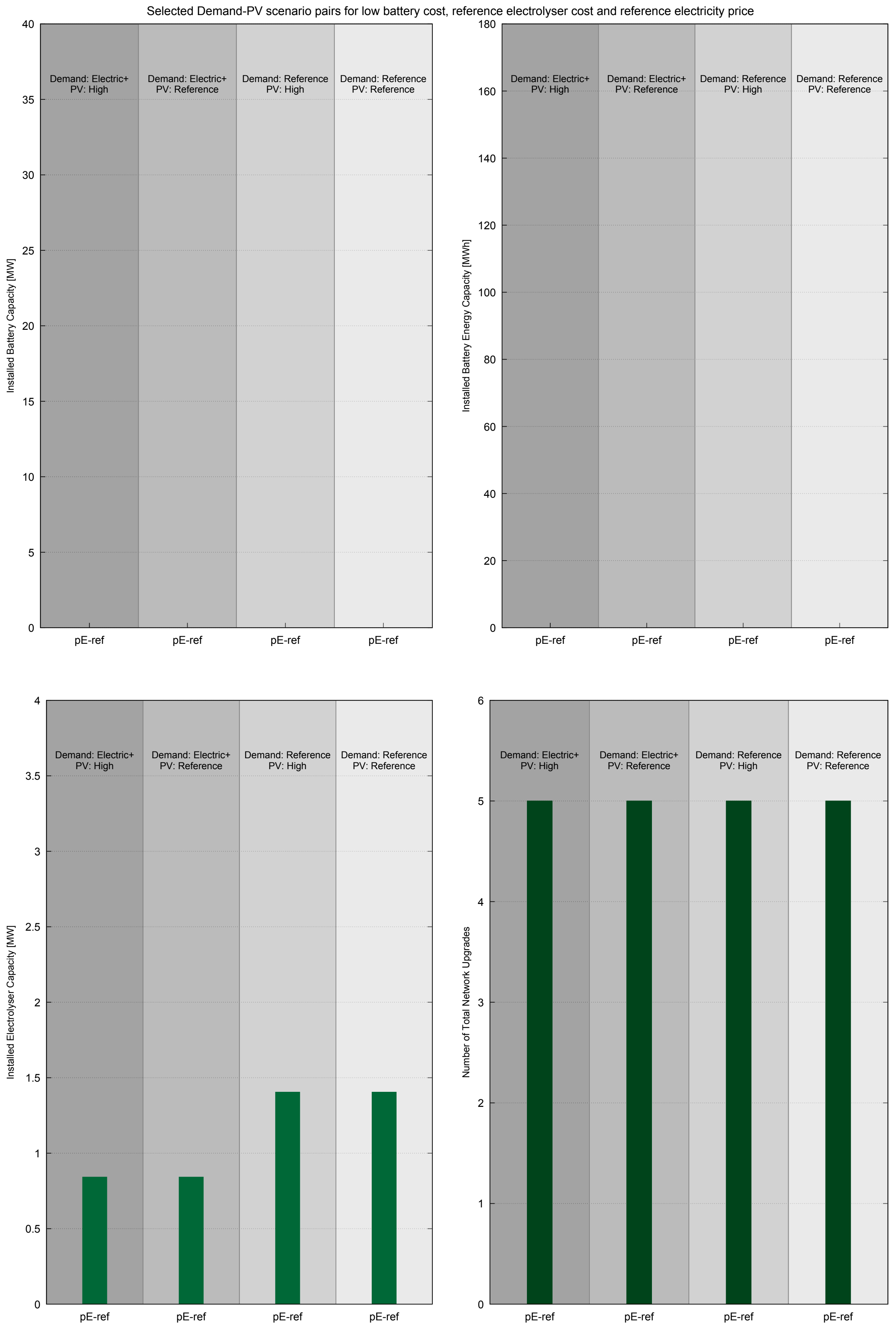

Figure 4.12.1: Optimal network upgrades, new electrolyser capacity and new battery capacity for four combinations of the Demand and PV scenarios. The analysis is performed for the "Bat-Low" battery, "AEC-Ref" electrolyzer, "Reference" CO2 tax and "Reference" electricity price scenarios. Absence of a bar denotes that the value is zero.

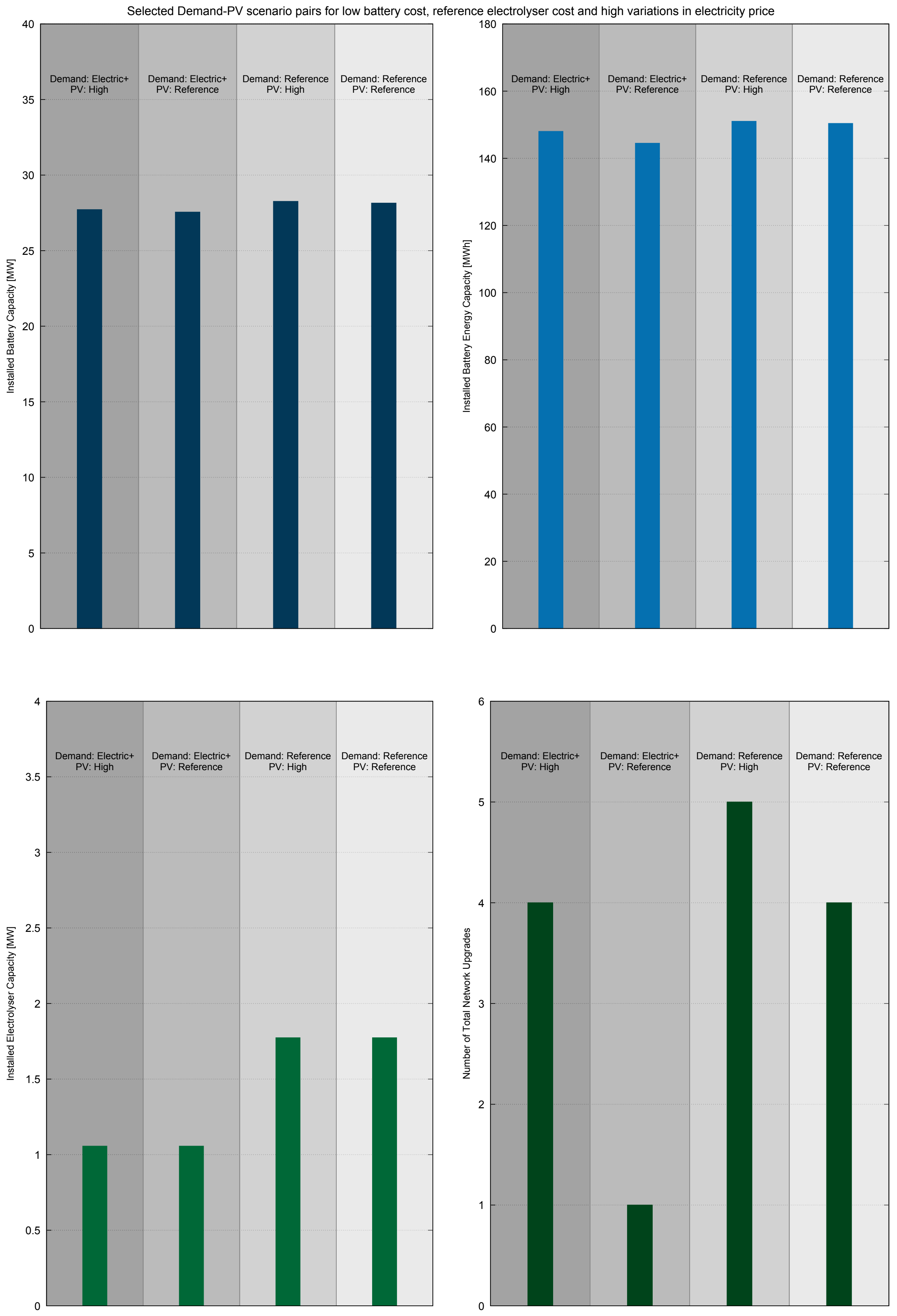

Figure 4.12.2: Optimal network upgrades, new electrolyser capacity and new battery capacity for four combinations of the Demand and PV scenarios. The analysis is performed for the "Bat-Low" battery, "AEC-Ref" electrolyzer, "Reference" CO2 tax and "High Std" electricity price scenarios.

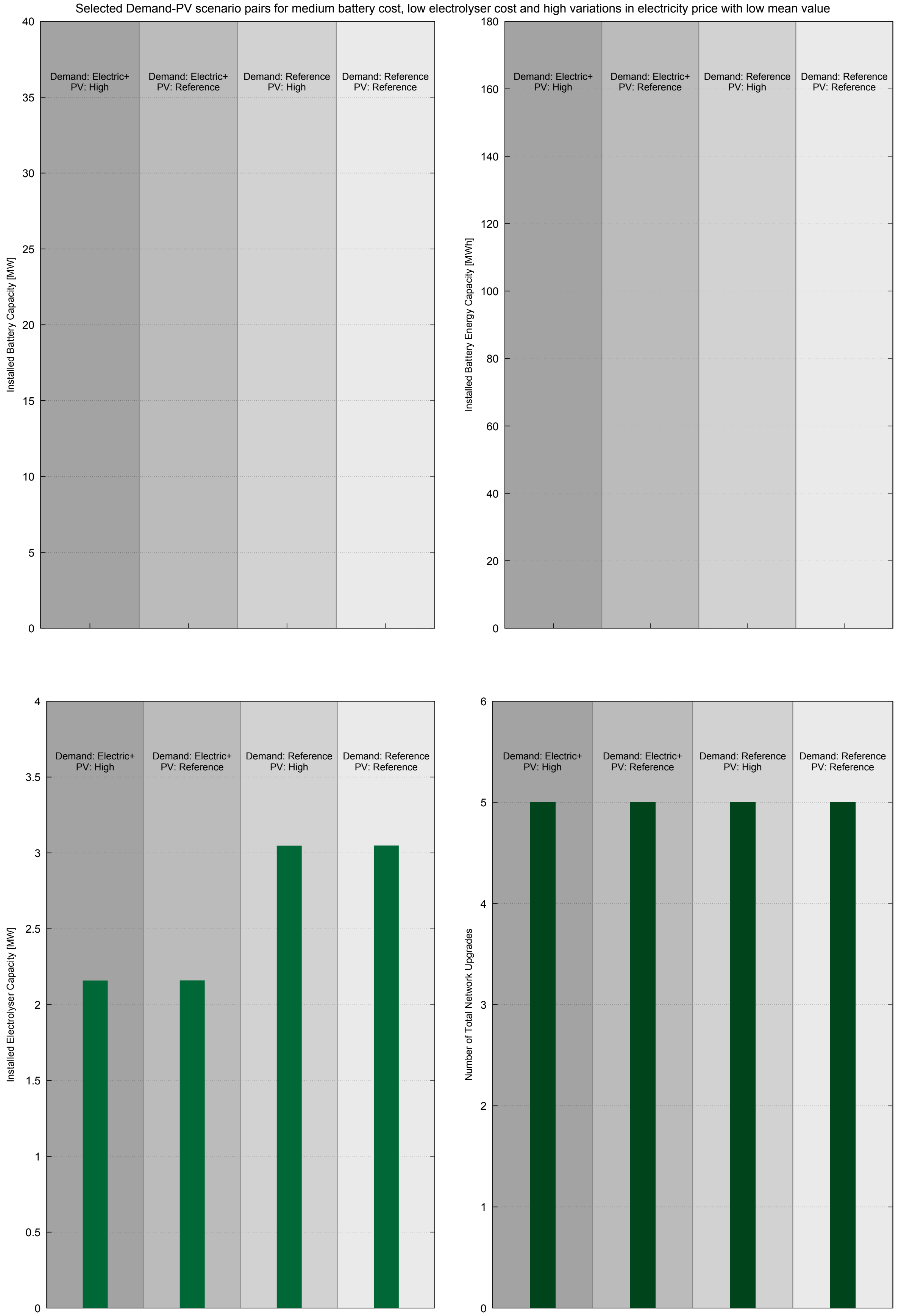

Figure 4.12.3: Optimal network upgrades, new electrolyser capacity and new battery capacity for four combinations of the Demand and PV scenarios. The analysis is performed for the "Bat-Med" battery, "AEC-Low" electrolyzer, "Reference" CO2 tax and "Low Mean - High Std" electricity price scenarios. Absence of a bar denotes that the value is zero.

5 Project conclusions

This section summarizes all the findings of this study. The conclusions presented in the sequel are based on the results that have been presented in detail in Section 4 of this report. The findings below are subject to the limitations of this study, presented in Section 2.2.

1. The cost differences between a pathway of full electrification at distribution level (dominated by building-level heat pumps) and a pathway in which gas maintains a considerable role in serving the end demand for heating is relatively low (below 5%, i.e. up to 50 million CHF of total cost over a 40-year time horizon) or even zero.

    - Which pathway is more economic, on the long-term, strongly depends on the future final costs and thus prices of gas (natural gas, but also alternative gases, such as power-to-gas or biogas) and electricity.
    - Since these prices are typically correlated with each other[19], it is likely that in the future they will not deviate enough from each other to invalidate the observations of this study.
    - It is important to emphasize that the total cost differences appear in the long-term horizon. As a result, choices made today are subject to the uncertainty of the future evolution of influential parameters (electricity and gas prices as well as the CO2 tax).
    - The developed analysis framework can accommodate the case where the "gas" is a renewable gas, such as biomethane or synthetic methane. Similar conclusions can be made for given assumptions of the price at which such a gas can be purchased by the utility. However, an identification of potential future wholesale prices of synthetic methane (or biomethane) was not part of this project, hence no conclusions are drawn on this topic, which is arguably very relevant in the context of a CO2 net-zero strategy.
    - Let us recall here that a pathway which is extensively relying on building-level air-sourced heat pumps might not be practically feasible (especially in urban regions) due to noise regulations or space limitations (see Sections 2.2 and 6).

2. In districts or regions where a convenient source of environmental heat is available (such as the Lake of Zug in this study), investing into a heat-pump-based district heating system seems to be the most economic option in the long-term.

    - The cost will probably be region-specific. In our analysis, based on the cost of Circulago project, heat-pump-based district heating was found to lead to ~2-4% lower total cost compared to equivalent scenarios relying on air-sourced heat pumps and gas boilers.
    - Significant upfront investments are required. The advantage is that these investments need to be undertaken by the utility, not individual customers, which might make them somewhat easier to be decided and funded.

3. A pathway of full electrification (of customer space heating) is economically feasible.

    - This pathway requires more expensive upfront investments by customers (to invest in local heat pumps) or utilities (to build district heating systems).
    - These investments will be paid off in the long-term thanks to the higher efficiency of heat pumps (which enables lower operating energy costs) compared to gas boilers (or fuel cells).

[19] Due to the fact that one is produced by the either, but also due to overall market phenomena.

4. Policy decisions are required in order to prioritize a specific desired evolution.
   - In the absence of (policy or other) interventions that would make one pathway preferable than the other by a large margin (measured in terms of cost to meet the demand for energy), it is reasonable to assume that both will develop to some extend in different regions.
   - A pathway which relies on natural gas cannot be CO2-free[20]. Hence, from the energy and climate policy perspective, it might be undesirable. However, the results of this study show that, solely based on economic criteria, customers might not switch to heat-pump-based heating in the pace required in order to meet net-zero CO2 emissions by 2050 target set by the Swiss Federal Council.
5. The MV electricity distribution networks considered in this study turned out to be capable of coping with an increased electrification path. Network upgrades can still be required in order to maintain a high degree of redundancy and, hence, reliability.
   - One assumption that motivated this study was that the electricity distribution networks might not be able to cope with an increase of the electricity demand. This assumption is not confirmed by this study.
   - First, the electricity networks utilized in this study were able to accommodate larger amounts of power flows. In other words, the today's networks are oversized with respect to today's electricity demand, hence they can accommodate an increase in demand.
   - Second, even if the utilities need to make investments in network upgrades (either because they are really needed, or in order to maintain a high degree of network reliability), their cost is clearly not prohibiting. They do not make the electrification pathway uneconomic.
   - Finally, let us recall that potential congestions stemming from the LV networks were not considered in this study.
6. In case of congestion, upgrading the electricity network infrastructure is more economic than resorting into alternative options such as batteries or sector coupling[21], which might have a role only if electricity network upgrade is impossible for other practical (not strictly economic) reasons.
7. The role of gas distribution network infrastructure is dependent on the followed pathway. Obviously, it is required for a pathway in which there is demand for gas at the distribution level. On the other hand, it is not required as an enabler of an electrification pathway.
   - One assumption that motivated this study was that the gas network can act as a parallel energy delivery path which would facilitate alleviating electricity network congestions resulting of an electrification pathway. As explained in the item above, this assumption is not confirmed by this study.
   - As a matter of fact, the conversion cycle from electricity to hydrogen and back to electricity in distribution level turned out to be too expensive and inefficient to have a role in the scenarios considered in this study.
8. Hydrogen production seems to naturally couple the operation of the electricity and gas systems.
   - Boundary conditions were identified in which electrolyzers have value, stemming from allowing to meet part of the gas demand by consuming electricity (and converting it to H2 which is then injected into the gas network) at moments when the electricity price is low enough compared to the cost of gas (i.e. gas price and CO2 tax).

[20] On the contrary, it emits more CO2 than an electrification pathway, as shown in Section 4.2.2.

[21] Let us recall that PV curtailment was considered to be an acceptable option in this study. Nevertheless, as illustrated in Section 4.12, network expansion is often worth it, in order to allow more PV energy to be utilized at moments when electricity prices are high enough.

- Drivers for investments in electrolyzer capacity are: increased demand for gas, higher cost of gas, lower and/or more variable electricity prices.
- Intermittent operation of electrolyzers might be required in the future, as their economics (at least, at the distribution level) are driven from the instantaneous price difference between electricity and gas.

9. Hydrogen storage enables more efficient utilization of electrolyzers, as it allows them to operate when electricity is cheap, irrespective on whether there is demand for H2 during these moments.
   - The benefit of H2 storage is somewhat higher when the variability of electricity price is higher.
   - In the related analysis performed in this study, H2 storage was utilized in the relatively short-term horizon, while it turned out to be less valuable as a seasonal storage. However, this is strongly driven by the utilized wholesale electricity price time-series. A transmission/wholesale-level analysis is required, in order to identify the actual systemic value of H2 storage in a future energy system.
10. Batteries are expensive and, hence, not offering value. If their cost drops enough, then their value increases, especially in scenarios with high electricity price variability.
    - The sensitivity analysis showed that a battery becomes cost-effective if its CAPEX drops to ~150 CHF/kWh.
    - Electricity network upgrade is more economic than batteries in alleviating congestion[22]. The latter could be used, however, in cases when network upgrade is not desirable or acceptable.
    - At distribution level, it is still cheaper to invest in batteries than performing sector coupling investments as means to alleviate congestions in the electricity network, for congestions lasting up to a few hours.
    - In scenarios when batteries are "cheap enough", their value stems from performing electricity price arbitrage, i.e. their value comes from the greater transmission/wholesale-level dynamics, rather than needs in distribution.[23]
11. Evolutions at the transmission/wholesale level are the key in studying the overall economics of the energy transition.
    - All the findings of this study are dependent on the assumptions made about the prices at which electricity and gas will be available to a utility. These assumptions, made in this study, implicitly corresponded to a certain correlation (or lack of correlation) among these prices and a certain quantification of the value of flexibility.
    - The approach was top-down (hence unidirectional), in the sense that the distribution-level scenarios (i.e. the demand and PV penetration scenarios) made in this study were not reflected on the wholesale-level assumptions (i.e. the electricity and gas prices)), i.e. no feedback from local demand and production to the wholesale production was assumed.
    - It is of paramount importance to be able to properly model the expected future evolution of electricity prices, in scenarios were the traditional power generation mix (and hence the dynamics which result in the electricity prices) is considerably changing.
    - This study illustrated the dependence of the results on not only the mean value but also the variability of the wholesale electricity prices (e.g. value of batteries in case of high variability).

[22] Let us recall that PV curtailment was considered to be an acceptable option in this study. Nevertheless, as illustrated in Section 4.12, network expansion is often worth it, in order to allow more PV energy to be utilized at moments when electricity prices are high enough.

[23] Clearly, this observation holds within the modeling assumptions and boundary conditions of this project, where the emphasis has been on hourly resolution modeling of the active power.

6 Suggestions for further research

As explained in Section 2.2, this study focuses on the quantification of final energy demand by energy carriers and the associated technologies and costs at the levels of end-customer and of energy distribution. The availability of those energy carriers at the transmission/wholesale level and the cost at which they can be offered to a distribution utility have been treated as a boundary condition of this study. Reference values, taken from other studies, were used, while sensitivity analysis was performed around these reference values.

It was shown in this and in other studies that the results and conclusions regarding the selection of heat energy technology are strongly dependent on:

- the assumptions made regarding the wholesale price of the energy carriers, and
- the costs at which low-carbon end use energy systems might be deployed to buildings and firms.

We propose that further research is undertaken to tackle this aspects, as follows.

It is important to note that typically the wholesale prices of electricity and gas are strongly correlated in the international market system as the price setting kWh of electricity is usually generated by a fossil-based power system (gas or flexible coal). This holds true today and is expected to remain the case in the future when gas-(or sometimes coal-) powered electricity is expected to be the remaining technology to balance intermittent power generation from renewable sources. Also for Switzerland, the marginal cost of gas-based power generation is price setting, although gas-fired power plants are not part of the electricity generation mix. The international power exchange is the driver for such market coupling. Even if, in the future, the role of natural gas decreases and new gases (such as hydrogen and synthetic methane) take over an important role in the energy system, it is again expected that a correlation relationship between gas and electricity will be maintained, since these gases are essentially produced by consuming electricity.

For the above reasons, a study which identifies the optimal evolution of the future energy system at transmission / bulk energy level will make up a valuable complement to the tools developed and the analysis performed in this project (i.e., the "Role of Gas" project). Such a study shall be able to model the correlations between different energy carriers and account for the potential benefits of their coupled planning and operation, accounting for moments of scarcity of renewable energy sources. In addition, the CO2 emissions corresponding to the electricity generation mix will be an internal variable of such a study, while the analysis can also consider the production of "renewable" gases, such as hydrogen and/or synthetic methane, hence accommodating a future CO2 net-zero energy system. Finally, such a study will allow to identify whether it might be beneficial, from the overall system perspective, that different regions follow somewhat different (hence complementary) pathways instead of all "synchronizing" to one common "optimal" pathway. This might reduce the needs for flexibility at transmission/wholesale level, hence allowing each region to have predictable access to the energy carriers that it needs.

These differences in regional development are mainly driven by the availability of renewable energy sources for heating and electric appliances. Especially in the case of renewable heating, the local or site-specific potentials might be limited. As shown in this study, the availability of ground source ambient heat is limited due to large groundwater protection zones correlating with zones of high heating demands (e.g., in the areas of the city of Zug and Baar). More detailed analyses on the effective potentials can also help to better differentiate between ground source (i.e., geothermal) and ground water-based environmental heat (see also [22] for more details).

Additionally, in this study the potential limitations for the use of air source heat pumps were not considered based on e.g., noise restrictions or potential limitations of unit sizes for heat pumps compared to the heat energy demand per building site. From studies such as [22] and [23] one can see that especially in densely populated areas with high heating demand, air-source and other decentralized heat pumps might not be feasible to supply sufficient heat energy. Therefore, other grid-connected (or solid/liquid) energy carriers need to be in place to provide the necessary level of energy in such areas.

Focusing on such grid-connected energy carriers, the research can be further improved by including different heat distribution cost steps. Depending on the specific region and available heat sources, the distribution costs for district heating vary. In urban areas with existing infrastructure of various types in the ground, adding additional tubing and pipelines is likely to be more costly compared to areas which are newly developed or less densely developed. The study at hand is considering the specific heat distribution costs experienced in the region of Zug but they can largely vary across different regions. This also applies for the investment costs for other heating systems: different cost levels can be defined for identical heating systems as these investment costs are highly project specific. As a matter of fact, such cost steps might be comprehended as a stylized cost-potential-curve if they are considered as a function of increasing the share of the exploitation of the potentials (this approach is currently implemented in the SFOE research project LICS [8]). Adding more cost steps (in the sense of a linearized cost-potential curve) to the optimization model for different heating technologies to represent different levels of project specificities and complexities would allow to better understand the interactions between more costly individual heating solutions compared to grid connected systems connecting several buildings and heating sites.

Hence, we suggest expanding future research in both scaled and topological directions:

- the macro (transmission grid and wholesale energy conversion), and
- the micro/spatial level (assessing buildings and firms in their local context).

By expanding the research into these fields, one can gain better insights into the relevant results on sector coupling of different energy carriers in specific locations and under different boundary conditions.

Additionally, combining the aforementioned "transmission-level" study with the "distribution-level" study presented in this report will allow for a complete quantification of future energy transition pathways.

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Appendix

7 Determination of energy demand and renewable potential

The final energy demand for electricity and heat of the various residential and commercial buildings, as well as the renewable energy potential of the considered region were computed as part of this project.

7.1 Methodology

The Building Stock Model (BSM) was used to calculate the demand in high temporal (hourly, per year) and spatial resolution (per building). The BSM is a bottom-up simulation model which is used to project energy demand of and in buildings for different scenarios based on an internal decision model. In the following, the general model approach, the regional coverage, the model calibration and relevant scenario assumptions are described in more detail.

7.1.1 General approach

A large part of the building-related quantitative questions is answered with the bottom-up and geo-referenced building stock model (BSM) [24] which is a further development of the Swiss BSM of TEP Energy [25]. This concerns in particular the scenario-related calculation on the number of buildings and heating systems affected by the specific scenario drivers, the growth rates and market share developments of heating systems and the associated investment and annual costs (aggregated and with the same database also at the level of the individual buildings and heating systems) as well as the effects on final energy demand and CO_2 emissions.

The system boundaries of the model calculations and the influencing factors considered are described in the following (and visualized in Figure 7.1.1).

The annual final energy consumption per energy carrier (electricity and heat) results from the sum product of various drivers (summands), which are differentiated according to various characteristics:

*Final energy demand per energy carrier = Sum over all buildings of {quantity structure * specific heating and specific electricity demand * energy carrier (market) share / (heating) system conversion efficiency}*

In this project a building specific version of the BSM as described in [24] was used Space heating demand is calculated based on fundamental building data using the method SIA 380/1. As such various energy-relevant building attributes geometry, thermal transmittance, air exchange rate, internal and external heat loads can be considered. Some of these attributes depend on earlier building energy codes and past retrofit activities. Specific heat demand calculated as such is also the starting point to specify both design heating system capacity (relevant to calculate investment costs) and system full load hours.

Thus specific heat and electricity requirements, i.e. the heat requirement per m^2 and the electricity demand per energy service, essentially depends on the type of building, the construction period, the building use and the energy retrofit state. Additionally, the quantity structure, i.e. the heated floor area, is also differentiated according to these characteristics (see Table 7.1.1). A distinction is made in the energy market share between new buildings, protected buildings and periodic renewals. For historical reasons, this also results in a different distribution in the starting year of the analysis.

These factors are differentiated according to various characteristics (the most important ones are given

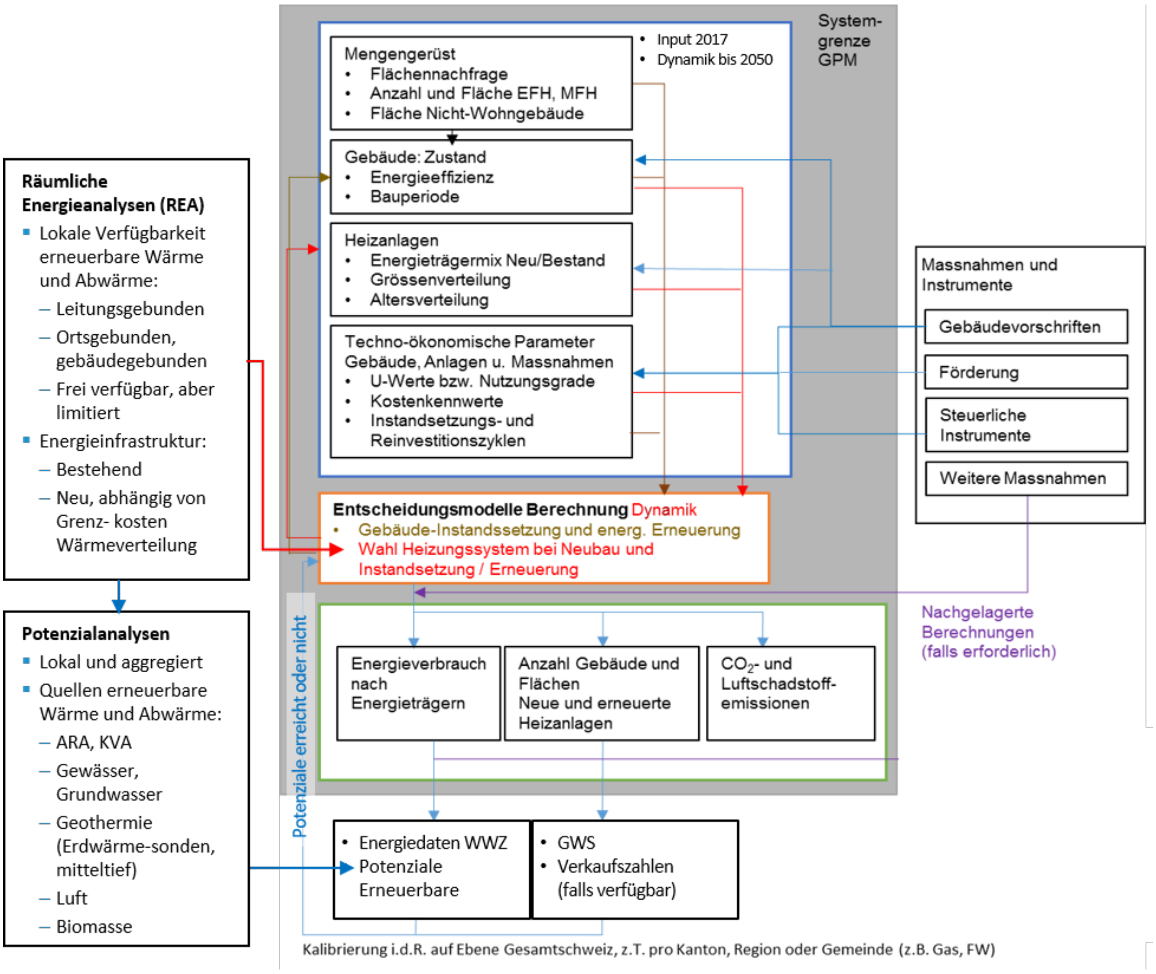

Figure 7.1.1: Overview of the building stock model and the project relevant interfaces und data sources. Source: TEP Energy

above) and are subject to changes over time, which are considered in simplified terms in the model as follows:

- Quantity structure: Disposal by demolition, replacement new building, extension by new buildings and heating systems.
- Specific heat demand: Heat demand of heating Q_H and of hot water Q_{ww} in accordance with SIA 380/1 (2009), depending on construction period and state of energy retrofit, influenced by renovation activity (repair vs. reinstatement vs. energy retrofit) depending on repair cycles and energy prices (based on a micro-economic decision model, see explanation below).
- Energy source market shares: The market shares in new buildings and of heating system renewals (depending on maintenance cycles and time of last renewal) results from an aggregation of choice probabilities which depend on techno-economic plant parameters (investment, maintenance, energy costs) and energy prices. The future market shares are also dependent on the energy source availability (and restrictions) at the building's location and on energy source potentials depending on zoning plans or other spatial entities. These factors depend on the type of renewable energy source and on energy infrastructure availability or expansion.
- Heating system conversion efficiency: Depending on the time of installation and the energy efficiency of the building (heating distribution supply temperature).

In the building stock model, the choice of heating systems and energy sources as well as the decisions to implement efficiency measures are represented by an economic decision model in which the energy-related investment and operating costs of available options are considered. In addition to the operating costs which are influenced by energy prices and taxes, the investment and capital costs also change over time, due to the assumed techno-economic progress (as laid out in [26], [27] and [28] and for the past). This also influences the development of technical parameters of the measures and systems under consideration (e.g. the thermal properties of thermal insulation and windows as well as the efficiency of heating systems and electrical appliances).

Factor	Characteristics and differentiation features
Quantity structure	Reference energy floor area (REFA, in German: EBF) per building type, building period and building (elements) retrofit status
Specific heat demand	Useful energy demand per building type, construction period and building (elements) retrofit status
Specific electricity demand	Useful energy demand per use type, appliance and efficiency standard
Market shares of heating systems / energy carriers	Proportions of different types of heating systems or energy sources in new buildings and in the case of system renewals (the latter depending on the system already installed)
System conversion and system full load hours	Utilization level per system age class or year of installation, resp. and level of energy efficiency of building and appliances

Table 7.1.1: Overview of the factors to calculate final energy demand and the resp. criteria considered in the definition of the factors. *Quelle: TEP Energy.*

For the present project, the BSM was adjusted in such a way that region-specific statements on the development of the final energy demand and the choice of energy sources and heating systems can be made (see the following section on the spatial coverage).

In addition to the spatial adjustments, the BSM was extended in such way, that hourly load profiles for electricity and heat can be generated. The methodology to expand the annual demand calculations to hourly values is similar as the one adopted in the modelling system FORECAST-eLOAD (see www.forecast-model.eu for details):

- Specific hourly load profiles of the most relevant end uses are linked to the respective annual energy demand of each of these end uses. Moreover building-related energy production (such as PV) and storage options are added to the model.
- Depending on the current situation and on each buildings' boundary conditions (e.g. availability and restrictions of renewable energy sources and grid infrastructure), the investment decisions (e.g. choice of the heating system) is modelled based on micro-economic principles (based on the utility function approach).

7.1.2 Spatial coverage

The model describes in detail the building stock of selected villages of the canton of Zug, based on the sales area for electricity and gas/heat of the project partner WWZ. Therefore, the five municipalities Cham, Zug, Baar, Hünenberg and Risch are considered in this study. However, as the sales and grid areas are not fully congruent for the different energy carriers, the following situation applies:

- The electricity grid comprises the communities Zug, Cham, Baar and Risch
- The gas grid comprises the supplied communities Zug, Cham, Baar, Hünenberg and Risch
- The district heating network in Zug is considered (e.g. Altstadt and Circulago)

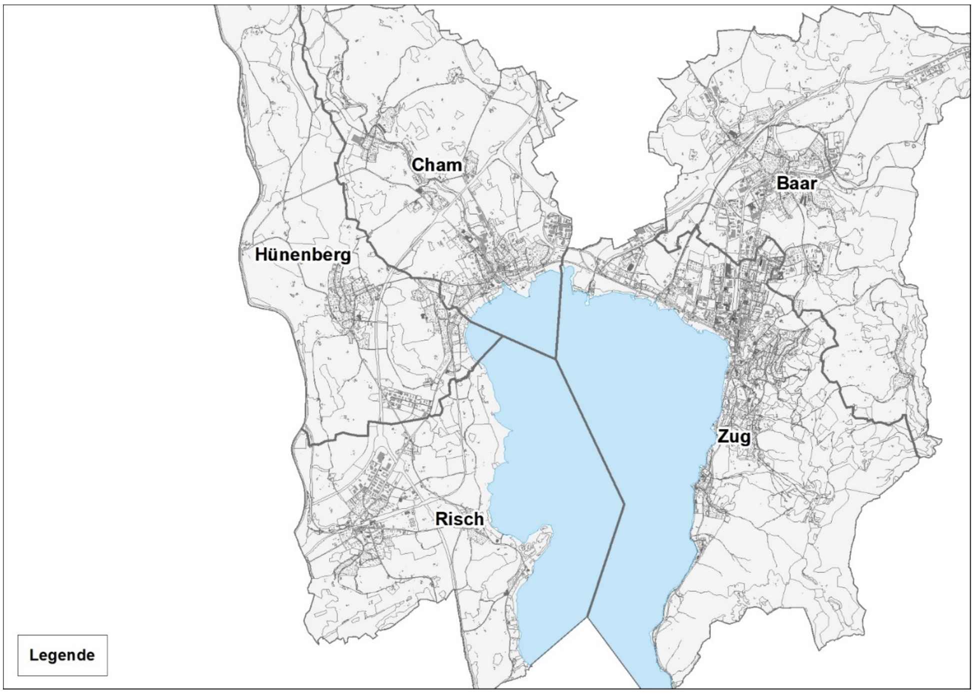

Figure 7.1.2: Overview of the municipalities considered in the study. Source: TEP Energy

A map of the considered areas is shown in Figure 7.1.2, already including information on the availability of potential heat sources. More information on the definition of the specific heat source zones is given in the following section.

7.1.3 Data sources and model calibration

As introduced, different data sources are integrated in the BSM to accurately describe the building stock of the considered communities. The aim is to define for each building its age, the currently installed heating system, as well as the reference energy floor area and the building use, amongst others. For each building, also the availability of renewable energy sources (such as solar power or heat, ambient heat, etc.) is identified. This is based on the different data sources this can be achieved by partially linking data sources via graphical information systems (GIS) and a data update and imputation via statistical distribution functions otherwise (see Table 7.1.2 for an overview of all data sets included).

Nb.	Data set description	Data provider	Linked data on building level
1	Building and dwelling registry (GWR)	FOS	Yes
2	3D building shapes	swisstopo	Yes
3	Zoning plans (construction reserve, protected buildings, groundwater protection)	Ct. Zug	Yes
4	Solar cadastre	SFOE	Yes
5	Annual electricity and gas demand per node	WWZ	Yes
6	Companies and enterprise registry (STATENT)	FOS	No
7	Heating systems and sizes above 75kW	Combustion system control, Ct. Zug	Yes

Table 7.1.2: External data sources as input to the building stock model, defining the building stock and potentials for different heat and energy sources in the area of investigation.

Currently, the most accurate overview of the entire building stock is defined by the buildings and dwellings registry (GWR), provided by the Federal Office of Statistics (FOS). This data set classifies buildings according to their building coordinates, their use (different categories and classes of residential and services sector buildings) and building age (year of construction) and information on heating systems. In the case of Zug, the registry is only complete in terms of residential buildings and therefore goes into the BSM for this building type.

As the data on service sector buildings in the GWR is incomplete on buildings level for the Canton of Zug, we have decided for a statistical approach to calculate service sector energy reference areas. This is done by combining coefficients calculated in [25] with a calculation of floor area per building derived from the 3D building shapes (source: swisstopo).

The data from the GWR is therefore supplemented by more up to date data from the utility WWZ on the heat energy carrier "gas" and additional information from the combustion control of the canton of Zug (see Figure 7.1.3).

For each building, the potential availability of alternative heating sources and grid connections is attributed (see Figure 7.1.4) according to the energy and environmental zoning plans, projected grid expansions (e.g. the ongoing construction of an extensive low temperature grid based on the water from the lake of Zug). This attribution is based on a dedicated analysis of various data sources (see Table 7.1.2) using a Geographical Information System (GIS). More details on the methodology can be found in [22]. Special focus is put on zones where only one source is currently available in form of grid connected energy carriers (i.e. gas only or ground source heat pumps only). Additional information is available on the solar potentials (electricity and heat) which are also incorporated in the model on buildings level (see Figure 7.1.5).

Based on the described building stock, the model is then calibrated to the annual energy demand per grid connection point supplied by the utility WWZ. Calibration year is 2017, from that year on, the model calculates the energy demand development until 2050.

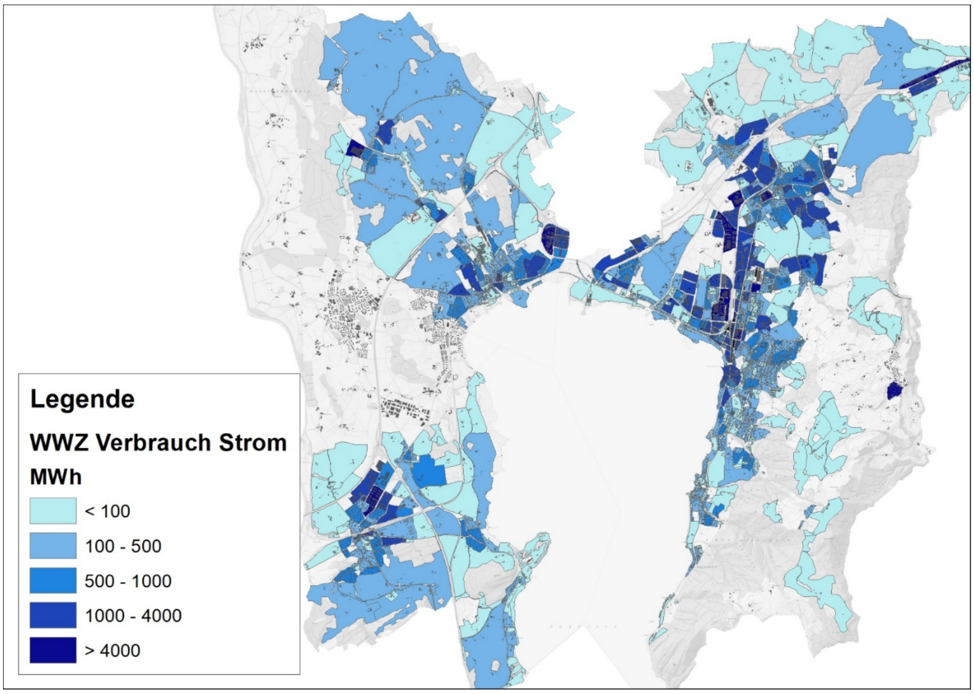

Figure 7.1.3: Building clusters where electricity demand is grouped according to the resp. demand levels.

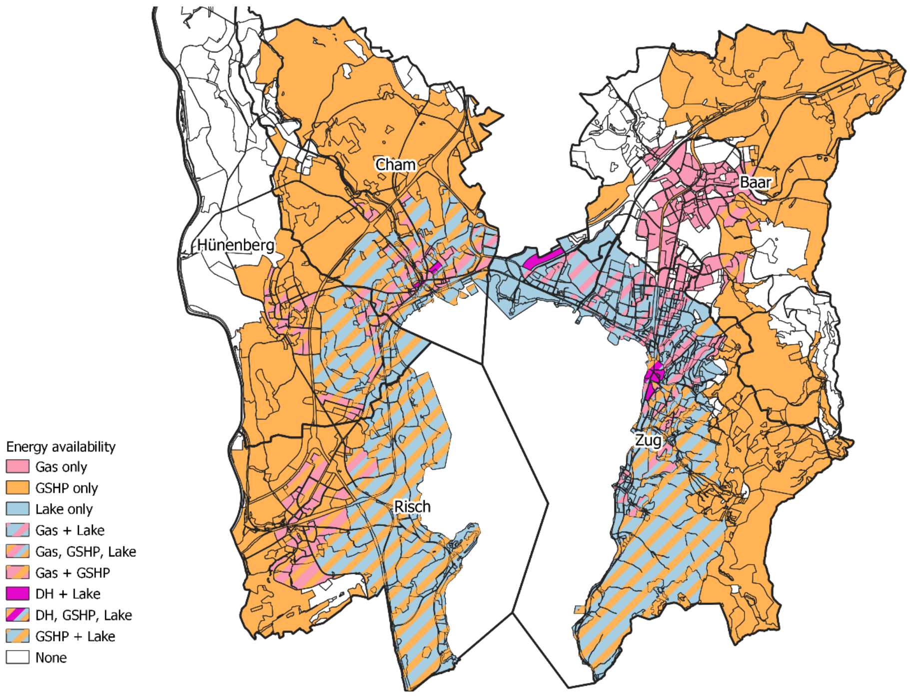

Figure 7.1.4: Overview of the different potential supply zones and energy carrier availability considered in the study. GSHP: Ground source heat pump; DH: District heating. Source: TEP Energy

Figure 7.1.5: Solar cadastre which is available as source for calculating the solar photovoltaics and heat potential.

7.1.4 Scenario data

To calculate the future energy demand, general assumptions on energy carrier price development, different investment cost parameters, GDP- and population growth, as well as building stock developments are needed to properly incorporate such dynamics. Based on the parameters presented in Section 3.1 and the underlying building stock parameters from [25] and the reference area calculations introduced above (Section 7.1.3), the values presented in Table 7.1.3 were considered.

According to the general model approach, the price development of heat energy carriers such as oil, gas and electricity play a crucial role in the development of the scenario results. Based on European wide models such as PRIMES [29] and the output of the REFLEX-project [30] (wholesale market prices), respective consumer price forecasts are derived and considered in the model calculations. In the BSM, therefore, consumer prices are differentiated for residential customers (see Figure 7.1.6) and non-residential customers (see Figure 7.1.7). Incorporated parameters for the price development are grid fees, taxes such as the CO_2-tax which is increasing from 96 CHF/tCO_2 in 2020 to 210 CHF/tCO_2 in 2030 and stable until 2050, as well as the KEV which is considered to remain at 2.3Rp/kWh until 2050.

The different investment and operation cost parameters for heating systems or building envelope depend on various factors such as building age and planned refurbishment measures, the existing heating technology, installed max. capacity, if the system is replaced or completely new, etc. The respective database has been established and updated as part of various projects of TEP Energy [25].

Parameter	Description
Population	Canton Zug: increase of 35'000 inhabitants (+21%) from 2015 to 2050 [31]
GDP	Medium growth 2000-2050: +1.1 % p.a. (national), scaled to Zug [32]
REA	Reference Energy Floor Area (REFA) Increase 2010-2050: +10% per capita [33]
Energy prices	Average annual electricity, biomass and fossil energy carrier prices [29]-[30], (also see Figure 7.1.6), increased CO_2 tax up to 210CHF/t in 2030 and stable until 2050
Policy Environment	Energy strategy 2050, MuKEn 2014 implemented from 2020 onwards, compliance rate of 85%.

Table 7.1.3: Scenario invariant parameters considered for calculating final energy demand until 2050.

To give an overview and general understanding of the model approach on the different costs and cost relations for building related measures, a comparison of two selective building types (single- and multi-family buildings, SFH and MFH, resp.) built between 1986-2000 with specific building parameters (floor size, etc.) is depicted (see Figure 7.1.8). For different fuel types and heating systems, resp., the average capital cost, energy cost and operation and maintenance costs per m^2 of heated floor area is compared. Additional information is provided on the refurbishment cost of building insulation and window replacement.

Depending on the potential availability of such system for every single building (see Figure 7.1.4) and the incorporated capital and energy costs, the specific building parameters (age, floor size, etc.), amongst others, the model simulates the mix of building refurbishment measures and heating system replacements to derive the future building and heating system stock.

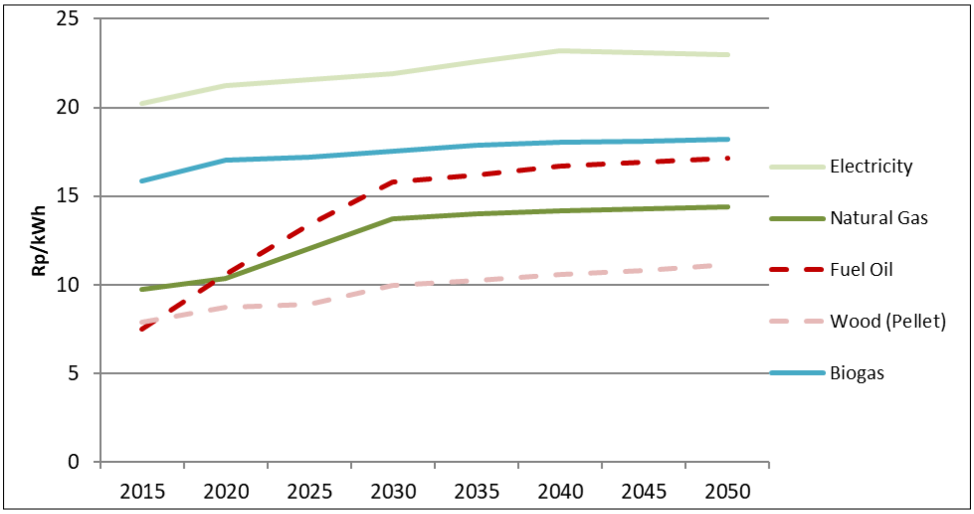

Figure 7.1.6: Consumer prices in Rp/kWh for residential customers considered in the model calculations until 2050 for different energy carriers. Source: TEP Energy

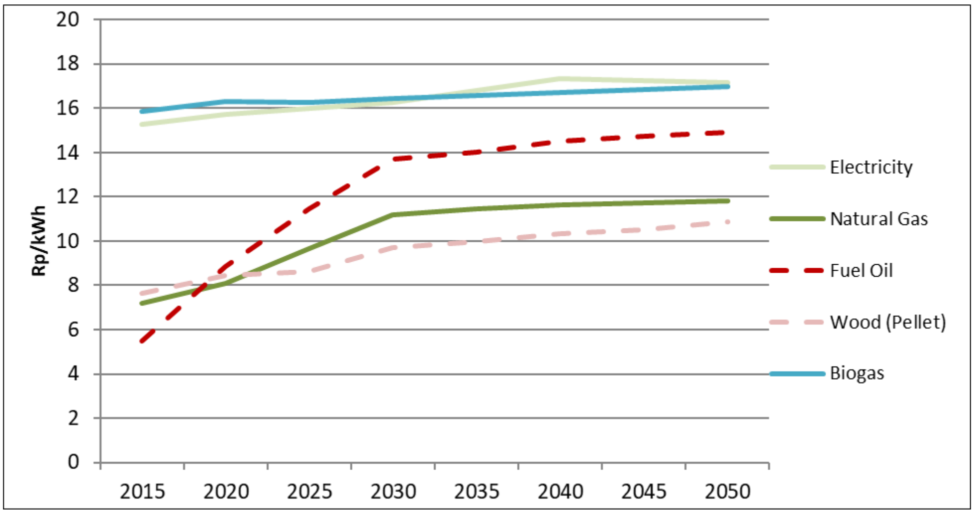

Figure 7.1.7: Consumer prices in Rp/kWh for non-residential customers in the outlook until 2050 for different energy carriers considered in the analysis.

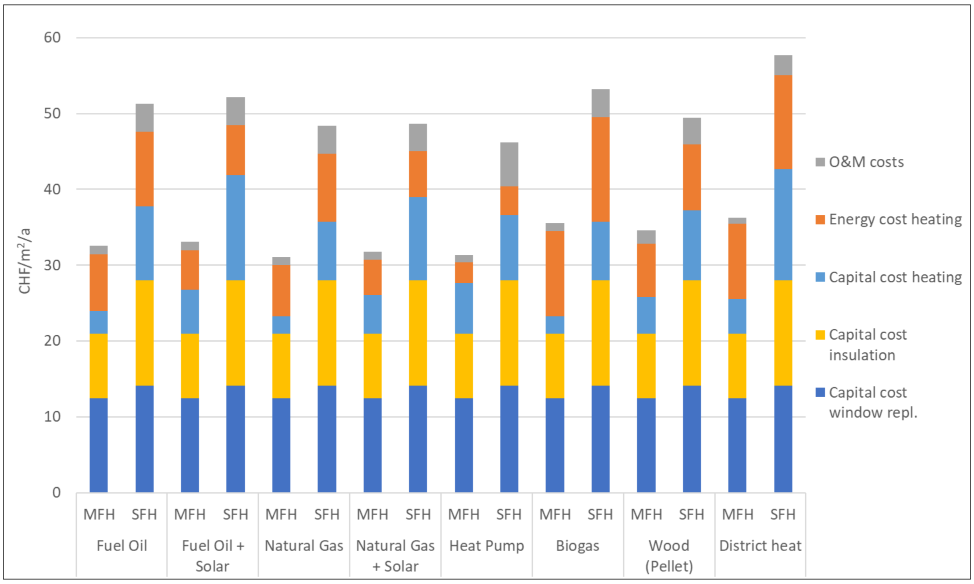

Figure 7.1.8: Comparison of different cost parameters for a set of heating systems available as alternative refurbishment options.

7.2 Results

7.2.1 Energy demand

The energy reference floor area in the study perimeter increases from roughly 5.5 Mio. m^2 in 2015 to 7.7 Mio. m^2 in 2050, a growth of ca. 37% (see Figure 7.2.1). This compares to a projected population growth for the whole Canton of 29% in the same timeframe. Contrary to the scenario specifications in Section 7.1.4, the per capita energy reference floor area can only grow by 7%. Due to the zoning plan, the potential for growth is limited. Many of the parcels in the city of Zug and in Hünenberg municipality are already at maximum capacity today. In order to accommodate future growth and developments in the Canton, growth is taking place in other communities. Growth is largest in Baar, where the available construction reserve is largest. Approximately 60% of the energy reference floor area is in the residential sector.

Until 2050, final energy demand for heating purposes is expected to be reduced by 29%, from 650 GWh in 2015 to 460 GWh in 2050 (see Figure 7.2.2). This is due to various efficiency gains on the level of the building envelope, heating systems, and appliances.

Largest savings are achieved in the heating sector, with a pronounced move from fossil fuels towards environmental heat. Electricity demand for appliances grows from 300 GWh in 2015 to 380 GWh in 2050, driven by an increase in population. Towards the end of the modelling period, efficiency gains begin to offset the population growth, leading to a slight decrease in electricity demand.

Depending on the building density and specific demand, the demand maps and resp. nodal results are provided for the years 2015 (see Figure 7.2.4) and 2050 (see Figure 7.2.5). Depending on the demand classification (per parcel), different nodal aggregations can be supplied.

Spatially, final energy demand is concentrated in the urban centres and dedicated commercial zones. Through efficiency gains, energy demand can be reduced on almost all parcels, despite the growth in energy reference floor area. Only in the area of Risch, demand levels in 2050 are as high as in 2015 given the underlying growth development and stock assumptions.

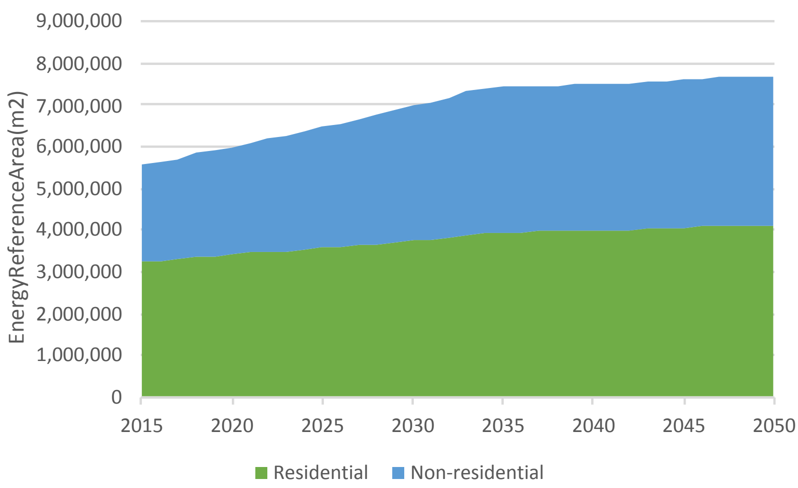

Figure 7.2.1: Expected growth of the energy reference area until 2050 in relation to the population growth and the increase in surface per capita.

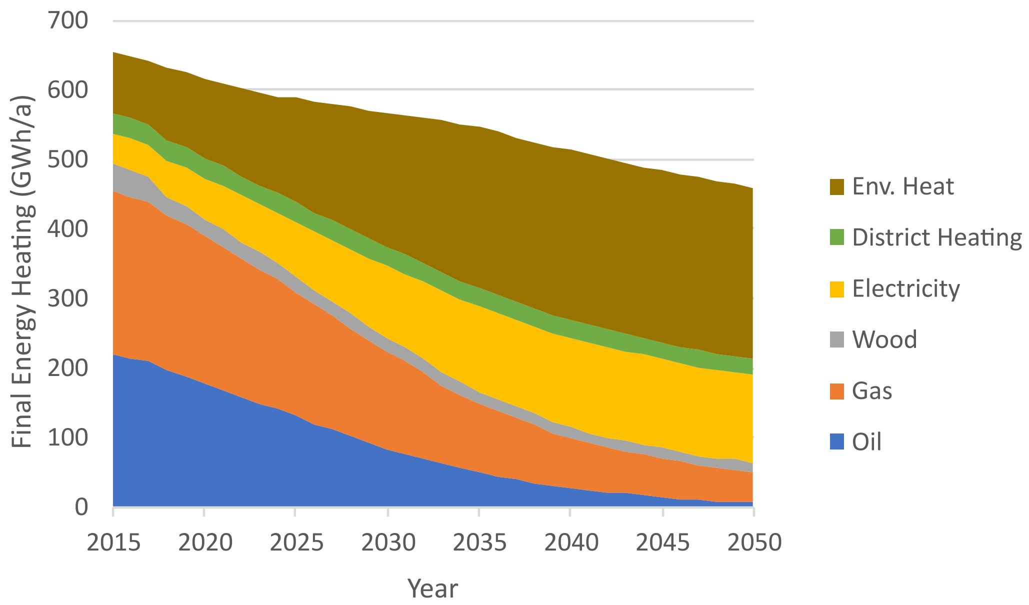

Figure 7.2.2: Annual electricity and heat demand development until 2050 for heating purposes in the observed communes.

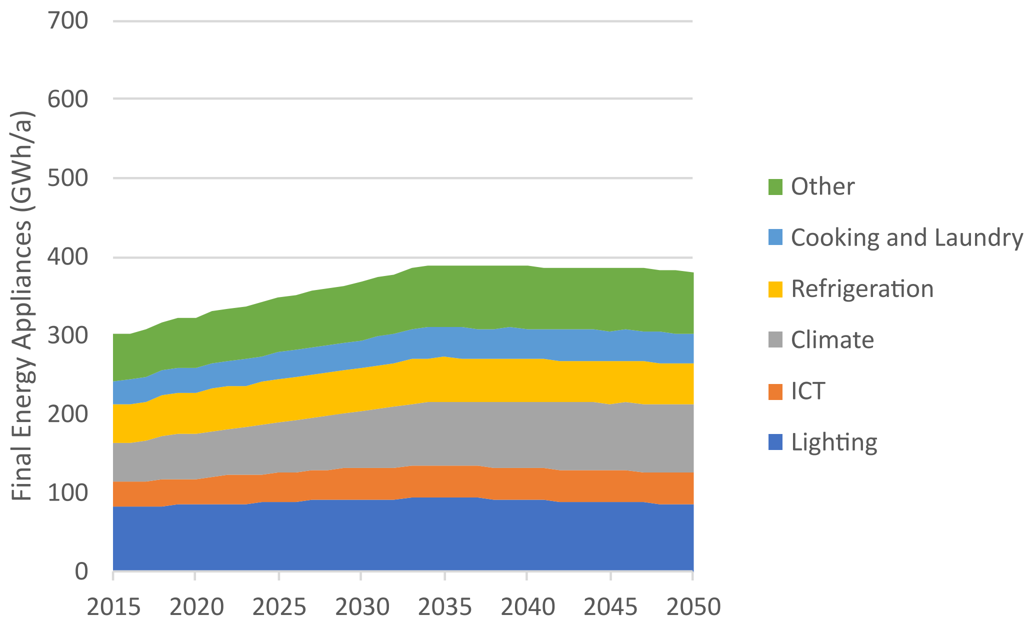

Figure 7.2.3: Annual electricity demand development until 2050 for appliances.

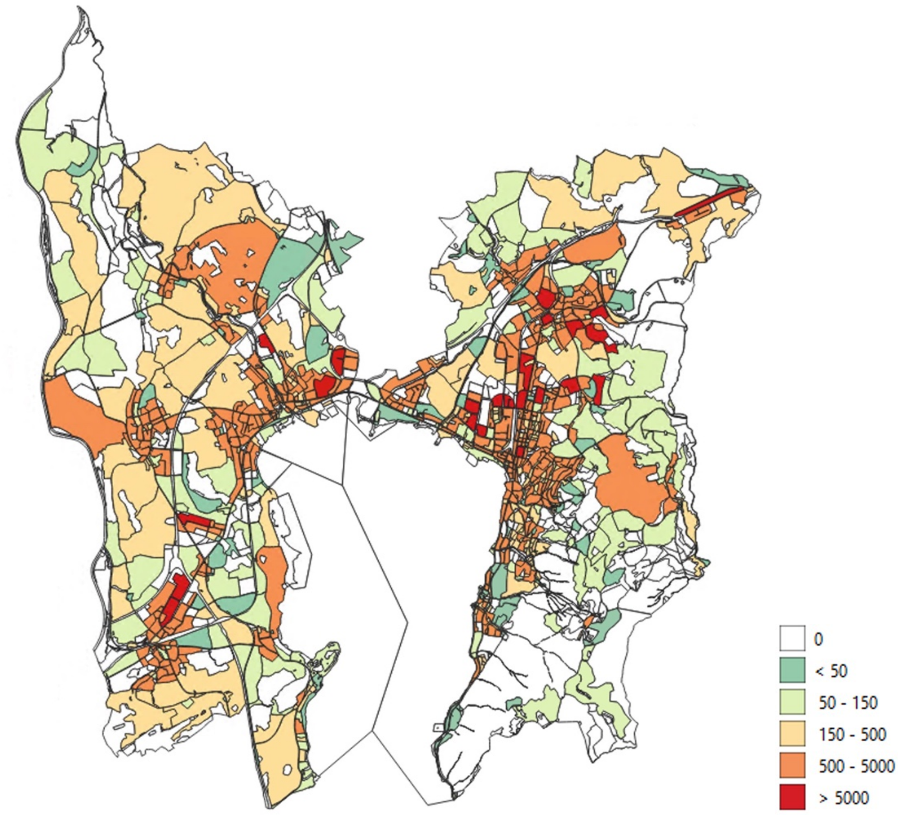

Figure 7.2.4: Spatial distribution of final energy demand for heating and electricity for the year 2015.

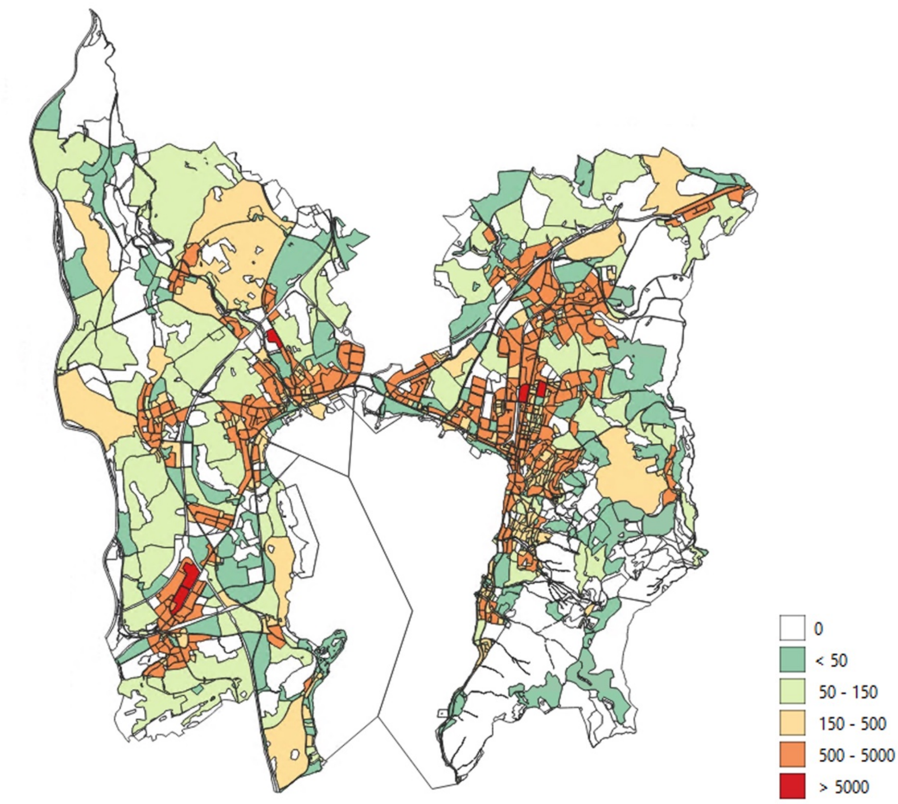

Figure 7.2.5: Spatial distribution of final energy demand for heating and electricity for the year 2050.

7.2.2 Renewable potentials

Given the current supply zones and the zoning planning, the potentials and potential zones for different heating and electricity generation technologies can be defined (see Figure 7.1.4).

The identified renewable potentials for electricity and heat are given in the following Table 7.2.1, (where * denotes that other sources [34] were also used). As can be seen, the potentials for ambient heat (ground source) and solar electricity and heat are largest and can contribute to large extent to covering heating demand in the dedicated areas. The potentials for solar heat and photovoltaics are based on the sonnendach.ch calculator developed by the Swiss Federal Office of Energy [35]. Only roof surfaces with a suitability of good, high, and very high (levels 3, 4, and 5) are considered in the current study. Ground source ambient heat potential is based on study [36], which calculates a renewable potential of 3 kWh/m^2 ground. An extended potential of 11 kWh/m2 [37] assumes active regeneration, where excess heat generated in the summer is stored in the ground. Ambient heat potential for Lake Zug is based on a potential of 100 MW as determined by [38], assuming an annual load of 1800 hours.

Energy carrier (heat)	**Additional potential[GWh/yr]**
Ground (ambient heat)	264 (969 with regeneration)
Lake (ambient heat)	150
Biomass*	< 5
Solar heat	302
Biogas (incl. ARA)*	< 8
ARA* (ambient heat)	< 14
Energy carrier (electricity)	
Photovoltaics	544
Hydro*	-
Biogas (incl. ARA)*	< 19
ARA*	< 1

Table 7.2.1: Overview of the renewable energy potentials for the Canton of Zug.

8 Optimal planning software: problem formulation

Values in red are operational variables   Values in blue are investment variables

Indices are

- subscript y for representative years $\in \{1, \cdots, y^{\text{end}}\}$
  where $y^{\text{end}} = 1 + (2050 - 2020)/\Delta y$
- subscript h for hour $\in \{1, \cdots, 24\}$
- subscript d for day $\in \{1, \cdots, 365\}$
- superscript t for technology $\in \{F, E, BP, BE\}$ (Fuelcell, Electrolyser, Battery Power, Battery Energy)

Values with a tilde ($\tilde{P}$) indicate is the installed capacity and represents the investment made in a particular year. Value with a breve ($\breve{P}$) indicate an exogenous investment that is made outside of the optimization. Values with a hat ($\hat{P}$) indicate the available capacity for use in that year which is obtained by summing the investments in previous years within the lifetime of the technology. The maximum capacity is denoted by $\overline{P}$ and is an input parameter.

Sampling is performed on the years with a discretization of Δy, i.e., the problem is solved for years $2020 + n\Delta y \quad \forall n \in [0, \ldots, y^{\text{end}} - 1]$.

The hourly discretization Δt is assumed to be 1 hour.

Objective function: The objective function minimize the investment costs and operational costs.

The technology investment cost comprises the sum of the new installed capacities $\tilde{P}^t_{i,y}$ in year y for technology t at locations $i \in \mathcal{T}^t$. The cost is annualised cost c^t_y for either the lifetime of the technology (expressed as multiple of Δy) T^t or until the end of the planning horizon denoted by y^{end}.

$$\sum_y \sum_t \sum_{i \in \mathcal{T}^t} \Delta y \times \min(T^t, y^{\text{end}} - y + 1) \times c^t_y \times \tilde{P}^t_{i,y} \tag{2}$$

> If lifetime is 20 years and the year discretization Δy is 10 years, then T^t is 2

The network investment costs comprises the annualised cost $c_{\ell,y}$ for each of the upgradeable line $\ell \in \mathcal{L}^c$. A binary decision is made about whether a line is upgraded or not. $\tilde{u}_{\ell,y}$

$$\sum_y \sum_{\ell \in \mathcal{L}^c} \Delta y \times \min(T^\ell, y^{\text{end}} - y + 1) \times c_{\ell,y} \times \tilde{u}_{\ell,y} \tag{3}$$

For each of the investments there is an ongoing O&M cost o^t_y associated with the total available capacity $\hat{P}^t_{i,y}$. This value is scaled by the discretization of the years.

$$\sum_y \sum_t \sum_{i \in \mathcal{T}^t} \Delta y \times (o^t_y \times \hat{P}^t_{i,y}) \tag{4}$$

The operational costs are scaled by Δy so that they represent the intermediate years that are skipped. Additionally they are scaled by Δt to represent the true yearly costs. The costs in a year comprise electrical energy imported from the external grid $p^{\text{ext}}_{i,h,d,y}$ at a time varying cost $c^{\text{elec}}_{h,d,y}$ and a penalty for any load spilling at cost of VoLL.

$$\sum_y \sum_d \sum_h \Delta y \times \Delta t \times \left(c^{\text{elec}}_{h,d,y} \times \sum_{i \in \mathcal{F}} p^{\text{ext}}_{i,h,d,y} + \text{VoLL} \times \sum_b L^{\text{elec,spill}}_{b,h,d,y} \right) \tag{5}$$

and the gas energy imported from the external grid $m^{\text{ext}}_{h,d,y}$ at an (annually) constant price c^{gas}_y.

$$\sum_y \sum_d \sum_h \Delta y \times \Delta t \times c^{gas}_y \times m^{\text{ext}}_{h,d,y} \tag{6}$$

The total objective function is

$$\underset{\Xi}{\text{Minimize}} \quad (2) + (3) + (4) + (5) + (6) \tag{7}$$

Investment Limits: Each technology investment is limited by its lifetime T^t and the maximum capacity that can be installed in the network $\overline{P}^t_i$. The available capacity for use in any year $\hat{P}^t_{i,y}$ is the sum of previous investments within the lifetime of the technology and any exogenously built technologies $\breve{P}^t_i$

$$\sum_{\tau=\max(1,y-T^t+1)}^{y} \tilde{P}^t_{i,\tau} \leq \overline{P}^t_i, \quad \forall i,t,y \tag{8}$$

$$\hat{P}^t_{i,y} = \sum_{\tau=\max(1,y-T^t+1)}^{y} \left(\tilde{P}^t_{i,\tau} + \breve{P}^t_{i,\tau}\right) \quad \forall i,t,y \tag{9}$$

$$\tilde{P}^t_{i,y}, \hat{P}^t_{i,y} \geq 0 \quad \forall i,t,y \tag{10}$$

The decision to make an upgrade is represented by $\tilde{u}_{\ell,y}$ and only one investment per line is allowed.

$$\sum_{y} \tilde{u}_{\ell,y} \leq 1 \quad \forall \ell \in \mathcal{L}^c \tag{11}$$

$$\tilde{u}_{\ell,y} \in \{0,1\} \quad \forall \ell \in \mathcal{L}^c, y \tag{12}$$

Additionally $\hat{u}_{\ell,y}$ denotes if a line has been upgraded in previous years, i.e. $\hat{u}_{\ell,y}$=0 means no investments have been made and the original line capacity should be used and $\hat{u}_{\ell,y}$=1 means an upgrade has been made and the new line capacity should be used.

$$\hat{u}_{\ell,y} = \sum_{\tau=\max(1,y-T^\ell+1)}^{y} \tilde{u}_{\ell,\tau} \quad \forall \ell \in \mathcal{L}^c, y \tag{13}$$

(14)

Operational Constraints

PV,Electrolyser,Fuel Cell: The PV output $p^{PV}_{i,h,d,y}$ is dependent on the available capacity which is a parameter and the pv profile $\rho^{PV}_{h,d}$ (which has units of MWh/MWp). The electrolyser and fuel cell operation is determined by the available capacity.

$$0 \le p^{PV}_{i,h,d,y} \le \rho^{PV}_{h,d} \overline{P}^{PV}_{i,y} \quad \forall i \in \mathcal{T}^{PV}, h, d, y \tag{15}$$
$$0 \le p^{\mathsf{E}}_{i,h,d,y} \le \hat{P}^{\mathsf{E}}_{i,y} \quad \forall i \in \mathcal{T}^{E}, h, d, y \tag{16}$$
$$0 \le p^{\mathsf{F}}_{i,h,d,y} \le \hat{P}^{\mathsf{F}}_{i,y} \quad \forall i \in \mathcal{T}^{F}, h, d, y, \tag{17}$$

Battery: The battery operates in the usual manner and ensures the final SOC is equal to the initial SOC at the beginning and end of each year. The initial state of charge is a fraction α^B of the available energy capacity.

$$e^{\mathsf{B}}_{i,h,d,y} = \alpha^{\mathsf{B}} \hat{P}^{BE}_{i,y} + \Delta t \eta_c p^{\mathsf{B},c}_{i,h,d,y} - \frac{\Delta t}{\eta_d} p^{\mathsf{B},d}_{i,h,d,y}, \quad \forall i \in \mathcal{T}^B, h \in \{h_1\}, d \in \{d_1\}, y \tag{18}$$
$$e^{\mathsf{B}}_{i,h,d,y} = \alpha^{\mathsf{B}} \hat{P}^{BE}_{i,y} \quad \forall i \in \mathcal{T}^B, h \in \{h_{24}\}, d \in \{d_{365}\}, y \tag{19}$$
$$e^{\mathsf{B}}_{i,h,d,y} = e^{\mathsf{B}}_{i,h-1,d,y} + \Delta t \eta_c p^{\mathsf{B},c}_{i,h,d,y} - \frac{\Delta t}{\eta_d} p^{\mathsf{B},d}_{i,h,d,y}, \quad \forall i \in \mathcal{T}^B, h, d, y \tag{20}$$
$$0 \le p^{\mathsf{B},c}_{i,h,d,y} \le \hat{P}^{\mathsf{BP}}_{i,y} \quad \forall i \in \mathcal{T}^B, h, d, y, \tag{21}$$
$$0 \le p^{\mathsf{B},d}_{i,h,d,y} \le \hat{P}^{\mathsf{BP}}_{i,y} \quad \forall i \in \mathcal{T}^B, h, d, y, \tag{22}$$
$$0 \le e^{\mathsf{B}}_{i,h,d,y} \le \hat{P}^{\mathsf{BE}}_{i,y} \quad \forall i \in \mathcal{T}^B, h, d, y, \tag{23}$$

Electrical Network: The electrical network comprises a set of busses $\mathcal{B}$ and a set of electrical lines which are modelled with a DC approximation. The line are divided into a set $\mathcal{L}$ of lines that will not be upgraded and a set of candidate lines $\mathcal{L}^c$ that could be upgraded. Before an upgrade (i.e. $\hat{u}_{\ell,y} = 0$), there lines are modelled with their initial ratings $\overline{p}_\ell$ and susceptances b_{ij} while after they are modelled with a rating $\breve{p}_\ell$ and susceptance b^{can}_{ij}.

$$p_{\ell,h,d,y} = -b_{ij}(\theta_{b_i,h,d,y} - \theta_{b_j,h,d,y}) \quad \forall \ell \in \mathcal{L}, h, d, y \tag{24}$$
$$-\overline{p}_\ell \le p_{\ell,h,d,y} \le \overline{p}_\ell \quad \forall \ell \in \mathcal{L}, h, d, y \tag{25}$$

$$-K\hat{u}_{\ell,y} \le p^{\mathsf{can}}_{\ell,h,d,y} + b_{ij}(\theta_{b_i,h,d,y} - \theta_{b_j,h,d,y}) \le K\hat{u}_{\ell,y} \quad \forall \ell \in \mathcal{L}^c, h, d, y \tag{26}$$
$$-K(1-\hat{u}_{\ell,y}) \le p^{\mathsf{can}}_{\ell,h,d,y} + b^{can}_{ij}(\theta_{b_i,h,d,y} - \theta_{b_j,h,d,y}) \le K(1-\hat{u}_{\ell,y}) \quad \forall \ell \in \mathcal{L}^c, h, d, y \tag{27}$$

$$-(1-\hat{u}_{\ell,y})\overline{p}_\ell - \hat{u}_{\ell,y}\breve{p}_\ell \le p^{\mathsf{can}}_{\ell,t,d,y} \le (1-\hat{u}_{\ell,y})\overline{p}_\ell + \hat{u}_{\ell,y}\breve{p}_\ell \quad \forall \in \mathcal{L}^c, h, d, y \tag{28}$$

One bus is chosen as the reference angle.

$$\theta_{b_1,h,d,y} = 0 \quad \forall h, d, y \tag{29}$$
$$\tag{30}$$

Bus Electrical Balance: At each bus, there is a balance between the energy imported from the external feeder, the lines connected to that bus and all connected technologies the load and customer side PV. $A_{(b,\ell)}$ is the incidence matrix and $\mathcal{M}_b^t$ maps the technologies of type t to bus b.

$$\sum_{i\in\mathcal{M}_b^{\mathcal{F}}} p^{\text{ext}}_{i,h,d,y} + A_{(b,\ell)} p_{\ell,h,d,y} + A^{can}_{(b,\ell)} p^{\text{can}}_{\ell,h,d,y} + \sum_{i\in\mathcal{M}_b^{PV}} p^{\text{PV}}_{i,h,d,y} + \sum_{i\in\mathcal{M}_b^{F}} p^{\text{F}}_{i,h,d,y} - \sum_{i\in\mathcal{M}_b^{B}} (p^{\text{B},c}_{i,h,d,y} - p^{\text{B},d}_{i,h,d,y}) - \sum_{i\in\mathcal{M}_b^{\mathcal{E}}} p^{\text{E}}_{i,h,d,y} = \sum_{i\in\mathcal{M}_b^{Load}} (L^{\text{elec}}_{i,h,d,y} - L^{\text{elec,spill}}_{i,h,d,y}) \quad \forall b,h,d,y \tag{31}$$

$$0 \leq L^{\text{elec,spill}}_{i,h,d,y} \leq L^{\text{elec}}_{i,h,d,y} \quad \forall i,h,d,y \tag{32}$$

(33)

$$\underline{p}^{\text{ext}}_{i,h,d,y} \leq p^{\text{ext}}_{i,h,d,y} \leq \overline{p}^{\text{ext}}_{i,h,d,y} \quad \forall i,h,d,y \tag{34}$$

(35)

Gas Network: The gas network is modelled as a single storage device which is used to balance the imported gas and gas produced by the electrolyser with the gas load and fuel cell demand.

$$e^G_{h,d,y} = e^G_{h-1,d,y} + \Delta t m^{\text{ext}}_{h,d,y} + \Delta t \eta^E \sum_{i\in\mathcal{T}^E} p^E_{i,h,d,y} - \frac{\Delta t}{\eta^F} \sum_{i\in\mathcal{T}^F} p^F_{i,h,d,y} - \Delta t L^{\text{gas}}_{h,d,y} \quad \forall h,d,y \tag{36}$$

$$e^G_{h_1,d_1,y} = \alpha^G \overline{e}^G + \Delta t m^{\text{ext}}_{h_1,d_1,y} + \Delta t \eta^E \sum_{i\in\mathcal{T}^E} p^E_{i,h_1,d_1,y} - \frac{\Delta t}{\eta^F} \sum_{i\in\mathcal{T}^F} p^F_{i,h_1,d_1,y} - \Delta t L^{\text{gas}}_{h_1,d_1,y} \quad \forall y \tag{37}$$

$$e^G_{h_1,d,y} = e^G_{h_{24},d-1,y} \quad \forall d,y \tag{38}$$

$$e^G_{h_{24},d_{365},y} = \alpha^G \overline{e}^G \quad \forall y \tag{39}$$

$$\underline{e}^G \leq e^G_{h,d,y} \leq \overline{e}^G \quad \forall h,d,y \tag{40}$$

The gas/hydrogen from the electrolyser should be exceed more than γ% of the total gas volume. The initial gas stored is all natural gas. Assume that the fuel cell and the load consume gas as if it was fully mixed, i.e, they do not affect the ratio only the total quantity.

$$\sum_{\tau=1}^{h}\sum_{\delta=1}^{d} \eta^E \sum_{i\in\mathcal{T}^E} P^E_{i,\tau,\delta,y} \leq \gamma\left(\alpha^G \overline{e}^G + \sum_{\tau=1}^{h}\sum_{\delta=1}^{d}\left(\eta^E \sum m^{ext}_{\tau,\delta,y} + \sum_{i\in\mathcal{T}^E} P^E_{i,\tau,\delta,y}\right)\right) \quad \forall h,d,y \tag{41}$$

8.0.1 Hydrogen Content

Ideally, want to measure the total amount of Hydrogen in the system. This would require tracking the input of gas and hydrogen separately and calculating the fraction of hydrogren γ_t in the system at every time t. It will be assumed the the gas load withdraws the mixed gas and hydrogen according to γ_t.

Using simplified notation:

1. e_t^G Gas stored at time t
2. e_t^H Hydrogen stored at time t
3. m_t Gas injected to system from external source
4. h_t Hydrogen injected to system
5. L_t Load of system
6. γ_t Fraction of hydrogen in system

The total amount of gas and hydrogen stored is

$$e_t^G = e_{t-1}^G + m_t + (1 - \gamma_t)L_t \tag{42}$$
$$e_t^H = e_{t-1}^H + h_t + \gamma_t L_t \tag{43}$$

The total energy stored is the sum of these constraints

$$e_t = e_{t-1} + m_t + h_t + L_t \tag{44}$$

Define the fraction of hydrogen (**nonlinear constraint**) and limit it to some maxmimum

$$\gamma_t = \frac{e_t^H}{e_t^G + e_t^H} = \frac{e_t^H}{e_t} \leq \overline{\gamma} \tag{45}$$

or

$$e_t^H \leq \overline{\gamma} e_t \tag{46}$$
$$e_{t-1}^H + h_t + \gamma_t L_t \leq \overline{\gamma}(e_{t-1} + m_t + h_t + L_t) \tag{47}$$

Main assumption: The load L_t decreases the amount of gas proportionally to γ_t and does not affect the ratio between them.

$$e_{t-1}^H + h_t \leq \overline{\gamma}(e_{t-1} + m_t + h_t) \tag{48}$$
$$e_0^H + \sum_{\tau=1}^{t} h_\tau \leq \overline{\gamma}(e_0 + \sum_{\tau=1}^{t}(m_\tau + h_\tau)) \quad \forall t \tag{49}$$

9 Tables with total costs

9.1 Total Cost for Circulago Scenario

#	Circulago	Demand	PV	Gas	CO2	Elec.	Customer Investment				Utility Cost			Total cost
		Scenario	Scenario	Price	Tax	Price	Heating	PV	Inv.	Circuloago	oper-elec	oper-gas	oper-total	
1	w/ Circu	Reference	Moderate	pG-l	co2-ref	pE-hS	139.58	199.92	0.13	100.00	509.24	74.05	583.28	1022.91
2	w/o Circu	Reference	Moderate	pG-l	co2-ref	pE-hS	232.40	199.92	0.69	0.00	492.69	115.82	608.51	1041.51
3	w/ Circu	Reference	Moderate	pG-l	co2-ref	pE-ref	139.58	199.92	0.00	100.00	499.45	74.48	573.94	1013.44
4	w/o Circu	Reference	Moderate	pG-l	co2-ref	pE-ref	232.40	199.92	0.00	0.00	481.88	118.12	600.00	1032.32
5	w/ Circu	Reference	Moderate	pG-l	co2-ref	pE-lM	139.58	199.92	0.12	100.00	418.48	74.03	492.51	932.13
6	w/o Circu	Reference	Moderate	pG-l	co2-ref	pE-lM	232.40	199.92	0.54	0.00	405.30	115.79	521.09	953.95
7	w/ Circu	Reference	Moderate	pG-l	co2-ref	pE-lMhS	139.58	199.92	0.21	100.00	427.34	73.98	501.32	941.03
8	w/o Circu	Reference	Moderate	pG-l	co2-ref	pE-lMhS	232.40	199.92	0.76	0.00	413.24	115.64	528.88	961.96
9	w/ Circu	Reference	Moderate	pG-ref	co2-ref	pE-hS	139.58	199.92	0.19	100.00	509.24	91.05	600.29	1039.98
10	w/o Circu	Reference	Moderate	pG-ref	co2-ref	pE-hS	232.40	199.92	0.70	0.00	492.80	141.01	633.81	1066.83
11	w/ Circu	Reference	Moderate	pG-ref	co2-ref	pE-ref	139.58	199.92	0.00	100.00	499.45	91.64	591.09	1030.59
12	w/o Circu	Reference	Moderate	pG-ref	co2-ref	pE-ref	232.40	199.92	0.00	0.00	481.88	143.91	625.79	1058.11
13	w/ Circu	Reference	Moderate	pG-ref	co2-ref	pE-lM	139.58	199.92	0.13	100.00	418.54	91.02	509.56	949.19
14	w/o Circu	Reference	Moderate	pG-ref	co2-ref	pE-lM	232.40	199.92	0.67	0.00	405.63	140.60	546.23	979.22
15	w/ Circu	Reference	Moderate	pG-ref	co2-ref	pE-lMhS	139.58	199.92	0.47	100.00	427.98	90.10	518.07	958.04
16	w/o Circu	Reference	Moderate	pG-ref	co2-ref	pE-lMhS	232.40	199.92	2.17	0.00	415.90	136.65	552.55	987.05
17	w/ Circu	Reference	Moderate	pG-h	co2-ref	pE-hS	139.58	199.92	0.81	100.00	512.24	119.45	631.70	1072.01
18	w/o Circu	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	3.61	0.00	505.85	172.19	678.04	1113.97
19	w/ Circu	Reference	Moderate	pG-h	co2-ref	pE-ref	139.58	199.92	0.68	100.00	503.03	119.56	622.59	1062.78
20	w/o Circu	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	3.08	0.00	497.94	172.60	670.54	1105.94
21	w/ Circu	Reference	Moderate	pG-h	co2-ref	pE-lM	139.58	199.92	2.37	100.00	426.87	111.82	538.69	980.55
22	w/o Circu	Reference	Moderate	pG-h	co2-ref	pE-lM	232.40	199.92	3.45	0.00	418.89	169.89	588.78	1024.54
23	w/ Circu	Reference	Moderate	pG-h	co2-ref	pE-lMhS	139.58	199.92	2.45	100.00	435.48	111.94	547.42	989.37
24	w/o Circu	Reference	Moderate	pG-h	co2-ref	pE-lMhS	232.40	199.92	3.88	0.00	425.83	170.14	595.97	1032.18
25	w/ Circu	Mild Gas	Moderate	pG-l	co2-ref	pE-hS	131.36	199.92	0.30	100.00	504.19	87.99	592.18	1023.76
26	w/o Circu	Mild Gas	Moderate	pG-l	co2-ref	pE-hS	215.27	199.92	1.35	0.00	478.81	153.98	632.78	1049.33
27	w/ Circu	Mild Gas	Moderate	pG-l	co2-ref	pE-ref	131.36	199.92	0.00	100.00	494.10	88.99	583.09	1014.37
28	w/o Circu	Mild Gas	Moderate	pG-l	co2-ref	pE-ref	215.27	199.92	0.00	0.00	466.71	158.52	625.23	1040.42
29	w/ Circu	Mild Gas	Moderate	pG-l	co2-ref	pE-lM	131.36	199.92	0.29	100.00	414.41	87.94	502.35	933.92
30	w/o Circu	Mild Gas	Moderate	pG-l	co2-ref	pE-lM	215.27	199.92	1.10	0.00	395.02	153.63	548.65	964.94
31	w/ Circu	Mild Gas	Moderate	pG-l	co2-ref	pE-lMhS	131.36	199.92	0.36	100.00	423.01	87.89	510.91	942.55
32	w/o Circu	Mild Gas	Moderate	pG-l	co2-ref	pE-lMhS	215.27	199.92	1.62	0.00	401.72	153.28	554.99	971.80
33	w/ Circu	Mild Gas	Moderate	pG-ref	co2-ref	pE-hS	131.36	199.92	0.34	100.00	504.23	107.70	611.93	1043.55
34	w/o Circu	Mild Gas	Moderate	pG-ref	co2-ref	pE-hS	215.27	199.92	1.49	0.00	479.27	186.24	665.51	1082.19
35	w/ Circu	Mild Gas	Moderate	pG-ref	co2-ref	pE-ref	131.36	199.92	0.00	100.00	494.10	108.99	603.09	1034.37
36	w/o Circu	Mild Gas	Moderate	pG-ref	co2-ref	pE-ref	215.27	199.92	0.00	0.00	466.71	192.41	659.11	1074.30
37	w/ Circu	Mild Gas	Moderate	pG-ref	co2-ref	pE-lM	131.36	199.92	0.29	100.00	414.56	107.56	522.12	953.69
38	w/o Circu	Mild Gas	Moderate	pG-ref	co2-ref	pE-lM	215.27	199.92	1.41	0.00	395.72	185.40	581.12	997.72
39	w/ Circu	Mild Gas	Moderate	pG-ref	co2-ref	pE-lMhS	131.36	199.92	0.94	100.00	424.13	105.89	530.03	962.25
40	w/o Circu	Mild Gas	Moderate	pG-ref	co2-ref	pE-lMhS	215.27	199.92	3.86	0.00	406.34	178.88	585.22	1004.27
41	w/ Circu	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	131.36	199.92	1.54	100.00	509.71	138.09	647.80	1080.62
42	w/o Circu	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	5.87	0.00	498.33	223.79	722.12	1143.18
43	w/ Circu	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	131.36	199.92	1.31	100.00	500.89	138.26	639.15	1071.73
44	w/o Circu	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	5.06	0.00	492.77	223.55	716.33	1136.58
45	w/ Circu	Mild Gas	Moderate	pG-h	co2-ref	pE-lM	131.36	199.92	2.96	100.00	425.09	130.42	555.51	989.76
46	w/o Circu	Mild Gas	Moderate	pG-h	co2-ref	pE-lM	215.27	199.92	5.27	0.00	413.81	221.70	635.51	1055.97
47	w/ Circu	Mild Gas	Moderate	pG-h	co2-ref	pE-lMhS	131.36	199.92	3.12	100.00	433.15	130.68	563.83	998.23
48	w/o Circu	Mild Gas	Moderate	pG-h	co2-ref	pE-lMhS	215.27	199.92	6.43	0.00	419.51	221.05	640.56	1062.18
49	w/ Circu	Reference	Reference	pG-l	co2-ref	pE-hS	139.58	387.33	0.13	100.00	416.86	74.05	490.91	1117.95
50	w/o Circu	Reference	Reference	pG-l	co2-ref	pE-hS	232.40	387.33	0.69	0.00	400.32	115.82	516.13	1136.55
51	w/ Circu	Reference	Reference	pG-l	co2-ref	pE-ref	139.58	387.33	0.00	100.00	404.14	74.48	478.62	1105.53
52	w/o Circu	Reference	Reference	pG-l	co2-ref	pE-ref	232.40	387.33	0.00	0.00	386.57	118.12	504.69	1124.42
53	w/ Circu	Reference	Reference	pG-l	co2-ref	pE-lM	139.58	387.33	0.12	100.00	345.18	74.03	419.21	1046.25
54	w/o Circu	Reference	Reference	pG-l	co2-ref	pE-lM	232.40	387.33	0.54	0.00	332.00	115.79	447.80	1068.07
55	w/ Circu	Reference	Reference	pG-l	co2-ref	pE-lMhS	139.58	387.33	0.21	100.00	356.65	73.98	430.63	1057.76
56	w/o Circu	Reference	Reference	pG-l	co2-ref	pE-lMhS	232.40	387.33	0.76	0.00	342.55	115.64	458.19	1078.69
57	w/ Circu	Reference	Reference	pG-ref	co2-ref	pE-hS	139.58	387.33	0.19	100.00	416.86	91.05	507.91	1135.02
58	w/o Circu	Reference	Reference	pG-ref	co2-ref	pE-hS	232.40	387.33	0.70	0.00	400.43	141.01	541.44	1161.86
59	w/ Circu	Reference	Reference	pG-ref	co2-ref	pE-ref	139.58	387.33	0.00	100.00	404.14	91.64	495.78	1122.69
60	w/o Circu	Reference	Reference	pG-ref	co2-ref	pE-ref	232.40	387.33	0.00	0.00	386.57	143.91	530.48	1150.21
61	w/ Circu	Reference	Reference	pG-ref	co2-ref	pE-lM	139.58	387.33	0.13	100.00	345.25	91.02	436.27	1063.30
62	w/o Circu	Reference	Reference	pG-ref	co2-ref	pE-lM	232.40	387.33	0.67	0.00	332.34	140.60	472.94	1093.34
63	w/ Circu	Reference	Reference	pG-ref	co2-ref	pE-lMhS	139.58	387.33	0.47	100.00	357.29	90.10	447.39	1074.77

Continued on next page

#	Circulago	Demand	PV	Gas	CO2	Elec.	Customer Investment				Utility Cost			Total cost
		Scenario	Scenario	Price	Tax	Price	Heating	PV	Inv.	Circuloago	oper-elec	oper-gas	oper-total	
64	w/o Circu	Reference	Reference	pG-ref	co2-ref	pE-lMhS	232.40	387.33	2.17	0.00	345.22	136.65	481.87	1103.77
65	w/ Circu	Reference	Reference	pG-h	co2-ref	pE-hS	139.58	387.33	0.81	100.00	419.87	119.45	539.32	1167.04
66	w/o Circu	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	3.61	0.00	413.47	172.19	585.67	1209.01
67	w/ Circu	Reference	Reference	pG-h	co2-ref	pE-ref	139.58	387.33	0.68	100.00	407.72	119.56	527.28	1154.87
68	w/o Circu	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	3.08	0.00	402.63	172.60	575.23	1198.04
69	w/ Circu	Reference	Reference	pG-h	co2-ref	pE-lM	139.58	387.33	2.37	100.00	353.57	111.82	465.39	1094.67
70	w/o Circu	Reference	Reference	pG-h	co2-ref	pE-lM	232.40	387.33	3.45	0.00	345.59	169.89	515.48	1138.66
71	w/ Circu	Reference	Reference	pG-h	co2-ref	pE-lMhS	139.58	387.33	2.45	100.00	364.79	111.94	476.73	1106.09
72	w/o Circu	Reference	Reference	pG-h	co2-ref	pE-lMhS	232.40	387.33	3.88	0.00	355.15	170.14	525.28	1148.90
73	w/ Circu	Mild Gas	Reference	pG-l	co2-ref	pE-hS	131.36	387.33	0.30	100.00	411.82	87.99	499.80	1118.80
74	w/o Circu	Mild Gas	Reference	pG-l	co2-ref	pE-hS	215.27	387.33	1.35	0.00	386.43	153.98	540.41	1144.36
75	w/ Circu	Mild Gas	Reference	pG-l	co2-ref	pE-ref	131.36	387.33	0.00	100.00	398.78	88.99	487.77	1106.46
76	w/o Circu	Mild Gas	Reference	pG-l	co2-ref	pE-ref	215.27	387.33	0.00	0.00	371.40	158.52	529.92	1132.52
77	w/ Circu	Mild Gas	Reference	pG-l	co2-ref	pE-lM	131.36	387.33	0.29	100.00	341.11	87.94	429.06	1048.03
78	w/o Circu	Mild Gas	Reference	pG-l	co2-ref	pE-lM	215.27	387.33	1.10	0.00	321.72	153.63	475.35	1079.05
79	w/ Circu	Mild Gas	Reference	pG-l	co2-ref	pE-lMhS	131.36	387.33	0.36	100.00	352.33	87.89	440.22	1059.27
80	w/o Circu	Mild Gas	Reference	pG-l	co2-ref	pE-lMhS	215.27	387.33	1.62	0.00	331.03	153.28	484.31	1088.52
81	w/ Circu	Mild Gas	Reference	pG-ref	co2-ref	pE-hS	131.36	387.33	0.34	100.00	411.86	107.70	519.56	1138.59
82	w/o Circu	Mild Gas	Reference	pG-ref	co2-ref	pE-hS	215.27	387.33	1.49	0.00	386.89	186.24	573.14	1177.23
83	w/ Circu	Mild Gas	Reference	pG-ref	co2-ref	pE-ref	131.36	387.33	0.00	100.00	398.78	108.99	507.78	1126.47
84	w/o Circu	Mild Gas	Reference	pG-ref	co2-ref	pE-ref	215.27	387.33	0.00	0.00	371.40	192.41	563.80	1166.40
85	w/ Circu	Mild Gas	Reference	pG-ref	co2-ref	pE-lM	131.36	387.33	0.29	100.00	341.27	107.56	448.83	1067.81
86	w/o Circu	Mild Gas	Reference	pG-ref	co2-ref	pE-lM	215.27	387.33	1.41	0.00	322.43	185.40	507.83	1111.84
87	w/ Circu	Mild Gas	Reference	pG-ref	co2-ref	pE-lMhS	131.36	387.33	0.94	100.00	353.45	105.89	459.34	1078.97
88	w/o Circu	Mild Gas	Reference	pG-ref	co2-ref	pE-lMhS	215.27	387.33	3.86	0.00	335.66	178.88	514.53	1120.99
89	w/ Circu	Mild Gas	Reference	pG-h	co2-ref	pE-hS	131.36	387.33	1.54	100.00	417.34	138.09	555.43	1175.66
90	w/o Circu	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	5.87	0.00	405.95	223.79	629.74	1238.21
91	w/ Circu	Mild Gas	Reference	pG-h	co2-ref	pE-ref	131.36	387.33	1.31	100.00	405.57	138.26	543.83	1163.83
92	w/o Circu	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	5.06	0.00	397.46	223.55	621.02	1228.68
93	w/ Circu	Mild Gas	Reference	pG-h	co2-ref	pE-lM	131.36	387.33	2.96	100.00	351.79	130.42	482.22	1103.87
94	w/o Circu	Mild Gas	Reference	pG-h	co2-ref	pE-lM	215.27	387.33	5.27	0.00	340.52	221.70	562.22	1170.09
95	w/ Circu	Mild Gas	Reference	pG-h	co2-ref	pE-lMhS	131.36	387.33	3.12	100.00	362.46	130.68	493.14	1114.95
96	w/o Circu	Mild Gas	Reference	pG-h	co2-ref	pE-lMhS	215.27	387.33	6.43	0.00	348.82	221.05	569.87	1178.91
97	w/ Circu	Reference	High	pG-l	co2-ref	pE-hS	139.58	495.40	0.13	100.00	368.69	74.05	442.74	1177.85
98	w/o Circu	Reference	High	pG-l	co2-ref	pE-hS	232.40	495.40	0.69	0.00	352.15	115.82	467.96	1196.45
99	w/ Circu	Reference	High	pG-l	co2-ref	pE-ref	139.58	495.40	0.00	100.00	355.10	74.48	429.58	1164.56
100	w/o Circu	Reference	High	pG-l	co2-ref	pE-ref	232.40	495.40	0.00	0.00	337.53	118.12	455.64	1183.44
101	w/ Circu	Reference	High	pG-l	co2-ref	pE-lM	139.58	495.40	0.12	100.00	304.55	74.03	378.58	1113.68
102	w/o Circu	Reference	High	pG-l	co2-ref	pE-lM	232.40	495.40	0.54	0.00	291.37	115.79	407.16	1135.50
103	w/ Circu	Reference	High	pG-l	co2-ref	pE-lMhS	139.58	495.40	0.21	100.00	316.80	73.98	390.78	1125.97
104	w/o Circu	Reference	High	pG-l	co2-ref	pE-lMhS	232.40	495.40	0.76	0.00	302.70	115.64	418.34	1146.90
105	w/ Circu	Reference	High	pG-ref	co2-ref	pE-hS	139.58	495.40	0.19	100.00	368.69	91.05	459.74	1194.92
106	w/o Circu	Reference	High	pG-ref	co2-ref	pE-hS	232.40	495.40	0.70	0.00	352.26	141.01	493.27	1221.76
107	w/ Circu	Reference	High	pG-ref	co2-ref	pE-ref	139.58	495.40	0.00	100.00	355.10	91.64	446.74	1181.72
108	w/o Circu	Reference	High	pG-ref	co2-ref	pE-ref	232.40	495.40	0.00	0.00	337.53	143.91	481.44	1209.24
109	w/ Circu	Reference	High	pG-ref	co2-ref	pE-lM	139.58	495.40	0.13	100.00	304.61	91.02	395.63	1130.74
110	w/o Circu	Reference	High	pG-ref	co2-ref	pE-lM	232.40	495.40	0.67	0.00	291.70	140.60	432.30	1160.77
111	w/ Circu	Reference	High	pG-ref	co2-ref	pE-lMhS	139.58	495.40	0.47	100.00	317.43	90.10	407.53	1142.98
112	w/o Circu	Reference	High	pG-ref	co2-ref	pE-lMhS	232.40	495.40	2.17	0.00	305.36	136.65	442.01	1171.98
113	w/ Circu	Reference	High	pG-h	co2-ref	pE-hS	139.58	495.40	0.81	100.00	371.70	119.45	491.15	1226.94
114	w/o Circu	Reference	High	pG-h	co2-ref	pE-hS	232.40	495.40	3.61	0.00	365.30	172.19	537.50	1268.91
115	w/ Circu	Reference	High	pG-h	co2-ref	pE-ref	139.58	495.40	0.68	100.00	358.68	119.56	478.24	1213.90
116	w/o Circu	Reference	High	pG-h	co2-ref	pE-ref	232.40	495.40	3.08	0.00	353.59	172.60	526.19	1257.07
117	w/ Circu	Reference	High	pG-h	co2-ref	pE-lM	139.58	495.40	2.37	100.00	312.94	111.82	424.76	1162.10
118	w/o Circu	Reference	High	pG-h	co2-ref	pE-lM	232.40	495.40	3.45	0.00	304.96	169.89	474.85	1206.09
119	w/ Circu	Reference	High	pG-h	co2-ref	pE-lMhS	139.58	495.40	2.45	100.00	324.94	111.94	436.87	1174.30
120	w/o Circu	Reference	High	pG-h	co2-ref	pE-lMhS	232.40	495.40	3.88	0.00	315.29	170.14	485.43	1217.11
121	w/ Circu	Mild Gas	High	pG-l	co2-ref	pE-hS	131.36	495.40	0.30	100.00	363.65	87.99	451.64	1178.70
122	w/o Circu	Mild Gas	High	pG-l	co2-ref	pE-hS	215.27	495.40	1.35	0.00	338.27	153.98	492.24	1204.26
123	w/ Circu	Mild Gas	High	pG-l	co2-ref	pE-ref	131.36	495.40	0.00	100.00	349.74	88.99	438.73	1165.49
124	w/o Circu	Mild Gas	High	pG-l	co2-ref	pE-ref	215.27	495.40	0.00	0.00	322.35	158.52	480.88	1191.55
125	w/ Circu	Mild Gas	High	pG-l	co2-ref	pE-lM	131.36	495.40	0.29	100.00	300.48	87.94	388.42	1115.47
126	w/o Circu	Mild Gas	High	pG-l	co2-ref	pE-lM	215.27	495.40	1.10	0.00	281.09	153.63	434.72	1146.49
127	w/ Circu	Mild Gas	High	pG-l	co2-ref	pE-lMhS	131.36	495.40	0.36	100.00	312.47	87.89	400.36	1127.48
128	w/o Circu	Mild Gas	High	pG-l	co2-ref	pE-lMhS	215.27	495.40	1.62	0.00	291.17	153.28	444.45	1156.74
129	w/ Circu	Mild Gas	High	pG-ref	co2-ref	pE-hS	131.36	495.40	0.34	100.00	363.69	107.70	471.39	1198.49
130	w/o Circu	Mild Gas	High	pG-ref	co2-ref	pE-hS	215.27	495.40	1.49	0.00	338.73	186.24	524.97	1237.13
131	w/ Circu	Mild Gas	High	pG-ref	co2-ref	pE-ref	131.36	495.40	0.00	100.00	349.74	108.99	458.74	1185.50
132	w/o Circu	Mild Gas	High	pG-ref	co2-ref	pE-ref	215.27	495.40	0.00	0.00	322.35	192.41	514.76	1225.43
133	w/ Circu	Mild Gas	High	pG-ref	co2-ref	pE-lM	131.36	495.40	0.29	100.00	300.63	107.56	408.19	1135.24

Continued on next page

#	Circulago	Demand	PV	Gas	CO2	Elec.	Customer Investment		Inv.		Utility Cost			Total cost
		Scenario	Scenario	Price	Tax	Price	Heating	PV	Inv.	Circuloago	oper-elec	oper-gas	oper-total	
134	w/o Circu	Mild Gas	High	pG-ref	co2-ref	pE-IM	215.27	495.40	1.41	0.00	281.79	185.40	467.19	1179.27
135	w/ Circu	Mild Gas	High	pG-ref	co2-ref	pE-IMhS	131.36	495.40	0.94	100.00	313.59	105.89	419.48	1147.18
136	w/o Circu	Mild Gas	High	pG-ref	co2-ref	pE-IMhS	215.27	495.40	3.86	0.00	295.80	178.88	474.68	1189.20
137	w/ Circu	Mild Gas	High	pG-h	co2-ref	pE-hS	131.36	495.40	1.54	100.00	369.17	138.09	507.26	1235.56
138	w/o Circu	Mild Gas	High	pG-h	co2-ref	pE-hS	215.27	495.40	5.87	0.00	357.78	223.79	581.57	1298.12
139	w/ Circu	Mild Gas	High	pG-h	co2-ref	pE-ref	131.36	495.40	1.31	100.00	356.53	138.26	494.79	1222.86
140	w/o Circu	Mild Gas	High	pG-h	co2-ref	pE-ref	215.27	495.40	5.06	0.00	348.42	223.55	571.98	1287.71
141	w/ Circu	Mild Gas	High	pG-h	co2-ref	pE-IM	131.36	495.40	2.96	100.00	311.16	130.42	441.58	1171.31
142	w/o Circu	Mild Gas	High	pG-h	co2-ref	pE-IM	215.27	495.40	5.27	0.00	299.88	221.70	521.58	1237.52
143	w/ Circu	Mild Gas	High	pG-h	co2-ref	pE-IMhS	131.36	495.40	3.12	100.00	322.60	130.68	453.28	1183.17
144	w/o Circu	Mild Gas	High	pG-h	co2-ref	pE-IMhS	215.27	495.40	6.43	0.00	308.97	221.05	530.02	1247.12

9.2 Total Cost for FuelCell Scenario

#	FuelCell	Demand	PV	Gas	CO2	Elec.	Customer Investment		Utility Cost				Total cost
		Scenario	Scenario	Price	Tax	Price	Heating	PV	Inv.	oper-elec	oper-gas	oper-total	
1	Reference	Reference	Moderate	pG-l	co2-fix	pE-ref	232.40	199.92	0.00	481.88	92.42	574.30	1006.62
2	FC50	Reference	Moderate	pG-l	co2-fix	pE-ref	224.89	199.92	0.00	429.82	169.57	599.39	1024.20
3	FC100	Reference	Moderate	pG-l	co2-fix	pE-ref	228.53	199.92	0.00	378.19	246.05	624.24	1052.69
4	Reference	Reference	Moderate	pG-l	co2-ref	pE-ref	232.40	199.92	0.00	481.88	118.12	600.00	1032.32
5	FC50	Reference	Moderate	pG-l	co2-ref	pE-ref	224.89	199.92	0.00	429.82	232.05	661.87	1086.68
6	FC100	Reference	Moderate	pG-l	co2-ref	pE-ref	228.53	199.92	0.00	378.19	344.97	723.16	1151.61
7	Reference	Reference	Moderate	pG-l	co2-fix	pE-hS	232.40	199.92	0.00	491.18	92.42	583.60	1015.92
8	FC50	Reference	Moderate	pG-l	co2-fix	pE-hS	224.89	199.92	0.00	438.28	169.57	607.85	1032.66
9	FC100	Reference	Moderate	pG-l	co2-fix	pE-hS	228.53	199.92	0.00	385.82	246.05	631.87	1060.32
10	Reference	Reference	Moderate	pG-l	co2-ref	pE-hS	232.40	199.92	0.69	492.69	115.82	608.51	1041.51
11	FC50	Reference	Moderate	pG-l	co2-ref	pE-hS	224.89	199.92	3.21	445.37	221.37	666.74	1094.76
12	FC100	Reference	Moderate	pG-l	co2-ref	pE-hS	228.53	199.92	5.13	397.02	328.03	725.05	1158.63
13	Reference	Reference	Moderate	pG-ref	co2-fix	pE-ref	232.40	199.92	0.00	481.88	118.21	600.09	1032.41
14	FC50	Reference	Moderate	pG-ref	co2-fix	pE-ref	224.89	199.92	0.00	429.82	218.45	648.27	1073.08
15	FC100	Reference	Moderate	pG-ref	co2-fix	pE-ref	228.53	199.92	0.00	378.19	317.82	696.01	1124.46
16	Reference	Reference	Moderate	pG-ref	co2-ref	pE-ref	232.40	199.92	0.00	481.88	143.91	625.79	1058.11
17	FC50	Reference	Moderate	pG-ref	co2-ref	pE-ref	224.89	199.92	0.00	429.82	280.93	710.74	1135.55
18	FC100	Reference	Moderate	pG-ref	co2-ref	pE-ref	228.53	199.92	0.00	378.19	416.74	794.93	1223.38
19	Reference	Reference	Moderate	pG-ref	co2-fix	pE-hS	232.40	199.92	0.00	491.18	118.21	609.39	1041.71
20	FC50	Reference	Moderate	pG-ref	co2-fix	pE-hS	224.89	199.92	0.00	438.28	218.45	656.73	1081.54
21	FC100	Reference	Moderate	pG-ref	co2-fix	pE-hS	228.53	199.92	0.00	385.82	317.82	703.64	1132.09
22	Reference	Reference	Moderate	pG-ref	co2-ref	pE-hS	232.40	199.92	0.70	492.80	141.01	633.81	1066.83
23	FC50	Reference	Moderate	pG-ref	co2-ref	pE-hS	224.89	199.92	3.73	446.95	265.64	712.60	1141.14
24	FC100	Reference	Moderate	pG-ref	co2-ref	pE-hS	228.53	199.92	7.04	401.60	388.87	790.46	1225.95
25	Reference	Reference	Moderate	pG-h	co2-fix	pE-ref	232.40	199.92	0.00	481.88	166.82	648.70	1081.02
26	FC50	Reference	Moderate	pG-h	co2-fix	pE-ref	224.89	199.92	0.00	429.82	310.56	740.38	1165.19
27	FC100	Reference	Moderate	pG-h	co2-fix	pE-ref	228.53	199.92	0.00	378.19	453.09	831.27	1259.72
28	Reference	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	3.08	497.94	172.60	670.54	1105.94
29	FC50	Reference	Moderate	pG-h	co2-ref	pE-ref	224.89	199.92	8.26	471.80	319.11	790.91	1223.97
30	FC100	Reference	Moderate	pG-h	co2-ref	pE-ref	228.53	199.92	12.40	442.76	468.51	911.26	1352.12
31	Reference	Reference	Moderate	pG-h	co2-fix	pE-hS	232.40	199.92	0.70	492.83	163.71	656.54	1089.56
32	FC50	Reference	Moderate	pG-h	co2-fix	pE-hS	224.89	199.92	3.86	447.07	294.09	741.16	1169.82
33	FC100	Reference	Moderate	pG-h	co2-fix	pE-hS	228.53	199.92	7.05	401.85	423.22	825.07	1260.57
34	Reference	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	3.61	505.85	172.19	678.04	1113.97
35	FC50	Reference	Moderate	pG-h	co2-ref	pE-hS	224.89	199.92	9.83	472.36	319.84	792.20	1226.83
36	FC100	Reference	Moderate	pG-h	co2-ref	pE-hS	228.53	199.92	15.90	438.45	467.09	905.54	1349.89
37	Reference	Reference	Reference	pG-l	co2-fix	pE-ref	232.40	387.33	0.00	386.57	92.42	478.99	1098.72
38	FC50	Reference	Reference	pG-l	co2-fix	pE-ref	224.89	387.33	0.00	334.51	169.57	504.08	1116.30
39	FC100	Reference	Reference	pG-l	co2-fix	pE-ref	228.53	387.33	0.00	282.88	246.05	528.92	1144.78
40	Reference	Reference	Reference	pG-l	co2-ref	pE-ref	232.40	387.33	0.00	386.57	118.12	504.69	1124.42
41	FC50	Reference	Reference	pG-l	co2-ref	pE-ref	224.89	387.33	0.00	334.51	232.05	566.55	1178.77
42	FC100	Reference	Reference	pG-l	co2-ref	pE-ref	228.53	387.33	0.00	282.88	344.97	627.84	1243.70
43	Reference	Reference	Reference	pG-l	co2-fix	pE-hS	232.40	387.33	0.00	398.80	92.42	491.22	1110.95
44	FC50	Reference	Reference	pG-l	co2-fix	pE-hS	224.89	387.33	0.00	345.91	169.57	515.48	1127.70
45	FC100	Reference	Reference	pG-l	co2-fix	pE-hS	228.53	387.33	0.00	293.45	246.05	539.49	1155.35
46	Reference	Reference	Reference	pG-l	co2-ref	pE-hS	232.40	387.33	0.69	400.32	115.82	516.13	1136.55
47	FC50	Reference	Reference	pG-l	co2-ref	pE-hS	224.89	387.33	3.21	353.00	221.37	574.37	1189.80
48	FC100	Reference	Reference	pG-l	co2-ref	pE-hS	228.53	387.33	5.14	304.66	328.01	632.67	1253.66
49	Reference	Reference	Reference	pG-ref	co2-fix	pE-ref	232.40	387.33	0.00	386.57	118.21	504.78	1124.51
50	FC50	Reference	Reference	pG-ref	co2-fix	pE-ref	224.89	387.33	0.00	334.51	218.45	552.95	1165.17
51	FC100	Reference	Reference	pG-ref	co2-fix	pE-ref	228.53	387.33	0.00	282.88	317.82	600.70	1216.56
52	Reference	Reference	Reference	pG-ref	co2-ref	pE-ref	232.40	387.33	0.00	386.57	143.91	530.48	1150.21
53	FC50	Reference	Reference	pG-ref	co2-ref	pE-ref	224.89	387.33	0.00	334.51	280.93	615.43	1227.65
54	FC100	Reference	Reference	pG-ref	co2-ref	pE-ref	228.53	387.33	0.00	282.88	416.74	699.62	1315.48
55	Reference	Reference	Reference	pG-ref	co2-fix	pE-hS	232.40	387.33	0.00	398.80	118.21	517.02	1136.75
56	FC50	Reference	Reference	pG-ref	co2-fix	pE-hS	224.89	387.33	0.00	345.91	218.45	564.35	1176.57
57	FC100	Reference	Reference	pG-ref	co2-fix	pE-hS	228.53	387.33	0.00	293.45	317.82	611.27	1227.13
58	Reference	Reference	Reference	pG-ref	co2-ref	pE-hS	232.40	387.33	0.70	400.43	141.01	541.44	1161.86
59	FC50	Reference	Reference	pG-ref	co2-ref	pE-hS	224.89	387.33	3.73	354.58	265.64	620.22	1236.18
60	FC100	Reference	Reference	pG-ref	co2-ref	pE-hS	228.53	387.33	7.04	309.22	388.87	698.09	1320.99
61	Reference	Reference	Reference	pG-h	co2-fix	pE-ref	232.40	387.33	0.00	386.57	166.82	553.39	1173.12
62	FC50	Reference	Reference	pG-h	co2-fix	pE-ref	224.89	387.33	0.00	334.51	310.56	645.07	1257.29
63	FC100	Reference	Reference	pG-h	co2-fix	pE-ref	228.53	387.33	0.00	282.88	453.09	735.96	1351.82
64	Reference	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	3.08	402.63	172.60	575.23	1198.04
65	FC50	Reference	Reference	pG-h	co2-ref	pE-ref	224.89	387.33	8.26	376.49	319.11	695.59	1316.07
66	FC100	Reference	Reference	pG-h	co2-ref	pE-ref	228.53	387.33	12.40	347.45	468.51	815.95	1444.22
67	Reference	Reference	Reference	pG-h	co2-fix	pE-hS	232.40	387.33	0.70	400.45	163.71	564.16	1184.59

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#	FuelCell	Demand	PV	Gas	CO2	Elec.	Customer Investment		Utility Cost				Total cost
		Scenario	Scenario	Price	Tax	Price	Heating	PV	Inv.	oper-elec	oper-gas	oper-total	
68	FC50	Reference	Reference	pG-h	co2-fix	pE-hS	224.89	387.33	3.86	354.69	294.09	648.78	1264.86
69	FC100	Reference	Reference	pG-h	co2-fix	pE-hS	228.53	387.33	7.05	309.47	423.22	732.69	1355.60
70	Reference	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	3.61	413.47	172.19	585.67	1209.01
71	FC50	Reference	Reference	pG-h	co2-ref	pE-hS	224.89	387.33	9.83	379.98	319.84	699.82	1321.87
72	FC100	Reference	Reference	pG-h	co2-ref	pE-hS	228.53	387.33	15.90	346.07	467.09	813.16	1444.93
73	Reference	Reference	High	pG-l	co2-fix	pE-ref	232.40	495.40	0.00	337.53	92.42	429.95	1157.75
74	FC50	Reference	High	pG-l	co2-fix	pE-ref	224.89	495.40	0.00	285.47	169.57	455.03	1175.32
75	FC100	Reference	High	pG-l	co2-fix	pE-ref	228.53	495.40	0.00	233.84	246.05	479.88	1203.81
76	Reference	Reference	High	pG-l	co2-ref	pE-ref	232.40	495.40	0.00	337.53	118.12	455.64	1183.44
77	FC50	Reference	High	pG-l	co2-ref	pE-ref	224.89	495.40	0.00	285.47	232.05	517.51	1237.80
78	FC100	Reference	High	pG-l	co2-ref	pE-ref	228.53	495.40	0.00	233.84	344.97	578.80	1302.73
79	Reference	Reference	High	pG-l	co2-fix	pE-hS	232.40	495.40	0.00	350.64	92.42	443.06	1170.86
80	FC50	Reference	High	pG-l	co2-fix	pE-hS	224.89	495.40	0.00	297.74	169.57	467.31	1187.60
81	FC100	Reference	High	pG-l	co2-fix	pE-hS	228.53	495.40	0.00	245.28	246.05	491.32	1215.25
82	Reference	Reference	High	pG-l	co2-ref	pE-hS	232.40	495.40	0.69	352.15	115.82	467.96	1196.45
83	FC50	Reference	High	pG-l	co2-ref	pE-hS	224.89	495.40	3.21	304.83	221.37	526.20	1249.70
84	FC100	Reference	High	pG-l	co2-ref	pE-hS	228.53	495.40	5.13	256.48	328.03	584.50	1313.57
85	Reference	Reference	High	pG-ref	co2-fix	pE-ref	232.40	495.40	0.00	337.53	118.21	455.74	1183.54
86	FC50	Reference	High	pG-ref	co2-fix	pE-ref	224.89	495.40	0.00	285.47	218.45	503.91	1224.20
87	FC100	Reference	High	pG-ref	co2-fix	pE-ref	228.53	495.40	0.00	233.84	317.82	551.66	1275.59
88	Reference	Reference	High	pG-ref	co2-ref	pE-ref	232.40	495.40	0.00	337.53	143.91	481.44	1209.24
89	FC50	Reference	High	pG-ref	co2-ref	pE-ref	224.89	495.40	0.00	285.47	280.93	566.39	1286.68
90	FC100	Reference	High	pG-ref	co2-ref	pE-ref	228.53	495.40	0.00	233.84	416.74	650.58	1374.51
91	Reference	Reference	High	pG-ref	co2-fix	pE-hS	232.40	495.40	0.00	350.64	118.21	468.85	1196.65
92	FC50	Reference	High	pG-ref	co2-fix	pE-hS	224.89	495.40	0.00	297.74	218.45	516.19	1236.48
93	FC100	Reference	High	pG-ref	co2-fix	pE-hS	228.53	495.40	0.00	245.28	317.82	563.10	1287.03
94	Reference	Reference	High	pG-ref	co2-ref	pE-hS	232.40	495.40	0.70	352.26	141.01	493.27	1221.76
95	FC50	Reference	High	pG-ref	co2-ref	pE-hS	224.89	495.40	3.73	306.41	265.64	572.05	1296.08
96	FC100	Reference	High	pG-ref	co2-ref	pE-hS	228.53	495.40	7.04	261.05	388.87	649.92	1380.89
97	Reference	Reference	High	pG-h	co2-fix	pE-ref	232.40	495.40	0.00	337.53	166.82	504.35	1232.15
98	FC50	Reference	High	pG-h	co2-fix	pE-ref	224.89	495.40	0.00	285.47	310.56	596.03	1316.32
99	FC100	Reference	High	pG-h	co2-fix	pE-ref	228.53	495.40	0.00	233.84	453.09	686.92	1410.85
100	Reference	Reference	High	pG-h	co2-ref	pE-ref	232.40	495.40	3.08	353.59	172.60	526.19	1257.07
101	FC50	Reference	High	pG-h	co2-ref	pE-ref	224.89	495.40	8.26	327.44	319.11	646.55	1375.10
102	FC100	Reference	High	pG-h	co2-ref	pE-ref	228.53	495.40	12.40	298.40	468.51	766.91	1503.24
103	Reference	Reference	High	pG-h	co2-fix	pE-hS	232.40	495.40	0.70	352.29	163.71	515.99	1244.49
104	FC50	Reference	High	pG-h	co2-fix	pE-hS	224.89	495.40	3.86	306.53	294.09	600.61	1324.76
105	FC100	Reference	High	pG-h	co2-fix	pE-hS	228.53	495.40	7.05	261.30	423.22	684.52	1415.50
106	Reference	Reference	High	pG-h	co2-ref	pE-hS	232.40	495.40	3.61	365.30	172.19	537.50	1268.91
107	FC50	Reference	High	pG-h	co2-ref	pE-hS	224.89	495.40	9.83	331.81	319.84	651.65	1381.77
108	FC100	Reference	High	pG-h	co2-ref	pE-hS	228.53	495.40	15.90	297.90	467.09	764.99	1504.83

9.3 Total Cost for H2Storage Scenario

#	H2Storage	Demand	PV	Gas	CO2	Elec.	Customer Investment				Utility Cost			Total cost
		Scenario	Scenario	Price	Tax	Price	Heating	PV	Inv.	H2Strg.	oper-elec	oper-gas	oper-total	
1	20M-fr02	Reference	Reference	pG-ref	co2-ref	pE-ref	232.40	387.33	0.00	0.29	385.77	143.91	529.68	1149.69
2	500M-fr02	Reference	Reference	pG-ref	co2-ref	pE-ref	232.40	387.33	0.00	7.15	385.77	143.91	529.68	1156.56
3	1G-fr02	Reference	Reference	pG-ref	co2-ref	pE-ref	232.40	387.33	0.00	14.30	385.77	143.91	529.68	1163.71
4	2G-fr02	Reference	Reference	pG-ref	co2-ref	pE-ref	232.40	387.33	0.00	28.60	385.77	143.91	529.68	1178.01
5	10G-fr02	Reference	Reference	pG-ref	co2-ref	pE-ref	232.40	387.33	0.00	143.00	385.77	143.91	529.68	1292.41
6	20M-fr02	Reference	Reference	pG-ref	co2-ref	pE-hS	232.40	387.33	0.75	0.29	399.99	141.35	541.34	1162.11
7	500M-fr02	Reference	Reference	pG-ref	co2-ref	pE-hS	232.40	387.33	1.19	7.15	400.18	140.61	540.79	1168.86
8	1G-fr02	Reference	Reference	pG-ref	co2-ref	pE-hS	232.40	387.33	1.30	14.30	400.06	140.59	540.65	1175.98
9	2G-fr02	Reference	Reference	pG-ref	co2-ref	pE-hS	232.40	387.33	1.29	28.60	400.04	140.57	540.61	1190.23
10	10G-fr02	Reference	Reference	pG-ref	co2-ref	pE-hS	232.40	387.33	0.89	143.00	400.44	140.45	540.89	1304.50
11	20M-fr1	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	104.09	0.29	539.41	0.00	539.41	1263.51
12	500M-fr1	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	89.90	7.15	526.37	0.00	526.37	1243.14
13	1G-fr1	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	85.58	14.30	526.63	0.00	526.63	1246.24
14	2G-fr1	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	80.15	28.60	526.95	0.00	526.95	1255.42
15	10G-fr1	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	65.65	143.00	524.43	0.00	524.43	1352.81
16	20M-fr02	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	2.08	0.29	396.69	178.95	575.64	1197.74
17	500M-fr02	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	2.22	7.15	397.21	178.25	575.46	1204.55
18	1G-fr02	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	2.31	14.30	397.57	177.76	575.34	1211.67
19	2G-fr02	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	2.41	28.60	397.94	177.24	575.18	1225.92
20	10G-fr02	Reference	Reference	pG-h	co2-ref	pE-ref	232.40	387.33	2.59	143.00	398.89	175.96	574.84	1340.16
21	20M-fr1	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	104.09	0.29	549.70	0.00	549.70	1273.80
22	500M-fr1	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	92.77	7.15	529.84	0.00	529.84	1249.49
23	1G-fr1	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	89.47	14.30	528.66	0.00	528.66	1252.17
24	2G-fr1	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	83.80	28.60	529.02	0.00	529.02	1261.14
25	10G-fr1	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	67.47	143.00	527.18	0.00	527.18	1357.38
26	20M-fr02	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	2.76	0.29	408.25	178.44	586.68	1209.46
27	500M-fr02	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	2.84	7.15	408.40	177.97	586.37	1216.09
28	1G-fr02	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	3.00	14.30	408.59	177.56	586.15	1223.18
29	2G-fr02	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	3.05	28.60	408.84	177.16	586.01	1237.39
30	10G-fr02	Reference	Reference	pG-h	co2-ref	pE-hS	232.40	387.33	3.20	143.00	411.06	174.45	585.50	1351.44
31	20M-fr02	Mild Gas	Reference	pG-ref	co2-ref	pE-ref	215.27	387.33	0.00	0.29	370.61	192.41	563.02	1165.91
32	500M-fr02	Mild Gas	Reference	pG-ref	co2-ref	pE-ref	215.27	387.33	0.00	7.15	370.61	192.41	563.02	1172.77
33	1G-fr02	Mild Gas	Reference	pG-ref	co2-ref	pE-ref	215.27	387.33	0.00	14.30	370.61	192.41	563.02	1179.92
34	2G-fr02	Mild Gas	Reference	pG-ref	co2-ref	pE-ref	215.27	387.33	0.00	28.60	370.61	192.41	563.02	1194.22
35	10G-fr02	Mild Gas	Reference	pG-ref	co2-ref	pE-ref	215.27	387.33	0.00	143.00	370.61	192.41	563.02	1308.62
36	20M-fr02	Mild Gas	Reference	pG-ref	co2-ref	pE-hS	215.27	387.33	1.42	0.29	386.09	187.28	573.37	1177.68
37	500M-fr02	Mild Gas	Reference	pG-ref	co2-ref	pE-hS	215.27	387.33	2.38	7.15	386.44	185.73	572.16	1184.29
38	1G-fr02	Mild Gas	Reference	pG-ref	co2-ref	pE-hS	215.27	387.33	2.52	14.30	386.55	185.43	571.98	1191.40
39	2G-fr02	Mild Gas	Reference	pG-ref	co2-ref	pE-hS	215.27	387.33	2.73	28.60	386.34	185.37	571.71	1205.64
40	10G-fr02	Mild Gas	Reference	pG-ref	co2-ref	pE-hS	215.27	387.33	2.06	143.00	386.82	185.25	572.07	1319.73
41	20M-fr1	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	112.82	0.29	581.60	0.00	581.60	1297.31
42	500M-fr1	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	97.62	7.15	564.15	0.00	564.15	1271.52
43	1G-fr1	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	93.31	14.30	564.20	0.00	564.20	1274.41
44	2G-fr1	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	87.90	28.60	564.54	0.00	564.54	1283.64
45	10G-fr1	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	72.25	143.00	560.93	0.00	560.93	1378.79
46	20M-fr02	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	3.45	0.29	388.65	233.63	622.28	1228.62
47	500M-fr02	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	3.60	7.15	388.89	233.16	622.05	1235.40
48	1G-fr02	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	3.70	14.30	389.23	232.69	621.92	1242.52
49	2G-fr02	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	3.84	28.60	389.54	232.18	621.71	1256.76
50	10G-fr02	Mild Gas	Reference	pG-h	co2-ref	pE-ref	215.27	387.33	4.37	143.00	391.24	229.55	620.78	1370.75
51	20M-fr1	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	112.82	0.29	591.83	0.00	591.83	1307.54
52	500M-fr1	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	101.92	7.15	562.19	0.00	562.19	1273.86
53	1G-fr1	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	100.47	14.30	557.63	0.00	557.63	1274.99
54	2G-fr1	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	96.89	28.60	555.13	0.00	555.13	1283.21
55	10G-fr1	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	76.92	143.00	554.75	0.00	554.75	1377.27
56	20M-fr02	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	4.79	0.29	397.96	233.41	631.37	1239.05
57	500M-fr02	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	4.86	7.15	397.84	232.94	630.78	1245.38
58	1G-fr02	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	4.96	14.30	398.14	232.46	630.60	1252.46
59	2G-fr02	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	5.19	28.60	398.24	232.03	630.27	1266.66
60	10G-fr02	Mild Gas	Reference	pG-h	co2-ref	pE-hS	215.27	387.33	5.16	143.00	400.97	228.74	629.71	1380.47
61	20M-fr02	Reference	Moderate	pG-ref	co2-ref	pE-ref	232.40	199.92	0.00	0.29	481.08	143.91	624.99	1057.59
62	500M-fr02	Reference	Moderate	pG-ref	co2-ref	pE-ref	232.40	199.92	0.00	7.15	481.08	143.91	624.99	1064.46
63	1G-fr02	Reference	Moderate	pG-ref	co2-ref	pE-ref	232.40	199.92	0.00	14.30	481.08	143.91	624.99	1071.61
64	2G-fr02	Reference	Moderate	pG-ref	co2-ref	pE-ref	232.40	199.92	0.00	28.60	481.08	143.91	624.99	1085.91
65	10G-fr02	Reference	Moderate	pG-ref	co2-ref	pE-ref	232.40	199.92	0.00	143.00	481.08	143.91	624.99	1200.31
66	20M-fr02	Reference	Moderate	pG-ref	co2-ref	pE-hS	232.40	199.92	0.75	0.29	492.37	141.35	633.71	1067.07
67	500M-fr02	Reference	Moderate	pG-ref	co2-ref	pE-hS	232.40	199.92	1.19	7.15	492.55	140.61	633.17	1073.82

Continued on next page

#	H2Storage	Demand	PV	Gas	CO2	Elec.	Customer Investment		Utility Cost					Total cost
		Scenario	Scenario	Price	Tax	Price	Heating	PV	Inv.	H2Strg.	oper-elec	oper-gas	oper-total	
68	1G-fr02	Reference	Moderate	pG-ref	co2-ref	pE-hS	232.40	199.92	1.30	14.30	492.43	140.59	633.02	1080.94
69	2G-fr02	Reference	Moderate	pG-ref	co2-ref	pE-hS	232.40	199.92	1.29	28.60	492.41	140.57	632.98	1095.19
70	10G-fr02	Reference	Moderate	pG-ref	co2-ref	pE-hS	232.40	199.92	0.89	143.00	492.81	140.45	633.26	1209.47
71	20M-fr1	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	104.09	0.29	634.72	0.00	634.72	1171.41
72	500M-fr1	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	89.90	7.15	621.68	0.00	621.68	1151.04
73	1G-fr1	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	85.58	14.30	621.94	0.00	621.94	1154.14
74	2G-fr1	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	80.15	28.60	622.26	0.00	622.26	1163.32
75	10G-fr1	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	65.65	143.00	619.74	0.00	619.74	1260.71
76	20M-fr02	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	2.08	0.29	492.00	178.95	670.95	1105.64
77	500M-fr02	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	2.22	7.15	492.52	178.25	670.77	1112.46
78	1G-fr02	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	2.31	14.30	492.88	177.76	670.65	1119.58
79	2G-fr02	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	2.41	28.60	493.25	177.24	670.49	1133.82
80	10G-fr02	Reference	Moderate	pG-h	co2-ref	pE-ref	232.40	199.92	2.59	143.00	494.20	175.96	670.16	1248.06
81	20M-fr1	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	104.09	0.29	642.07	0.00	642.07	1178.76
82	500M-fr1	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	92.77	7.15	622.22	0.00	622.22	1154.46
83	1G-fr1	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	89.47	14.30	621.04	0.00	621.04	1157.13
84	2G-fr1	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	83.80	28.60	621.39	0.00	621.39	1166.11
85	10G-fr1	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	67.47	143.00	619.56	0.00	619.56	1262.35
86	20M-fr02	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	2.76	0.29	500.62	178.44	679.06	1114.42
87	500M-fr02	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	2.84	7.15	500.77	177.97	678.74	1121.05
88	1G-fr02	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	3.00	14.30	500.97	177.56	678.53	1128.15
89	2G-fr02	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	3.05	28.60	501.22	177.16	678.38	1142.36
90	10G-fr02	Reference	Moderate	pG-h	co2-ref	pE-hS	232.40	199.92	3.20	143.00	503.43	174.45	677.88	1256.40
91	20M-fr02	Mild Gas	Moderate	pG-ref	co2-ref	pE-ref	215.27	199.92	0.00	0.29	465.93	192.41	658.33	1073.81
92	500M-fr02	Mild Gas	Moderate	pG-ref	co2-ref	pE-ref	215.27	199.92	0.00	7.15	465.93	192.41	658.33	1080.67
93	1G-fr02	Mild Gas	Moderate	pG-ref	co2-ref	pE-ref	215.27	199.92	0.00	14.30	465.93	192.41	658.33	1087.82
94	2G-fr02	Mild Gas	Moderate	pG-ref	co2-ref	pE-ref	215.27	199.92	0.00	28.60	465.93	192.41	658.33	1102.12
95	10G-fr02	Mild Gas	Moderate	pG-ref	co2-ref	pE-ref	215.27	199.92	0.00	143.00	465.93	192.41	658.33	1216.52
96	20M-fr02	Mild Gas	Moderate	pG-ref	co2-ref	pE-hS	215.27	199.92	1.42	0.29	478.46	187.28	665.74	1082.64
97	500M-fr02	Mild Gas	Moderate	pG-ref	co2-ref	pE-hS	215.27	199.92	2.38	7.15	478.81	185.73	664.54	1089.25
98	1G-fr02	Mild Gas	Moderate	pG-ref	co2-ref	pE-hS	215.27	199.92	2.52	14.30	478.92	185.43	664.36	1096.36
99	2G-fr02	Mild Gas	Moderate	pG-ref	co2-ref	pE-hS	215.27	199.92	2.73	28.60	478.72	185.37	664.09	1110.60
100	10G-fr02	Mild Gas	Moderate	pG-ref	co2-ref	pE-hS	215.27	199.92	2.06	143.00	479.19	185.25	664.44	1224.69
101	20M-fr1	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	112.82	0.29	676.91	0.00	676.91	1205.21
102	500M-fr1	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	97.62	7.15	659.46	0.00	659.46	1179.42
103	1G-fr1	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	93.31	14.30	659.51	0.00	659.51	1182.31
104	2G-fr1	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	87.90	28.60	659.85	0.00	659.85	1191.54
105	10G-fr1	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	72.25	143.00	656.25	0.00	656.25	1286.69
106	20M-fr02	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	3.45	0.29	483.97	233.63	717.59	1136.52
107	500M-fr02	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	3.60	7.15	484.20	233.16	717.37	1143.30
108	1G-fr02	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	3.70	14.30	484.54	232.69	717.23	1150.42
109	2G-fr02	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	3.84	28.60	484.85	232.18	717.03	1164.66
110	10G-fr02	Mild Gas	Moderate	pG-h	co2-ref	pE-ref	215.27	199.92	4.37	143.00	486.55	229.55	716.10	1278.65
111	20M-fr1	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	112.82	0.29	684.20	0.00	684.20	1212.50
112	500M-fr1	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	101.92	7.15	654.57	0.00	654.57	1178.83
113	1G-fr1	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	100.47	14.30	650.00	0.00	650.00	1179.96
114	2G-fr1	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	96.89	28.60	647.50	0.00	647.50	1188.18
115	10G-fr1	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	76.92	143.00	647.13	0.00	647.13	1282.24
116	20M-fr02	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	4.79	0.29	490.34	233.41	723.75	1144.01
117	500M-fr02	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	4.86	7.15	490.21	232.94	723.15	1150.35
118	1G-fr02	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	4.96	14.30	490.51	232.46	722.97	1157.43
119	2G-fr02	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	5.19	28.60	490.61	232.03	722.64	1171.62
120	10G-fr02	Mild Gas	Moderate	pG-h	co2-ref	pE-hS	215.27	199.92	5.15	143.00	493.33	228.75	722.09	1285.43