National Technical University of Athens

Semi-centralised production of renewable hydrogen through Power-to-Hydrogen technology in an industrial region for use in heavy industry and warehouses

DIPLOMA THESIS

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Περίληψη

Το υδρογόνο χρησιμοποιείται ως α’ ύλη σε πολλές βιομηχανικές διεργασίες, για περισσότερο από έναν αιώνα. Η χρήση του τα τελευταία χρόνια, έχει επεκταθεί και σε άλλους τομείς της ανθρώπινης δραστηριότητας και αποτελεί πλέον μέσο αποθήκευσης ενέργειας και καύσιμη ύλη στον τομέα των μεταφορών. Ο λόγος για την επέκταση της χρήσης του υδρογόνου είναι η δυνατότητα που προσφέρει για την μείωση των εκπομπών του διοξειδίου του άνθρακα, εάν παραχθεί με την χρήση ανανεώσιμων πηγών ενέργειας. Ωστόσο, το μεγαλύτερο μέρος της παραγόμενης παγκόσμιας ποσότητας υδρογόνου προέρχεται από την αναμόρφωση φυσικού αερίου, και επομένως συνοδεύεται από έκλυση ποσότητας διοξειδίου του άνθρακα.

Το υδρογόνο κατηγοριοποιείται με βάση το αποτύπωμα του σε διοξείδιο του άνθρακα, με βάση το πρόγραμμα CertifHy του ευρωπαικού οργανισμού FCH-JU (Fuel Cells and Hydrogen Joint Undertaking) με βάση το οποίο, υδρογόνο που παράχθηκε με έκλυση τουλάχιστον 60% λιγότερου διοξειδίου του άνθρακα σε σχέση με την διαδικασία αναμόρφωσης φυσικού αερίου θεωρείται υδρογόνο «χαμηλού άνθρακα» (low-carbon). Εάν η ενέργεια που χρησιμοποιείται προέρχεται από πηγές ανανεώσιμης ενέργειας, το παραγόμενο υδρογόνο, χαρακτηρίζεται περαιτέρω, ως «ανανεώσιμο» ή «πράσινο» υδρογόνο.

Παρόλο που τα περιβαλλοντολογικά οφέλη του ανανεώσιμου υδρογόνου είναι εμφανή, η παραγωγή του είναι προς το παρών οικονομικά ασύμφορή. Οι εμπορικά διαθέσιμες διεργασίες που μπορούν να παράγουν πράσινο υδρογόνο αυτή την στιγμή, είναι οι εξής:

- Ηλεκτρόλυση νερού, χρησιμοποιώντας ανανεώσιμη ηλεκτρική ενέργεια
- Αναμόρφωση βιο-αερίου

Το κόστος των παραπάνω διεργασιών είναι αρκετά υψηλό, ακόμα και σε περιπτώσεις μεγάλου όγκου παραγωγής όπως στις περιπτώσεις διυλιστηρίων πετρελαίου ή μονάδες παραγωγής αμμωνίας, είτε λόγω ακριβής α’ ύλης είτε χαμηλής απόδοσης της διεργασίας. Επιπλέον η μεταφορά του υδρογόνου από το σημείο παραγωγής στον καταναλωτή, αποτελεί μείζων παράγοντα στην αύξηση του τελικής τιμής. Η μεγάλη διαφορά στο κόστος του υδρογόνου, έχει αποτελέσει ανασταλτικό παράγονται στην υιοθέτηση του από την βιομηχανία.

Παρόμοια, παρόλη την πρόσφατη εισαγωγή των Ηλεκτρικών Αυτοκινήτων Κυψελών Καυσίμου (Fuel Cell Electric Vehicles - FCEVs) στην αγορά, το υψηλό κόστος του ανανεώσιμου υδρογόνου, η έλλειψη υποδομών ανεφοδιασμού αλλά και του κόστος απόκτησης του αυτοκινήτου, έχουν εμποδίσει την εξάπλωση αυτών των οχημάτων τόσο στους ιδιώτες, αλλά και τις επιχειρήσεις που χρησιμοποιούν ελαφρά και βαρέα οχήματα.

Ως λύση στα παραπάνω προβλήματα, στην παρούσα εργασία, εξετάζεται μία νέα προσέγγιση: η ταυτόχρονη υιοθέτηση του πράσινου υδρογόνου, από ένα σύμπλεγμα διαφορετικών επιχειρήσεων στην ίδια περιοχή, με την δομή της ημι-κεντρικής (ή ημι-αποκεντρωμένης) παραγωγής (semi centralised). Ταυτόχρονα, γίνεται σύγκριση με δύο ακόμα σενάρια για το ίδιο σύστημα: της πλήρους κεντρικής παραγωγής (centralised)και αποκεντρωμένης παραγωγής (decentralized) υδρογόνου.

Διεργασίες παραγωγής υδρογόνου και σχετικές εκπομπές διοξειδίου του άνθρακα

Υπάρχουν δύο διαφορετικοί μέθοδοι για την παραγωγή υδρογόνου:

- Αναμόρφωση αέριου υδρογονάνθρακα. Το αέριο μπορεί να αποτελείται από φυσικό αέριο, βιο-αέριο (π.χ. μεθάνιο από απόβλητα) ή άεριο σύνθεσης (μίγμα H/CO) που προήλθε από την αεριοποίηση στερεών καυσίμων (π.χ. λιγνίτη)
- Μετατροπή ηλεκτρικής ενέργειας σε υδρογόνο (Power-to-Hydrogen – P2H), όπως η διεργασία της ηλεκτρόλυσης του νερού.

Με εξαίρεση την περίπτωση της αναμόρφωση βιο-αερίου, οι λοιπές διεργασίες αναμόρφωσης, οδηγούν στην έκλυση μεγάλων ποσοτήτων διοξειδίου του άνθρακα στην ατμόσφαιρα, εφόσον δεν συνδυάζονται με την αποθήκευση του παραγόμενου διοξειδίου (Carbon Capture and Storage – CCS). Αντίθετα, η ηλεκτρόλυση του νερού δεν εκλύει κανέναν αέριο ρύπο, ενώ αν η παρεχόμενη ηλεκτρική ενέργεια προέρχεται από ανανεώσιμες πηγές, τότε οι συνολικοί ρύποι του παραγόμενου υδρογόνου είναι εξαιρετικά χαμηλοί.

Η παραγωγή υδρογόνου με ηλεκτρόλυση με την χρήση αιολικής ενέργειας, μπορεί να αποδώσει υδρογόνο, με κατά μέσο όρο, 8 φορές λιγότερο εκλυόμενο διοξείδιο του άνθρακα σε σχέση με την αναμόρφωση φυσικού αερίου.

Οι κυρίαρχες τεχνολογίες ηλεκτρόλυσης που είναι εμπορικά διαθέσιμες αύτη την στιγμή είναι δύο:

- Αλκαλικής ηλεκτρόλυσης (alkaline electrolysis), όπου οι συσκευές χρησιμοποιούν ένα αλκαλικό διάλυμα μεταξύ των ηλεκτριδίων
- Πολυμερικής μεμβράνης (polymer exchange membrane), όπου στην θέση του αλκαλικού διαλύματος βρίσκεται μια μεμβράνη από πολυμερές, διαμέσου της οποίας γίνεται η ανταλλαγή ιόντων

Οι εμπορικά διαθέσιμες συσκευές αλκαλικού τύπου έχουν αποδόσεις μεταξύ 52 και 68%. Λειτουργούν σε χαμηλές πιέσεις, με αποτέλεσμα την ανάγκη για μεγαλύτερη μηχανική συμπίεση του παραγόμενου υδρογόνου και λειτουργούν αποδοτικότερα σε σταθερές συνθήκες, κοντά στην ονομαστική τους ισχύ. Κοστίζουν εώς 1200 €/kW.

Οι συσκευές τύπου PEM, έχουν τυπικές αποδόσεις μεταξύ 39 και 66%, λειτουργούν σε αρκετά μεγαλύτερες πιέσεις, μπορούν να λειτουργήσουν αποδοτικά ακόμα και στο 10% της ονομαστικής ισχύος τους, καθιστώντας αυτού του τύπου τις συσκευές ιδανικές για απόκριση σε δυναμικά ηλεκτρικά φορτία, ώστε να εκμεταλλεύονται τυχόν χαμηλές τιμές ηλεκτρική ενέργειας μέσα στην μέρα. Ωστόσο, το κόστος τους κυμαίνεται στα 1860 με 2320 €/kW.

Το κόστος του υδρογόνου μέσω ηλεκτρόλυσης, κυμαίνεται μεταξύ 3.7 και 8.6 €/kg, ανάλογα την χώρα (και επομένως το κόστος της ηλεκτρικής ενέργειας) και τον τρόπο λειτουργίας της μονάδας ηλεκτρόλυσης (π.χ. δυναμική απόκριση). Σε αντίθεση το κόστος του υδρογόνου από αναμόρφωση φυσικού αερίου, βρίσκεται στο 1.8 €/kg. Ως αποτέλεσμα, το κόστος χρήσης ανανεώσιμου υδρογόνου, ειδικά στις βιομηχανίες είναι απαγορευτικό.

Χρήση της τεχνολογίας P2H σε βιομηχανικές περιοχές

Στην παρούσα εργασία, ως βιομηχανικές περιοχές ορίζονται γεωγραφικές τοποθεσίες στις οποιές υπάρχει μεγάλη πυκνότητα βιομηχανίων, εταιρειών παροχής υπηρεσιών logistics (αποθήκευση και διανομή εμπορευμάτων), διυλιστηρίων κ.α., και βρίσκονται πέριξ κάποιου μεγάλου λιμανιού. Οι περιοχή αυτές, δεν ταυτίζονται αναγκαστικά με τις νομοθετικά ορισμένες «Βιομηχανικές Περιοχές» (Βι.Πε). Επομένως ο όρος “βιομηχανική περιοχή”, θα χρησιμοποιείται στην εργασία αυτή για να περιγράψει αυθαίρετα ορισμένες περιοχές στις οποίες οι παραπάνω τύποι επιχειρήσεων βρίσκονται σε σχετική μικρή απόσταση μεταξύ τους. Παράδειγμα τέτοιας περιοχής, και έμπνευση για το συγκεκριμένο μοντέλο, αποτελεί η περιοχή που περιλαμβάνει την Ελευσίνα, Μαγούλα και Ασπροπύργο. Εντός της περιοχής αυτής, βρίσκεται το 60% της ελληνικής δυναμικότητας logistics. Επιπλέον η περιοχή περιλαμβάνει δύο διυλιστήρια των Ελληνικών Πετρελαίων, ναυπηγεία, ένα αεροδρόμιο, βιομηχανίες παραγωγής βαφών, μονωτικών υλικών κ.α. Αντίστοιχες περιοχές απαντώνται σε μεγάλα λιμάνια σε όλη την Ευρώπη, όπως η Αμβέρσα, το Αμβούργο ή το Ρότερνταμ.

Το υδρογόνο σε αυτές τις επιχειρήσεις μπορεί να χρησιμοποιηθεί σαν α’ ύλη σε διεργασίες, όπως στις περιπτώσεις των διυλιστηρίων ή βιομηχανίες γυαλιο. Εναλλακτικά, ως καύσιμο σε ηλεκτρικά ανυψωτικά μηχανήματα, που έχουν αντικαταστήσει τις μπαταρίες τους με κυψέλες καυσίμου, είτε σε ελαφρά ή βαρέα φορτηγά που χρησιμοποιούν κυψέλλες καυσίμου.

Το σύστημα

Το σύστημα το οποίο θα εξετασθεί αποτελείται από 5 διαφορετικές επιχειρήσεις και αποτελούν αντιπροσωπευτικό παράδειγμα πολλών βιομηχανικών περιοχών στην Ευρώπη. Συγκεκριμένα, αποτελείται από ένα διυλιστήριο πετρελαίου, δυο βιομηχανίες, μία παραγωγής ατσαλιού και μία γυαλιού, και δύο επιχείρησες παροχής υπηρεσιών logistics. Μία από αυτές διαχειρίζεται αποθήκη και ένα στόλο ανυψωτικών μηχανημάτων και μία ένα στόλο από επαγγελματικά οχήματα, ελαφρού (van) και βαρέου τύπου (φορτηγά).

Στο σύστημα αυτό, το διυλιστήριο πετρελαίου αποτελεί τον παραγωγό του υδρογόνου και ταυτόχρονα καταναλωτή του, ενώ οι λοιπές επιχειρήσεις είναι μόνο καταναλωτές. Οι ανάγκες κάθε επιχείρησης σε υδρογόνο, προέκυψαν ύστερα από βιβλιογραφική έρευνα, ερωτηματολόγια που δόθηκαν σε εταιρείες logistics στην περιοχή της Ελευσίνας και συνομιλίες με υπαλλήλους.

Το διυλιστήριο του συστήματος, έχει μοντελοποιηθεί με βάση το διυλιστήριο των ΕΛΠΕ στον Ασπρόπυργο, με δυναμικότητα 100 χιλιάδων βαρελιών ημερησίως. Μία τέτοια μονάδα, έχει μία μέση κατανάλωση 388 τόνων ανα ημέρα, η οποία καλύπτεται κυρίως από την μονάδα αναμόρφωσης φυσικού αερίου εντός του διυλησηριού, και από το υδρογόνου που παράγεται ως παραπροιόν από διάφορες διεργασίες.

Μία τυπική μονάδα παραγωγής γυαλιού, χρειάζεται 300 kg υδρογόνου ανα ημέρα και επομένως η μονάδα του μοντέλου σχεδιάστηκε με αυτές τις αναγκες. Τα εργοστάσια παραγωγής ατσαλιού, εμφανίζουν μεγάλες διακυμάνσεις στις δυναμικότητες τους, και έχουν ανάγκες σε υδρογόνου που κυμαίνονται από 100 kg εως 2,000 kg ανα ημέρα. Στη παρούσα μελέτη χρησιμοποιήθηκε ο μέσος, δηλαδή μία μονάδα με ανάγκες 1,050 kg υδρογόνου ανα ημέρα.

Για τις εταιρείες logistics, αρχικά υποτίθεται στόλος 10 ανυψωτικών μηχανημάτων που χρησιμοποιούνται όλο το 24ωρο. Κάθε συμβατικό ανυψωτικό μηχάνημα, χρειάζεται 3 μπαταρίες: μία σε χρήση, μία σε φόρτιση και μία η οποία ψύχεται ώστε να είναι έτοιμη για χρήση. Για τους στόλους των οχημάτων, γίνεται η παραδοχή των 25 βαρέων φορτηγών και 15 van, με δρομολογια των 250 km και 100 km ημερησίως.

Με βάση τις χωρητικότητές των μπαταριών των ανυψωτικών μηχανημάτων και των καταναλώσεων σε πετρέλαιο των οχημάτων παράδοσης, υπολογίστηκαν οι ανάγκες των εταιρειών logistics σε 270 kg υδρογόνου για τα ανυψωτικά και 1084 kg για τον στολο των φορτηγών και van.

Οικονομική αξιολόγηση του συστήματος

Για να αξιολογηθούν οικονομικά οι διάφορες εκδοχές του συστήματος, 3 διαφορετικά «σενάρια» κατασκευάστηκαν.

- Βασικό σενάριο: Σε αυτό το αυτή την περίπτωση, οι διάφορες επιχειρήσεις του συστήματος λειτουργούν με συμβατικά μέσα και διεργασίες. Το διυλιστήριο αυξάνει την παραγωγή υδρογόνου του κατά 3.2 τόνους με την προσθήκη νέας μονάδας αναμόρφωσης υδρογόνου. παράγει υδρογόνο με αναμόρφωση φυσικού αερίου, οι βιομηχανίες γυαλιού και ατσαλιού αγοράζουν υδρογόνου που τους παραδίδεται σε αέρια συμπιεσμένη μορφή με βυτία, τα ανυψωτικά λειτουργούν με μπαταρίες και τα οχήματα έχουν συμβατικούς κινητήρες πετρελαίου.

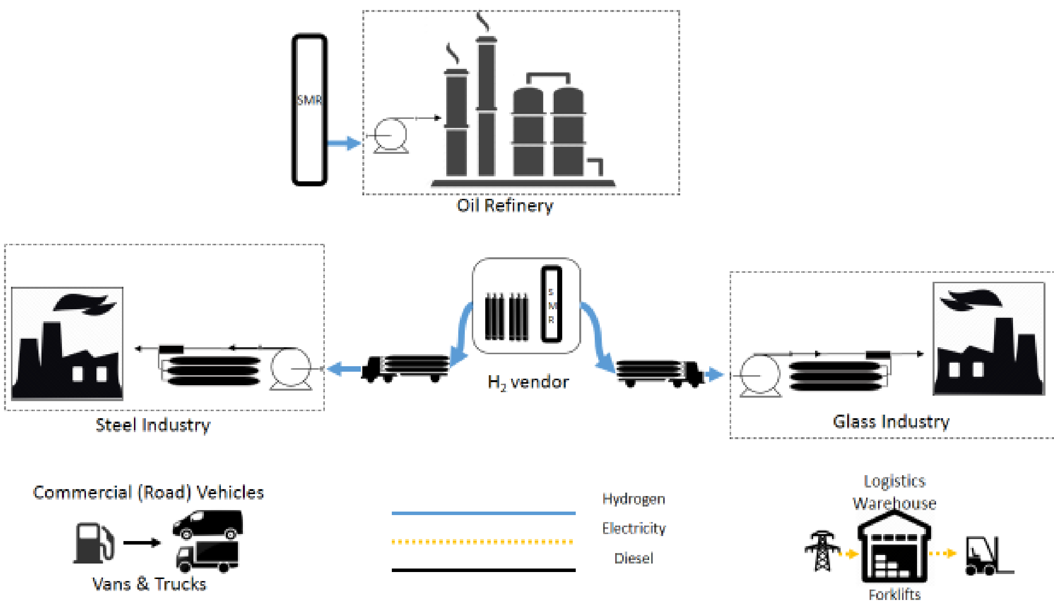


Figure 0-1: Βασικό σενάριο

- Επί τόπου παραγωγή: Σε αυτό το σενάριο, όλες οι επιχειρήσεις παράγουν υδρογόνο για εσωτερική κατανάλωση μέσω συσκευών ηλεκτρόλυσης που έχουν εγκαταστήσει μέσα στις εγκαταστάσεις τους. Το διυλιστήριο, αυξάνει την παραγωγή του σε υδρογόνου με την προσθήκη συσκευής ηλεκτρόλυσης. Τα ανυψωτικά μηχανήματα μετασκευάζονται και λειτουργούν πλέον με κυψέλες καυσίμου υδρογόνου. Η εταιρεία μεταφορών, οχημάτων αντί συμβατικών οχημάτων αγοράζει αντίστοιχα που χρησιμοποιούν κυψέλες καυσίμου. Ο ανεφοδιασμός ανυψωτικών και οχημάτων, λαμβάνει χώρα εντός των εγκαταστάσεων της εταιρείας. Υπολογίζονται τα κόστη για δύο διαφορετικούς τύπους ηλεκτρολυτικών μονάδων, αλκαλικού τύπου (ALK) και πολυμερικής μεμβράνης (PEM)

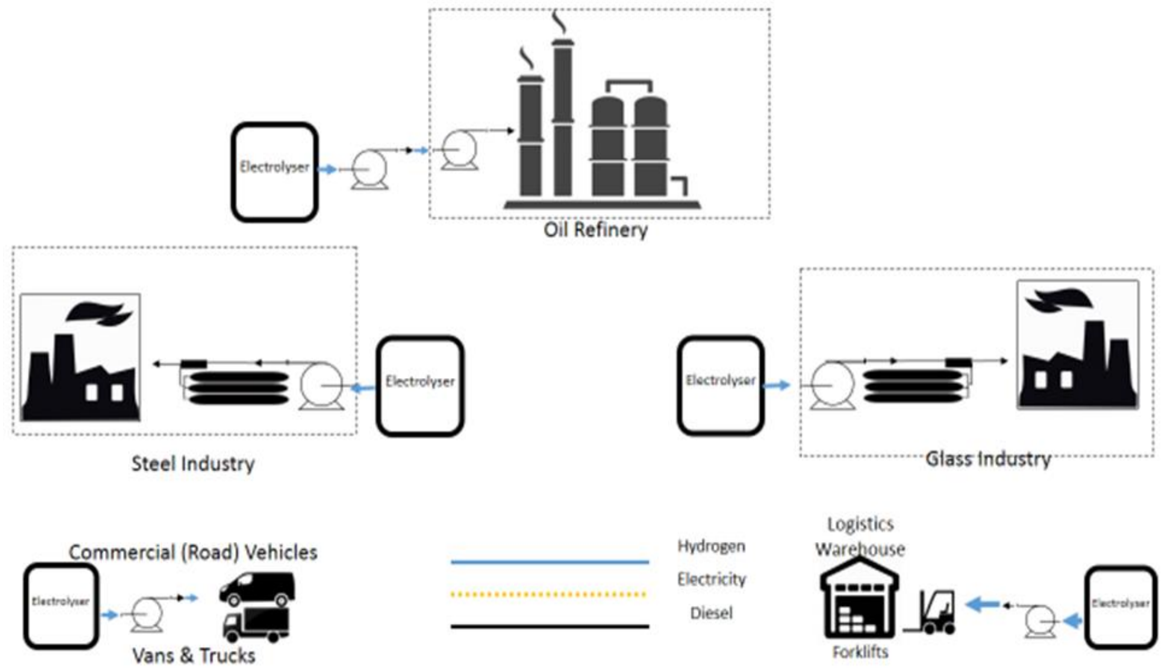
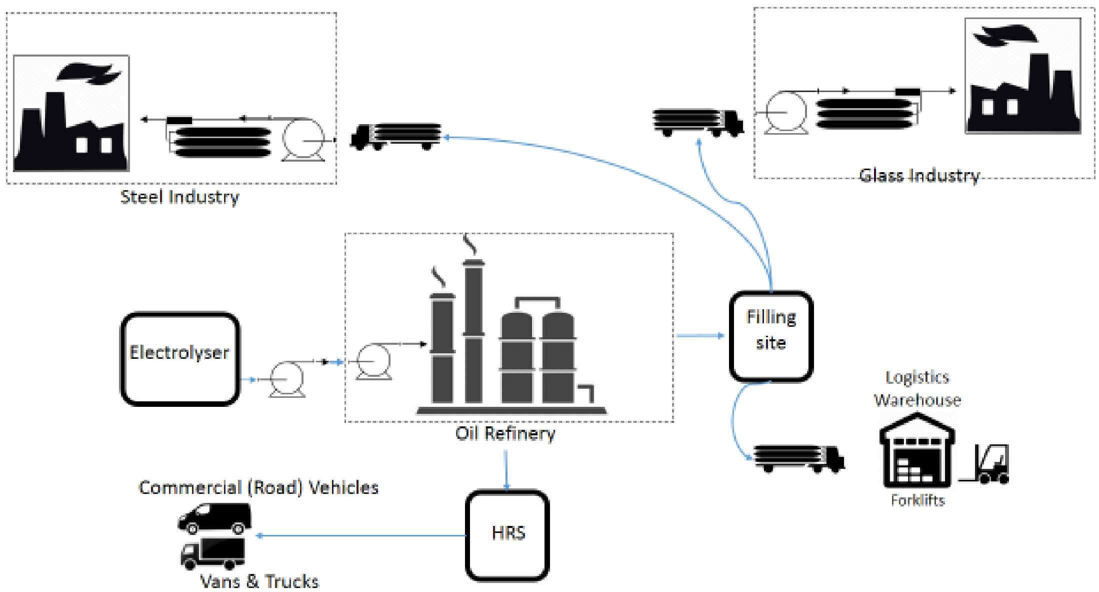


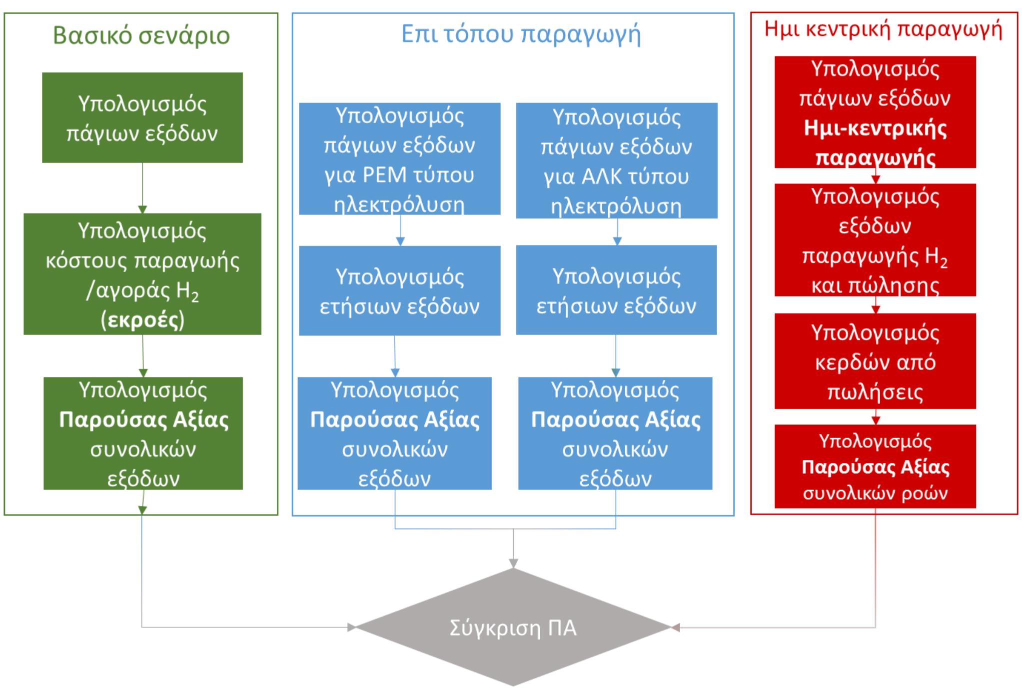
Figure 0-2: Επι τόπου παραγωγή υδρογόνου στο σύστημα

- Ημι-κεντρική παραγωγή: Σε αυτό το σενάριο, η παραγωγή του υδρογόνου γίνεται μόνο στο διυλιστήριο μέσω ηλεκτρόλυσης (αλκαλικού τύπου – ALK). Οι εταιρείες γυαλιού και ατσαλιού, δεν κάνουν καμία επένδυση σε εξοπλισμό και προμηθεύονται υδρογόνο από το διυλιστήριο (παράδοση σε αέρια μορφή, με βυτία του διαλυστηριού). Οι εταιρείες ανυψωτικών και μεταφορών, χρησιμοποιούν και πάλι μηχανήματα και οχήματα με κυψέλες καυσίμου, αλλά δεν παράγουν υδρογόνο. Τα ανυψωτικά εφοδιάζονται και πάλι εντός των εγκαταστάσεων, όμως τα φορτηγά και van ανεφοδιάζονται σε Σταθμό Ανεφοδιασμού Υδρογόνου (ΣΑΥ) που κατασκευάστηκε και λειτουργεί από το διυλιστήριο, πλησίον των εγκαταστάσεων του. Σε αυτό το σενάριο το διυλιστήριο <u>αποκτά επιπλέον εισοδήματα</u>, από την πώληση υδρογόνου στις άλλες επιχειρήσεις του συστήματος



Σχήμα 0-3: Ημι-κεντρική παραγωγή υδρογόνου στο σύστημα

Θεωρήθηκε πως η χρήση ανανεώσιμου υδρογόνου, δεν μεταβάλει τα κέρδη κάθε επιχείρησης. Επομένως για να εξαχθούν συμπεράσματα για την οικονομική βιωσιμότητα κάθε σεναρίου, συγκρίθηκαν μόνο τα συνολικά κόστη των σεναρίων επι τόπιας και ημι-κεντρικής παραγωγής, με το βασικό σενάριο. Χρησιμοποιώντας όλες τις χρηματικές εκροές που προκύπτουν σε βάθος 20ετίας, και την μέθοδο Καθαρής Παρούσας Αξίας (ΚΠΑ), προκύπτουν τα συνολικά κόστη σε κάθε σενάριο. Η μέθοδος της Καθαρής Παρούσας Αξίας, χρησιμοποιεί ένα προεξοφλητικό επιτόκιο στους υπολογισμούς, το οποίο θεωρήθηκε στην παρούσα εργασία, στο 5%.



Σχήμα 0-4: Μεθοδολογία οικονομικής αξιολόγησης

Αποτελέσματα

Το διυλιστήριο του συστήματος παρουσιάζει μικρότερα κόστη σε βάθος 20ετίας σε σχέση με το βασικό σενάριο μόνο στην περίπτωση της ημι-κεντρικής παραγωγής. Η παραγωγή υδρογόνου με ηλεκτρόλυση είναι σημαντικά ακριβότερη από την αναμόρφωση φυσικού αερίου σε όλα τα σενάρια. Όμως στην περίπτωση της ημι-κεντρικής παραγωγής, τα κέρδη από πωλήσεις υδρογόνου στις άλλες εταιρείες του συστήματος φέρουν αρκετά έσοδο για να υπερκαλυφθούν τα επιπλέον έξοδα.

Πίνακας 0-1: Σύγκριση ΚΠΑ όλων των σεναρίων για το διυλιστήριο

Καθαρή Παρούσα αξία κόστους (εκ. €) - διυλιστήριο				
	Βασικό σενάριο	Επι-τόπου παραγωγή		Ημι-κεντρική παραγωγή
		PEM	ALK	ALK
ΚΠΑ	44.9	-77.3	-59.5	38.9
Διαφορά από το βασικό σενάριο	-	72.3 %	32.5%	-13.3 %

Η βιομηχανία γυαλιού παρουσιάζει αυξημένα κόστη για όλα τα σενάρια παραγωγής πράσινου υδρογόνου εξαιτίας των χαμηλών τιμών συμβατικού υδρογόνου. Ακόμα, οι χαμηλές ανάγκες της βιομηχανίας σε υδρογόνου (300 kg/ημέρα), την αποκλείουν από τις οικονομίες κλίμακας, όσο αναφορά τις συσκευές ηλεκτρόλυσης. Αντίθετα, η βιομηχανία ατσαλιού, επιτυγχάνει χαμηλότερα κόστη σε όλα τα σενάριο. Στην επι τόπια παραγωγή, η μεγάλη συσκευή ηλεκτρόλυσης επιτυγχάνει χαμηλό πάγιο κόστος αν kg υδρογόνου. Σε συνδυασμό με τις υψηλές τιμές συμβατικού υδρογόνου, οι ΚΠΑ για όλα τα σενάρια είναι σημαντικά χαμηλότερε του βασικού σεναρίου.

Πίνακας 0-2: Σύγκριση ΚΠΑ όλων των σεναρίων για τη βιομηχανία γυαλιού

Καθαρή Παρούσα αξία κόστους (εκ. €) – βιομηχανία γυαλιού				
	Βασικό σενάριο	Επι-τόπου παραγωγή		Ημι-κεντρική παραγωγή
		PEM	ALK	ALK
ΚΠΑ	9.52	11.07	10.27	10.37
Διαφορά από το βασικό σενάριο	-	20%	11%	12%

Πίνακας 0-3: Σύγκριση ΚΠΑ όλων των σεναρίων για την βιομηχανία ατσαλιού

Καθαρή Παρούσα αξία κόστους (εκ. €) – βιομηχανία ατσαλιού				
	Βασικό σενάριο	Επι-τόπου παραγωγή		Ημι-κεντρική παραγωγή
		PEM	ALK	

ΚΠΑ	41.4	32.08	28.55	36.32
Διαφορά από το βασικό σενάριο	-	-23 %	-31 %	-12 %

Η εταιρεία διαχείρισης ανυψωτικών μηχανημάτων, παρουσιάζει χαμηλότερα κόστη από το βασικό σενάριο σε όλες τις εκδοχές παραγωγής καθαρού υδρογόνου. Αιτία για αυτό, είναι τα αυξημένα κόστη αγοράς μπαταριών, η συχνότητα αντικατάστασης τους και το κόστος σε εργατοώρες ως αποτέλεσμα της χρονοβόρας διαδικασίας αλλαγής τους σε κάθε βάρδια. Η περίπτωση της ημικεντρικής παραγωγής έχει σχεδόν ίδια κόστη σε βάθος χρόνου με αυτά της επι τόπιας παραγωγής (με αλκαλικές συσκευές), χωρίς όμως το ίδιο υψηλό πάγιο κόστος

Πίνακας 0-4: Σύγκριση ΚΠΑ όλων των σεναρίων για την εταιρεία ανυψωτικών

Καθαρή Παρούσα αξία κόστους (εκ. €) – εταιρεία ανυψωτικών				
	Βασικό σενάριο	Επι-τόπου παραγωγή		Ημι-κεντρική παραγωγή
		PEM	ALK	
ΚΠΑ	13.0	12.7	11.4	11.6
Διαφορά από το βασικό σενάριο	-	-2%	-12%	-11%

Το κόστος για τον στόλο οχημάτων μεταφορών, είναι πάντα μεγαλύτερο του βασικού σεναρίου. Αιτία αυτού, τα υψηλά κόστη των οχημάτων κυψελών καυσίμου που αυξάνουν τα πάγια κόστη κατά 200% σε σχέσης με τα συμβατικά οχήματα. Οποιαδήποτε μείωση εξόδων στα σενάρια με τα οχήματα υδρογόνου (πχ. λιγότερα έξοδα συντήρησης), δεν είναι αρκετά να μειώσουν την επίδραση του υπέρογκου αρχικού κεφαλαίου. Ωστόσο, η περίπτωση της ημι-κεντρικής παραγωγής, επιφέρει μία χαμηλή συνολική αύξηση, περίπου 15% επί του βασικού σεναρίου.

Πίνακας 0-5: Σύγκριση ΚΠΑ όλων των σεναρίων για την εταιρεία μεταφορών

Καθαρή Παρούσα αξία κόστους (εκ. €) – εταιρεία ανυψωτικών				
	Βασικό σενάριο	Επι-τόπου παραγωγή		Ημι-κεντρική παραγωγή
		PEM	ALK	
ΚΠΑ	42.6	61.7	55.7	49.0
Διαφορά από το βασικό σενάριο	-	45%	31%	15%

Ανάλυση ευαισθησίας

Στη συνέχεια πραγματοποιήθηκε ανάλυση ευαισθησίας σε διάφορους οικονομικού παράγοντες, όπως η τιμή του ρεύματος, για να μελετηθεί η επίδραση τους στα αποτελέσματα του μοντέλου, καθώς και να οριστεί το «νεκρό σημείο» τους, δηλαδή την τιμή μέγιστη/ελάχιστη τιμή για την οποία ένα σενάριο είναι οικονομικά προτιμότερο από το βασικό

	Παράγοντας	Συμπέρασμα
Διυλιστήριο	Προεξοφλητικό επιτόκιο	Μεγάλη επιρροή στα αποτελέσματα. Χαμηλότερα επιτόκια ευνοούν το μοντέλο της ημι-κεντρικής παραγωγής σε σχεση με το βασικό σενάριο.
	Κόστος συντήρησης μονάδας ηλεκτρόλυσης	Επηρεάζει σημαντικά τα συνολικά κόστη, ωστόσο ακόμα και για ακραίες τιμές, το σενάριο της ημι-κεντρικής παραγωγής υπερισχύει του βασικού.
	Τιμή ηλεκτρικής ενέργειας	Χαμηλότερες τιμές, μειώνουν τα συνολικά κόστη σημαντικά αλλά και την διαφορά μεταξύ ημι-κεντρικής παραγωγής και βασικού σεναρίου. Νεκρό σημείο: • PEM: 12.8 €/MWh • ALK : 30.8 €/MWh • Semi-central : 57.9 €/MWh
	Κόστος ρύπων	Μικρές αλλαγές (±20 €/τόνο) επηρεάζουν σημαντικά τα αποτελέσματα, ωστόσο απαιτούνται τιμές άνω των 100€/τόνο για τα σενάριο επι τόπιας παραγωγής να αποδειχθεί οικονομικότερη του βασικού σεναριού.
	Ημερήσια ζήτηση σε υδρογόνο	Μεγαλύτερη ζήτηση σε υδρογόνο από το διυλιστήριο, μειώνει την διαφορά μεταξύ του βασικού σεναριού κα επι τόπου παραγωγής. Για την ημι-κεντρική παραγωγή, η ημερήσια ζήτηση του διυλιστηρίου πρέπει να αυξάνεται ταυτόχρονα με τις πωλήσεις του για να διατηρηθεί η διαφορά από το βασικό σενάριο σταθερά.
Γυαλί/Ατσάλι	Ημερήσια ζήτηση σε υδρογόνο	Αύξηση της ζήτησης βελτιώνει τα σενάρια επι τόπου παραγωγής.
	Τιμή ηλεκτρικής ενέργειας	Τα σενάρια επι τόπου παραγωγής συμφέρουν μόνο για πολύ χαμηλές τιμές ηλεκτρικής ενέργειας (<28 €/MWh) Το ημι-κεντρικό σενάριο δεν επηρεάζεται.
Ανυψωτι κά	Κόστος κυψελών καυσίμου	Σημαντικός παράγοντας σε όλα τα σενάρια. Τα σενάριο επι τοπου παραγωγής συμφέρουν για τιμές χαμηλότερες των 27.000€ και 18.000 € ανα ανυψωτικό, για αλκαλικού και PEM τύπου ηλεκτρολυση, αντίστοιχα.

	Τιμή ηλεκτρικής ενέργειας	Ο πιο σημαντικός παράγοντας για τα ανυψωτικά μηχανήματα. Νεκρό σημείο στα 70 €/MWh.
Φορτηγά/van	Κόστος οχημάτων	Ο πιο σημαντικός παράγοντας για τα οχήματα μεταφορών. Το κόστος κάθε οχήματος πρέπει να είναι 1.5 φορες το κόστος ενός συμβατικού, ή λιγότερο για να συμφέρει η αγορά τους.
	Τιμή ντήζελ	Μεγαλύτερες τιμές ευνοούν το υδρογόνο. Για τιμές μεγαλύτερες του 1.90 €/L, το σενάριο της ημι-κεντρικης παραγωγής συμφέρει έναντι του βασικού

Συμπεράσματα και προτάσεις

Το μοντέλο της ημι-κεντρικης παραγωγλη υδρογόνου μπορεί να αποδειχθεί επικερδές για κάποιου είδους εταιρείες όπως οι βιομηχανίες ατσαλιού. Ακόμα και στις περιπτώσεις το κόστος είναι μεγαλύτερο της συμβατικής τεχνολογίας, η διαφορά του είναι εντός φυσιολογικών τιμών, λιγότερο 15%. Επιπλέον, το μοντέλο αυτό βοηθά στην μείωση του απαιτούμενου κεφαλαίου από μία εταιρεία που υιοθετεί το ανανεώσιμο υδρογόνο, αφαιρώντας την ανάγκη για την αγορά, εγκατάσταση και συντήρηση συσκευών ηλεκτρόλυσης.

Με βάση τα αποτελέσματα αυτής της εργασίας, προτείνεται η θεσμοθέτηση ειδικού νομοθετικού πλαισίου για την παραγωγή υδρογόνου από ηλεκτρική ενέργεια. Με τον τρόπο αυτό μπορει να μειωθεί το κόστος του ηλεκτρισμού, το οποίο επιβαρύνεται από αρκετούς φόρους και τέλη. Επιπλέον, κατασκευαστές οχημάτων κυψελων καυσίμου, όπως η Toyota ενθαρύνονται να συνεχίζουν την βελτίωση των προιόντων τους ώστε να μειθούν τα κόστη απόκτησης αυτών των οχημάτων. Το αυξημένο αρχικό κεφάλαιο που χρείαζεται μία τετοια επενδυση, είναι όπως φαίνεται από τα αποτελέσματα, ικανό να ανατρέψει οποιαδήποτε οφέλη η τεχνολογία αυτή προσφέρει στους επαγγελματίες που θέλουν να κάνουν χρήση της. Τέλος οι βιομηχανίες, όπως αποδεικνύεται από τα παραπάνω, μπορούν κάτω από τις σωστές συνθήκες να μειώσουν τους ρύπους τους, με μικρό κόστος ή ακόμα και να εξοικονομήσουν χρήματα. Ενθαρρύνονται δε, να δημιουργήσουν πυρήνες ημι-κεντρικής παραγωγής, με τους μεγάλους καταναλωτές υδρογόνου, να αναλαμβάνουν την παραγωγή και διανομή του, καθώς αυτό μπορεί να συνεισφέρει και στην δημιουργία νέων εσόδων.

1 Introduction

Hydrogen has been used as feedstock to many industrial processes for more than a century. It used as from the breaking of complex hydrocarbons, the production of ammonia, electronics, steel and glass manufacturing and in the fats and oils industry. Unfortunately, despite the wide range of use cases, the demand of hydrogen around the globe and the world wide effort for decarbonisation, most of this hydrogen is produced with the use of fossil fuels. The reason behind the lack of clean hydrogen in the industry is the high cost of the different processes that produce renewable hydrogen.

At the same time, its usage has expanded to other sectors and it is now used as an energy storage medium and as a novel fuel for mobility purposes. Hydrogen's potential to decarbonise the transportation sector has brought forward several Zero Emission, Fuel Cell Electric Vehicles. Despite this however, the hydrogen economy has yet to reach the necessary momentum to make a global impact in the energy field. The consumers still have concerns of the lack of infrastructure and investors are concerned by the risk surrounding every new technology.

This thesis, was conducted in collaboration with the Technology Trends Analysis division of Toyota Motor Europe, aims to solve these problems by focusing in the heavy industry and the logistics sector. It aims to analyse industrial clusters, comprised of businesses that could adopt renewable hydrogen, create infrastructure and reduce the costs and risks associated with it. Hopefully, clusters like this, will provide the foundations for a hydrogen economy, that will gain momentum through economies of scale, and will hopefully, take over numerous other sectors of everyday life.

2 Literature review

Although there is still no official standard to distinguish between low emissions and fossil fuel hydrogen, there have been efforts to define what "green" hydrogen is and what is not. Fuel Cells and Hydrogen Joint Undertaking (FCH JU) - a public private partnership between the European Commission, fuel cell and hydrogen industries and the research community - has completed CertifHy [1], a project that developed a framework of the first EU-wide guarantees of origin for green and low-carbon hydrogen. According to CertifHy, if the emissions from the production process (excluding manufacturing of the equipment, storage or transportation) of hydrogen result in less than 60% of the emissions of hydrogen produced from methane reforming, then the resulting hydrogen is defined as low carbon. State-of-the-art steam methane reforming emits 91.0 g_{CO2}/MJ_{H2} and thus any production method (e.g. electrolysis) that results in 36.4 gCO_{2eq}/MJ or less, produces premium hydrogen that could be labeled as low-carbon hydrogen or green hydrogen depending on whether renewable energy is used as an input or not.

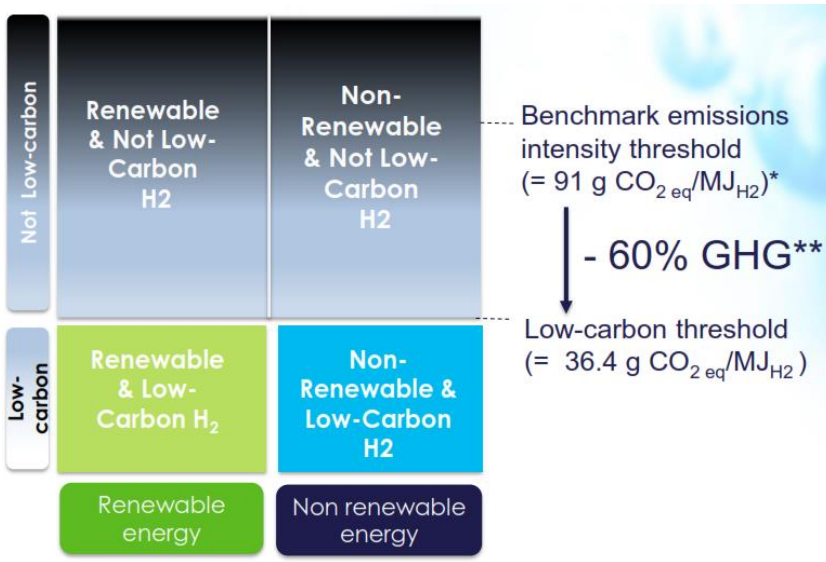


Figure 2-1. CertifHy definition of Low Carbon and Renewable Hydrogen

Although the environmental benefits of green/renewable H2 are clear, its economics appear to be rather challenging. The main challenges are the high electrolysis costs, both capital and operational as well as the small market volume hydrogen as mobility fuel has, which in turn translates into a small revenues for any business venture in this sector.

Currently the only commercialised methods to produce green/renewable hydrogen are the following:

- electrolysis that uses renewable electricity (i.e. electricity from wind or solar energy)
- biogas reforming

Both methods have proven expensive, compared to those using fossil fuels. In addition, producers and distributors of hydrogen have been focusing solely on one application at a time, be it FCEVs or energy storage and therefore excluding additional revenue streams. This has made early business cases unprofitable and has discouraged investments.

Hydrogen has recently been introduced in the transport sector with the first massively produced FCVs available for purchase. Even though the current cost of hydrogen at a Hydrogen Refuelling Station (HRS) does not make the fuel costs of an FCV prohibitively expensive compared to a gasoline vehicle[1], the high capital cost of an FCV, the limited number of models and scarce refuelling infrastructure makes hydrogen mobility a rather difficult choice for a consumer.

In this chapter, the different aspects of hydrogen economy are examined both from a hydrogen production and from a hydrogen application point of view. Higher focus is placed on Power-to-Hydrogen

[1] Currently hydrogen is incentivized, either by governments applying few or no taxes, or by the FCEV dealers that include hydrogen fuel in their FCEV lease plans.

(P2H) production via electrolysis due to its environmental benefits. Then, a rather new use of hydrogen in an industrial region, in the logistics and material handling applications, is investigated thoroughly.

The final aim of this chapter is to review previous studies and existing projects of P2H usage in industrial regions and to highlight the potential of increasing the revenue streams for hydrogen via the use in material handling and other similar uses.

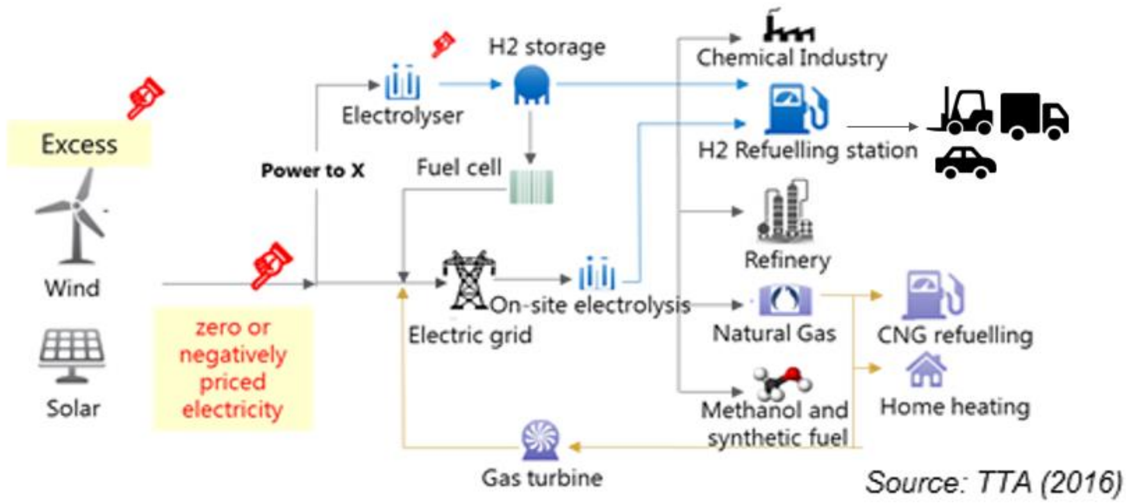


Figure 2-2: Power-to-Hydrogen Economy
(source: Technology Trends Analysis division, Toyota Motor Europe, 2016)

2.1 Hydrogen production methods and respective CO_2 emissions

2.1.1 Overview of CO_2 emissions based on production methods

The usage of H_2 in internal combustion engines (ICE) or fuel cells (FC) produces no CO_2 emissions (although hydrogen ICEs produce some NO_x). However, the production of H_2 is not carbon free. A Life Cycle Analysis variant for road transport fuels is the Well-to-Tank (WTT) analysis. It includes the emissions from the extraction of the primary energy carrier (in this case natural gas) as well as the emissions of producing the fuel (H_2) up to the point of refuelling to a vehicle.

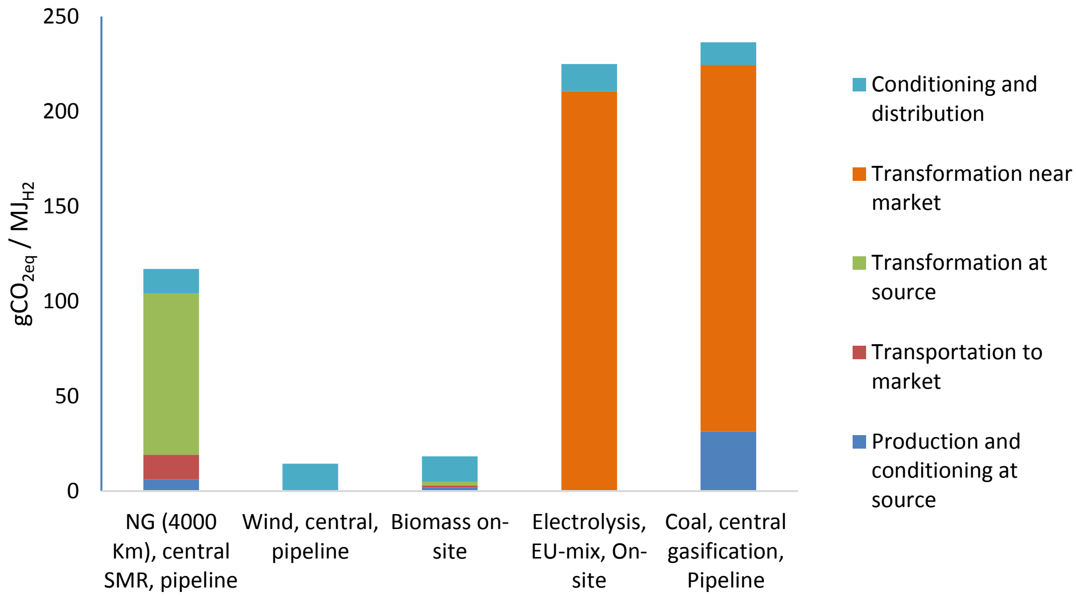


Figure 2-3: Well-to-Tank emissions for different hydrogen production pathways in gCO_{2eq}/MJ_{H2}

Figure 2-3 presents the WTT emissions of different hydrogen production methods and pathways. The pathways are explained below:

- <u>NG (4000km), central SMR, pipeline</u>: Production of hydrogen using natural gas, transported with pipelines 4000km from the production site to a central SMR plant. Hydrogen is also delivered by pipelines. Total emissions 117 $gCO2_{eq}/MJ_{H2}$.
- <u>Wind, central, pipeline</u>: Electrolysis in a central plant using electricity from wind energy. Hydrogen is transported with pipelines. Total emissions 14.5 $gCO2_{eq}/MJ_{H2}$.
- <u>Biomass, on-site</u>: Gasification of biomass on-site of hydrogen usage. Total emissions 18.3 $gCO2_{eq}/MJ_{H2}$.
- <u>Electrolysis EU-mix, on-site</u>: On-site electrolysis using grid electricity. Based on the average EU emissions for electricity production. Total emissions 225 $gCO2_{eq}/MJ_{H2}$.
- <u>Coal, central gasification, pipeline</u>: Gasification of coal at a central plant with pipeline transportation of produced hydrogen. Total emissions 236.4 $gCO2_{eq}/MJ_{H2}$

Power to Hydrogen via Electrolysis

Electrolysis is the process of splitting water into hydrogen and oxygen using electricity that currently produces 4% of the world's hydrogen (65 million tonnes) [2]. Current state of the art systems consume $50kWh/kg_{H2}$, using low current densities, although that can be optimised for lower capital cost, in which case the current density increases [2]. These variations produce a range of different efficiencies, and current commercial applications vary in efficiency usually between 55-75%; however, they can reach up to 85% [3]. These relatively low efficiencies, compared to SMR in combination with low prices of natural gas, render electrolysis economically uncompetitive to more conventional H_2 production methods like SMR or coal gasification [4]. However, electrolysis has the potential to produce carbon free hydrogen if the electricity needed is derived from renewable energy sources like wind or solar. Electrolysers have the potential to be used only during excess renewable electricity is available or during periods of low electricity prices. Unfortunately, however, electrolysers are inherently more efficient at lower loads, and manufacturers have yet to develop products that provide high efficiency across the load curve. [2]

In general, cost reductions are expected in the coming years, since currently the electrolyser market is small and economies of scale in their productions have not been achieved. In addition, manufacturers have limited suppliers and might have to use parts not specifically designed for electrolysers. Therefore, an increase of demand will improve the supply chain and more cost-efficient production methods will be used. The capital expenses (CAPEX) for electrolysis systems do not benefit today from scaling up in the same way that other technologies do (e.g. thermal power plants). An increase to the capacity of the system requires a proportionate increase to the size of the electrolytic cell thus increasing the capital cost of the system.

On the other hand, the operational expenses (OPEX) can be influenced by the system size. OPEX is usually estimated as a percentage of the CAPEX of the system for electrolysers. Although the annual materials expenses will scale up relevant to the capacity of the unit (estimated at around 1.5% of the system's CAPEX), labour costs can be reduced if a business opts for a larger unit, dropping from 5% of the total CAPEX for a 1 MW installation, to 2% for a 10 MW unit [2].

Electrolysers are divided into alkaline, Polymer Exchange Membrane (PEM) and Solid Oxide Electrolysis Cell (SOEC).

<u>Solid Oxide Electrolysis Cell (SOEC)</u>

SOEC electrolysers are the most electrically efficient but the least developed. Developed in the 1980s SOEC electrolysers operate at 800-1000 ^{O}C and promise very high efficiencies. The can reach Faradaic efficiency of 100% and need 2.6 kWh_{el}/Nm^3_{H2} which translates into 28.92 kWh_{el}/kg_{H2} or 86% energy efficiency ($1kg_{H2}$=33.3 kWh) [5]. However these electrolysers are facing certain obstacles including corrosion, sealing, thermal cycling and chrome mitigation [6].

<u>Alkaline electrolysis</u>

Alkaline electrolysis is the predominant type of electrolysis used to date [2, 6, 7]. This type uses an alkaline solution as the electrolyte, usually a concentrated KOH aqueous solution.

The device consists of two compartments housing the anode and the cathode and a diaphragm usually made of asbestos keeping them separate to increase efficiency and safety [7, 8]. At the anode, hydroxide anions (OH^-) are oxidized, resulting in oxygen, water and electrons according to equation (1). At the cathode, protons (H^+) combine with the produced electrons and form H_2, a shown in equation (2). Equation (3)**Error! Reference source not found.** represents the overall reaction taking place inside the cell nd is simply the sum of the half reactions

$$2OH^- \rightarrow H_2O + 2e^- \tag{1}$$

$$\mathrm{H_2O + 2e^- \rightarrow H_2 + 2HO^-} \tag{2}$$

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2 \tag{3}$$

Alkaline electrolysers produce relatively pure hydrogen while having capacities ranging from 0.25 to 760 Nm^3 of H_2/h and 1.8 to 5,300 kW and therefore are suitable for large commercial applications [2]. An alkaline electrolyser requires currently 50-78 kWh_{el}/kg_{H2} (efficiency of 42-66%) although [9] reports as little as 42.2 kWh/kg (78.9%). That range is estimated to be reduced to 48-63 kWh_{el}/kg_{H2} (efficiency of 52-68%) by 2030 according to [2]. Current capital costs range between 1000 and 1200 €/kW with future (2030) prices anywhere between 370 and 800 €/kW [2, 10]. Although they offer the lowest capital costs, due to their electrical efficiency, the electricity costs are the highest, compared to other types of electrolysers [6].

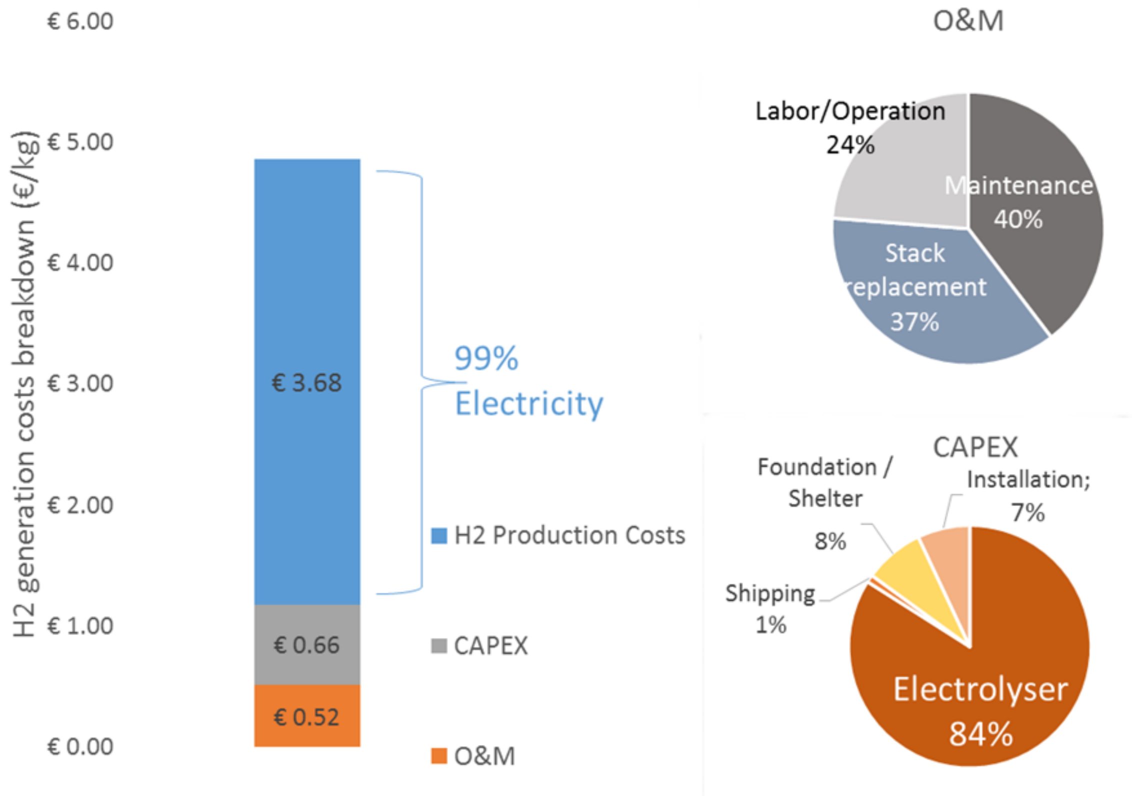


Figure 2-4 shows the costs associated with an alkaline electrolyser of 25 kg/h used at 100% of its capacity [11].

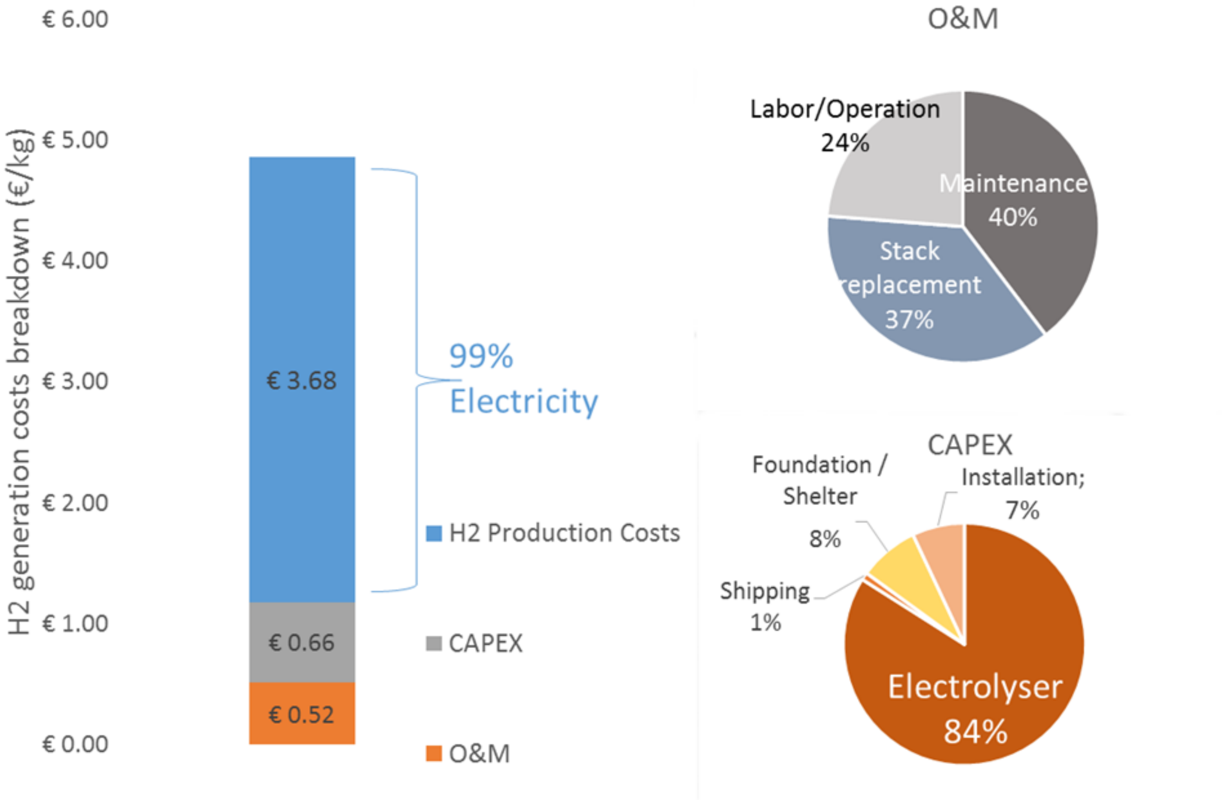


Figure 2-4: Hydrogen generation costs for an alkaline electrolyser (25 kg/h, 100% capacity)

14.Alkaline electrolysers have certain disadvantages: they operate in lower pressures, making the compression of the produced hydrogen necessary and further increasing the production costs. In addition their dynamic operation is limited; [2] reports that alkaline systems can ramp up from part-load to full load with a rate of about 7%/sec. This attribute makes them rather unsuitable for responding to the surpluses of renewable energy in the electricity grid.

2.1.1.1.1 Polymer Exchange Membrane (PEM)

PEM electrolysers offer higher efficiencies and compactness but also cost more than alkaline electrolysers [6, 7]. This type of electrolysers can deliver higher purity hydrogen. Instead of liquid electrolyte in the system a thin polymer membrane is used which broadens the operating power range of the system from 10% to 100% of the nominal power

The stack also operates at higher pressure, thanks to the solid electrolyte (the membrane) and the compact design that offers superior structural properties [7]. Operation of an electrolyser at high pressure lowers the mechanical compression needs after production which can greatly reduce costs, especially in the case that hydrogen is used in Fuel Cell Vehicles (FCVs) that pressures of 350 or 700 bar are necessary.

PEM electricity consumption varies between 50-83 kWh_{el}/kg_{H2} (39-66% efficiency) but that range is expected to be narrowed to 44-53 kWh_{el}/kg_{H2} in 2030 (62-75% efficiency) [2].

The costs of PEM electrolysers are about double of alkaline units at €1860-2320/kW, but for small capacities (less than 100 kW) in some markets they can be competitive. The costs are expected to reach €250-1270/kW by 2030 [2].

Industrial electrolysers have been typically designed to operate at a set load to deliver a continuous stream of hydrogen. However, recent applications of electrolysers such as grid balancing or use of excess renewable energy require the cell to quickly respond to fluctuating power input. PEM units can be readily applied to dynamic operation and stacks have been manufactured that can ramp up their production up to $100\%_{full\ load}$ in less than 1 sec [2] but typical rates are at about $40\%_{full\ load}$/sec.

Table 2-1: Summary of Alkaline and PEM electrolysers specifications

	Capex Costs (€/kW) (current)	Capex 2030 (€/kW)	Efficiency	Kwh/kg H2	$\%_{full\ load}$/sec
Alkaline	1000-1200	370-800	42-66%	50-78	7
PEM	1860-2320	250-1270	39-66%	50-83	40

Costs variations and operating strategies

FCH JU's study [2] reports hydrogen prices for 4 different EU countries and shows the range in hydrogen prices for different electricity prices and operating scenarios. As Figure *2-5* shows there is a great variation in industrial electricity prices mainly due to the difference in network charges. As a result, an electrolyser in the UK is fed with nearly 60% more expensive electricity compared Germany.

This difference causes a large spread in hydrogen prices. Figure *2-6* shows that Germany can achieve much lower prices almost under any operating strategy thanks to low electricity costs. The different strategies represent the way the electrolyser is chosen to be operated. The price minimisation strategy dictates the electrolyser is used when the spot prices of electricity are low while in balancing services scenario, the electrolyser runs all the time unless the network operator requests the system off to balance the demand. For this service, the electrolyser owner is compensated. Only the UK and Germany have published data for balancing services. The Renewable Generator (RG) scenario simulates an electrolyser off-grid, connected to renewable energy production facility, such as a wind park, with a private cable that is also not connected to the grid due to capacity constraints.

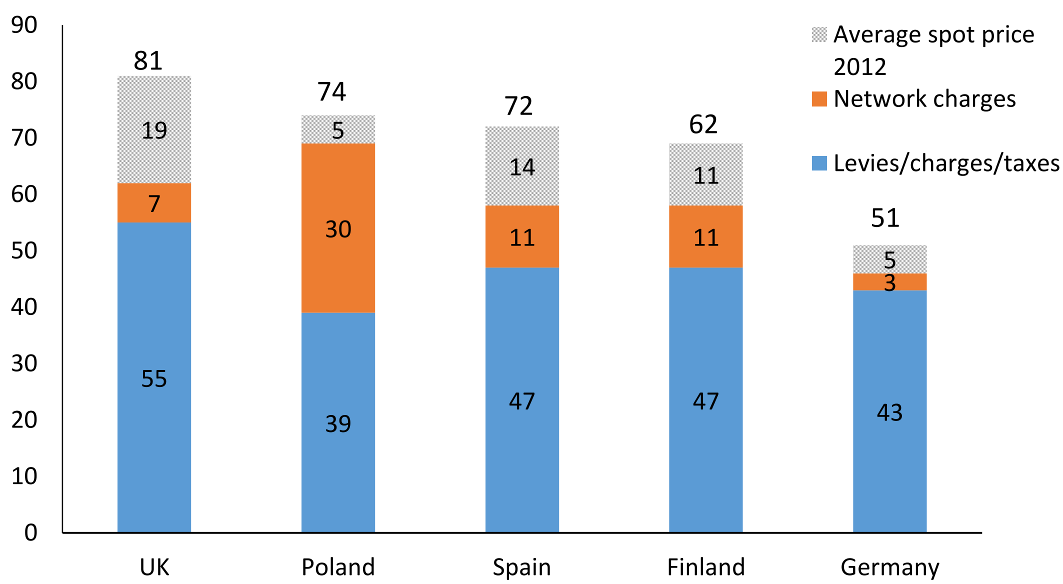


Figure 2-5: Average electricity cost to industrial electrolysers in €/MWh

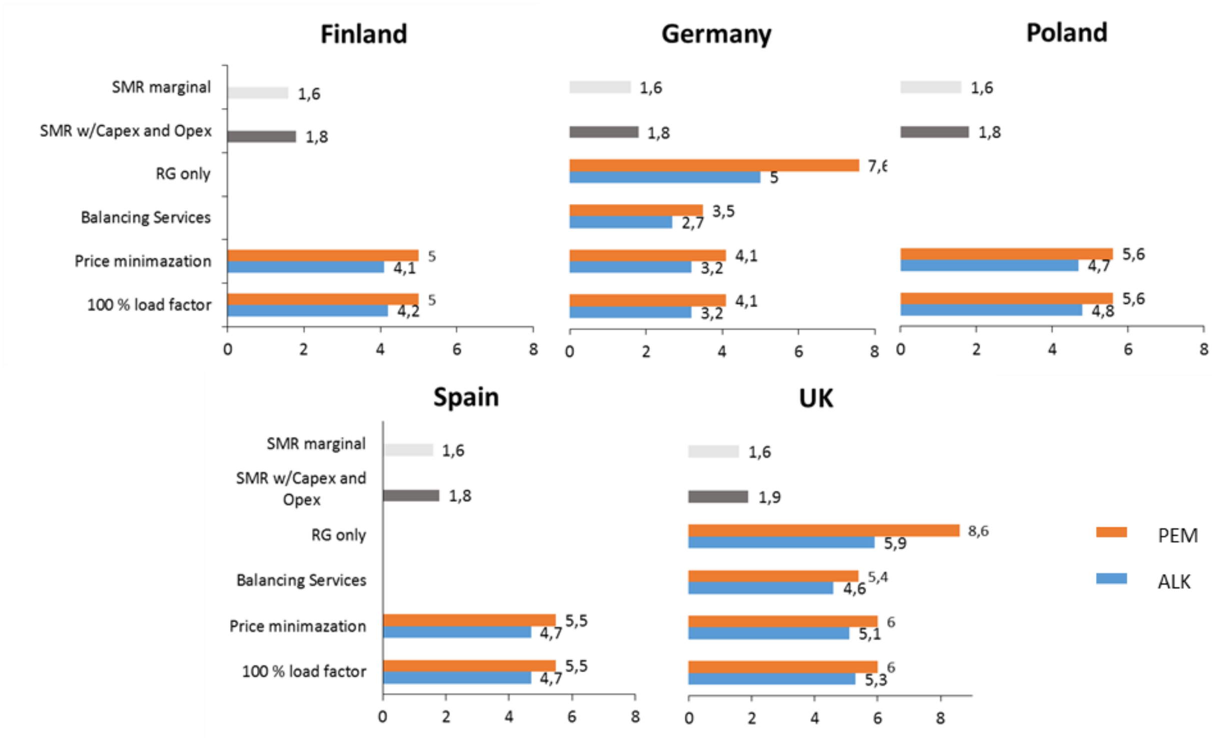


Figure 2-6: Hydrogen costs (2012) for Alkaline and PEM electrolysers in different electricity markets and operation scenarios *[2]*

Figure 2-7: Hydrogen costs (2030) for Alkaline and PEM electrolysers in different electricity markets and operation scenarios *[2]*

The results show that price minimization has barely any effects on the price of hydrogen. Balancing services can provide some significant reduction in the price of hydrogen, but the reduced total production should also be considered, if large supply of hydrogen is needed. Although these results do show significant changes 2030, the RG strategy in the future is rather promising, thanks to cost reductions and electrolyser efficiency improvements.

2.1.2 Challenges of P2H

Electrolysers can produce high quality hydrogen, so P2H is a suitable method to produce hydrogen for any of the applications mentioned above.

However, P2H application faces the obstacle of high capital costs (especially for the electrolyser, see above) that bring the price of electrolytic hydrogen multiple times over that of hydrogen from SMR. In cases such as ammonia production, where hydrogen is produced on site at the plants, the natural gas used constitutes almost 90% of the cost of an already low-cost product (135 €/tonne in the EU, 2012). A more expensive feedstock would have to offset its cost indirectly, for example by reducing the GHG emissions of the plant, and cutting the costs through the European Emissions Trading System.

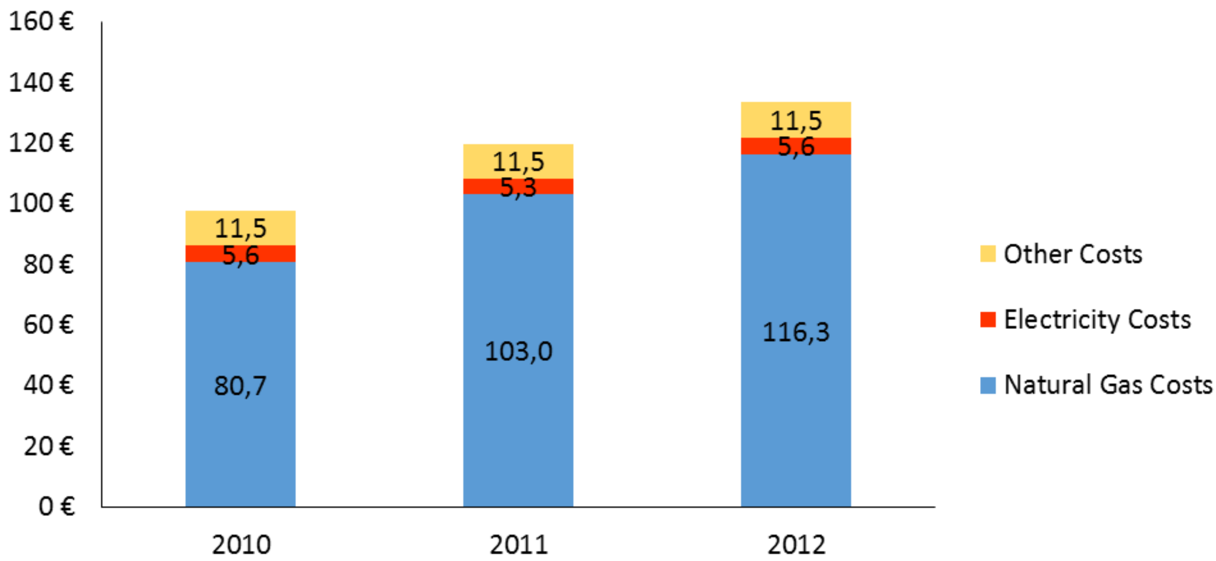


Figure 2-8: Cost breakdown of ammonia in Europe

The same argument can be made for the petrochemical industry as well as any other commodity production plant where the cost of the feedstock comprises most of the OPEX. Electrolytic hydrogen will have trouble competing against its fossil fuel derived variant for feedstock of a hydrocracking process in an oil refinery. But, with the same high price, P2H can compete against the finished product of an oil refinery, gasoline.

As shown below, P2G is a method that enables the storage of excess wind or solar energy through the injection of hydrogen or synthetic natural gas (SNG) in the gas grid. It is obvious that this can lower the GHG emissions of a country, since the hydrogen produced derives from excess renewable energy and therefore is low-carbon. The International Energy Agency has reviewed major studies for the injection of hydrogen to the natural gas grid, and points out that all of them investigate this potential not as the ultimate goal, but as a stepping stone to a hydrogen economy [12].

From a financial perspective, P2G is at a disadvantage because of the low prices of natural gas. The average price of natural gas in the EU 28 between 2012 and 2015 was €9.69/GJ [13]. To match this price, hydrogen would have to cost €1.16/kg[2], which based on the projections in presented above is an over-optimistic target. So if electrolytic hydrogen were to be injected into the NG grid, an expensive product would be used to substitute a cheaper alternative.

It could be argued that this energy would otherwise be lost. However, the produced hydrogen could be introduced in another market, such as the transportation fuel market, to be sold against more expensive alternatives like gasoline or diesel.

In terms of emissions, injection of hydrogen to the gas grid does reduce emissions. However, the same hydrogen has the potential to replace significantly more polluting fuels like gasoline and diesel, which are used in vehicles and are more expensive than natural gas, thus decreasing the price disadvantage.

[2] Cost at the point of the injection

Furthermore, the European Gas Research Group has conducted a study, according to which no significant issues arise to the network from the injection of hydrogen, for concentrations of up to 10% by volume. However, there are certain problems even for low concentration mixtures. More specifically:

1. In the case of underground porous rock storage of natural gas, if hydrogen is present, it can be substrate for sulphate or sulphur reducing bacteria, leading to the formation of H_2S and the plugging of the pores of the reservoir rock. According to the study, a limit to the hydrogen concentration in order to avoid this problem cannot be set yet.
2. Compressed Natural gas (CNG) vehicles have a maximum tolerance to hydrogen. This is caused by the fact that the steel tanks in these vehicles, can be compromised by hydrogen affecting their safety. Therefore, the maximum concentration hydrogen is 2% vol.
3. Gas engines show an increased combustion and end-gas temperature which leads to increased NO_x emissions and sensitivity for engine knock. Even if the engine is fitted with a knock control system, power output is decreased. Hydrogen can also harm the lambda sensor, leading to false oxygen readings with consequences in NO_x emissions and misfire, because of change in the air/fuel ratio of the mixture.
4. Gas turbines have strict limits concentring the presence of hydrogen in the gas mixture. Current limits are below 5%, with the exceptions of some specific turbines that are capable for up to 20% and turbines specifically made for syngas that can handle up to 50% hydrogen.
5. Gas burners in the domestic sector have been tested under the Gas Appliances Directive since the 90's, which uses a mixture with 23% hydrogen for testing. Therefore, in the short term, domestic gas burners are compatible; however there is no data for an extended period of use. [14]

For mobility purposes P2H can be readily used to provide fuel at stations. Taking into account the current hydrogen prices at HRS and the fuel economy of FCEVs, the cost per km is similar to gasoline powered ICEVs, at least for the European market.

Commercial vehicles are also a valid business case for P2H. These vehicles will either refuel on-site at the loading or drop-off point, like in the case of a logistics company that operates a fleet of FC LCVs and has on-site production, or at an HRS. Especially for the cases of a 350 bar setup, where the compression costs are significantly reduced, electrolytic hydrogen could be a competitive alternative to gasoline or diesel vehicles. In addition, after recent announcements for the ban of diesel engines in major capitals [15], a Zero Emission Vehicle (ZEV) with high availability (quick refuelling) might even become necessary for a company.

In the case warehouses with MHE and round the clock operation, P2H is probably already a cost efficient solution. It has also been noted [3], that small SMR plants can reach up to $50/GJ$_{H2}$ or 6€/kg$_{H2}$ a price that can be matched by electrolysers, especially if excess (e.g. low cost or free) electricity is used. Additionally, even if grid electricity is used, there is always the possibility of future reduction of emissions by installing solar panels on-site. In contrast, the emissions of an SMR plant can only be reduced by CCS, which comes at a significant additional cost and is more suitable for larger plants.

2.2 Use of P2H for Industrial Regions to tackle P2H challenging economics

2.2.1 Definition of an Industrial Region

In this thesis an industrial region refers to a geographical area, populated mostly or entirely by commercial facilities of logistics companies, chemicals production plants or oil refineries. An industrial region, may or may not coincide with an industrial estate (a zone specifically "developed as a site for factories and other industrial businesses" [16]). These industrial regions are often a merge of heavy industry businesses, light industry, business offices and residential areas. Therefore the term "industrial region" will from now on, describe an area with a relatively specific set of businesses in close proximity. These businesses will include first and foremost logistic companies' warehouses and potentially, heavy or light industry sites that use hydrogen as feedstock for different processes such as oil refineries, chemical commodities plants (i.e. ammonia), steel mills etc. Also, buildings that have a needs for high security of supply such as data centres, military compounds or hospitals, might also be included, for their potential use of hydrogen in stationary fuel cells. To clarify the term, the example of Elefsina, is described below.

These characteristics of an industrial region can possibly resolve the economic problems that P2H faces. First of all, the close proximity of those businesses can reduce the cost of transportation of hydrogen. In addition, the regional needs of hydrogen, either in refineries or other manufacturing sites, can increase the revenues of a hydrogen producer.

2.2.2 The case of Elefsina

The region of Elefsina will in this thesis refer to the area that includes the communities of Magoula-Mandra and Aspropirgos. It is a typical example of an industrial region; located next to the port of Elefsina, it is populated mostly by logistic companies. In fact 60% of the Greek logistics capacity is located in this region [17]. In addition, the Hellenic Petroleum refineries, a military airport, shipyards and different manufacturing sites like steel sheet production, paints and insulation materials and other, operate in the area. Residential areas are also present, but these expand around distinct centers and therefore are rather separate from the industrial part of the region.

Figure 2-9 shows the industrial region of Elefsina with most of the logistic companies that operate in the area as well as sites that fit one of the definitions above; heavy industry, manufacturing site, or simply an entity that needs a high security of supply of electricity such as the hospital of Elefsina, are pointed in the map. The polygon covers an area of only 87 km^2.

Figure 2-9: Elefsina's industrial region. Blue denotes logistics companies. Green denotes other businesses with high electricity needs

A similar review of the city of Hamburg has been made. The city is home to Germany's biggest port and coincidentally, has a very active hydrogen economy. A quick review of the businesses around Hamburg's port also reveals a high concentration of logistics companies in close proximity.

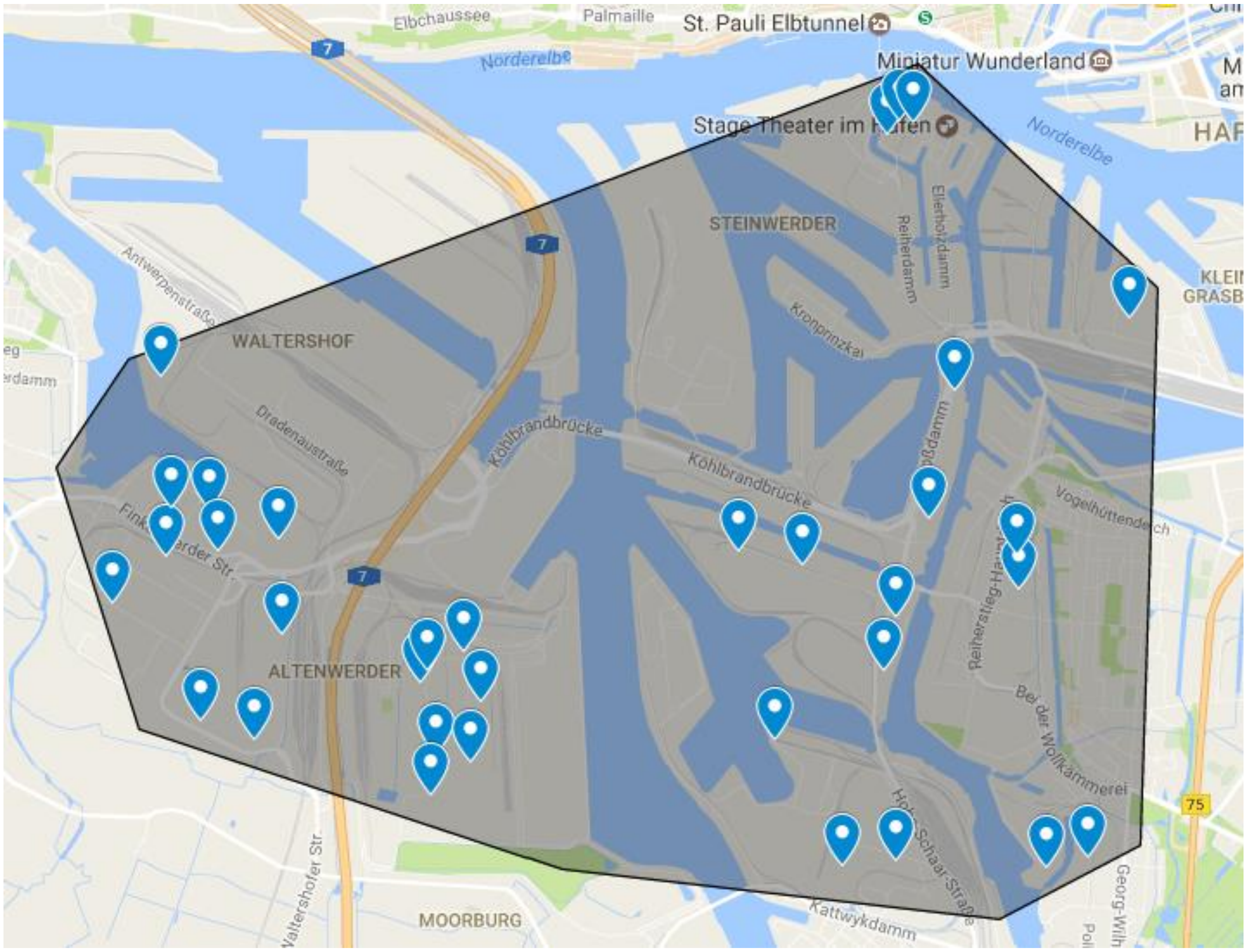


Figure 2-10: Logistics companies in Hamburg's port area, Germany.

2.2.3 Benefits of P2H *for* or *from* an industrial region

As shown above hydrogen from electrolysis, if renewable energy is used, has the potential to significantly lower the emissions of businesses that use it, either as transportation fuel or feedstock or fuel to produce electricity. For this reason, although currently, electrolytic hydrogen produced with grid electricity emits double the carbon per kilogram compared to SMR, it is more appropriate to study the deployment of a P2H production scheme, especially when the future of energy production is taken into account. The EU has a target of 97% renewable energy sources in electricity production by 2050 [18].

After the ratification of the Paris Agreement, countries will need to adopt stricter laws and apply regulations to highly polluting businesses. Refineries, chemicals plants or other factories with high emissions, will need to make their processes "greener" to cope with these stricter emissions laws probably with the higher future costs of these emissions in the carbon market (Emissions Trading System).

Meanwhile hydrogen is already an appealing investment for a warehouse operating a fleet of forklifts and the costs of commercial vehicles are bound to be reduced because of the future mass production of fuel cells, while the emissions regulations are going to be stricter [15]. Especially, if the mainstream fossil fuels (diesel and gasoline) have an increase in price in the future, then the transition to hydrogen powered vehicles seems to be the only way for these businesses that rely on vehicle transportation with high availability.

Furthermore, the hydrogen produced in the industrial region, could very well be used outside of its limits. The adoption of hydrogen in other location such as nearby city centres for the transformation of personal mobility could very well be the one of the impacts since the major problem to date is the high costs of production of green hydrogen.

2.3 H_2 applications at an Industrial Region

2.3.1 Mobility applications

2.3.1.1 Passenger

Fuel Cell Electric Vehicles (FCVs) are electric vehicles whose electric motors are powered by a fuel cell instead of a battery, although in some cases the two power sources can be combined. Currently, only three major automakers massively produce FCVs, although in low numbers compared to ICE vehicles. Honda, Toyota and Hyundai offer the Clarity, Mirai and Tucson ix35 respectively for lease or sale. In all three cases the design of the car is similar, with tanks that store hydrogen at a pressure of 700 bar and a battery that takes advantage of regenerative braking. The electric motor is powered by the fuel cell stack that provides around 100 kW by combining hydrogen stored in the tanks with oxygen from ambient air, producing only water as tailpipe emission. The high pressure hydrogen provides a higher storage capacity with the vehicles mentioned above being able to store up to 5 kg and driving range of over 500 km.

Figure 2-11: Toyota Mirai

Passenger FCV's have 30% less GHG emissions compared to ICEVs even if hydrogen produced by natural gas is used, because of their increased efficiency. If 46% of the hydrogen used is renewable, then emissions can be lowered by as much as 60% [19].

Company cars of businesses in industrial regions could be swapped with FCV as part of the company's strategy to reduce its emissions, since the refuelling infrastructure will be available in the area.

2.3.1.2 Light and medium commercial vehicles (LCVs & MCVs)

Light commercial vehicles (LCV) are vehicles for the carriage of goods that have a maximum mass of 3.5 tonnes. Medium Commercial Vehicles (MCV) are vehicles used for the transportation of goods that weigh under and do not exceed 12 tonnes [20].

Parcel delivery vans are a characteristic example of light or medium commercial vehicles, depending on the size. These vehicles are used during rush hour traffic and thus experience more frequent acceleration and deceleration, causing increased fuel consumption and emissions. Utility vehicles and small vans can spend up to 900 hours per year idling [21]. LCV sales reached 1.368 million vehicles in 2015, the majority (97%) of which were equipped with diesel engines, followed by gasoline (2%) and natural gas (1%) and accounted for 11% of all vehicle sales [22].

Hydrogen powered LCV (FC-LCV) are similar to FCEVs for passenger transport. The same fuel cell-battery-electric motor layout is utilized, however, there have been different operating models. Similarly to the passenger vehicles, H_2 is stored in gaseous form under 700 bar pressure, but unlike their passenger counterpart, some commercial vehicles also store hydrogen under 350 bar [23].

A cost-benefit analysis study [24] compared scenarios where battery EV, internal combustion-battery hybrids, gasoline plug-in hybrids, ethanol plug-in hybrids, hydrogen fuel cell or hydrogen internal combustion hybrid LCVs were adopted in the U.S. Only the hydrogen fuel cell scenario resulted in an 80% CO_2 emissions reduction compared to 1990 levels by 2050. The same study compared the useful energy density of different battery technologies and compressed hydrogen.

Error! Reference source not found. and show that compressed hydrogen systems can provide 300 kWh ore per kilogram or around 120 kWh more per liter compared to batteries. An early demonstration vehicle was showcased in 2008 by PSA and Intelligent Energy. In this project, a BEV version of the Peugeot Partner van, was fitted with a hydrogen PEM fuel cell range extender, making the van effectively an FCV/BEV plug-in hybrid. The BEV version had a range of 78 km. With the addition of the FC range extender the range of the vehicle reached 308 km. The hydrogen tanks had a capacity of 2.7 kg at 700 bar pressure and were mounted on a rack in such a way, that when emptied they could be easily swapped with full tanks, in an effort to tackle the lack of hydrogen refueling infrastructure [25].
Symbio FCell and Renault have developed another fuel cell-battery hybrid by fitting a Renault Kangoo electric van with a hydrogen fuel cell range extender. The van has a 22kWh Li-ion battery that can be charged from the fuel cell, by regenerative braking or by wall plug. Hydrogen tanks can store 1.7 or 2.08 kg in 350 or 700 bar respectively. The company is also testing a 4.5 tonne Renault Maxity with a similar fuel cell-batter setup in partnership with La Poste, a French postal service company [26, 27]

Hyundai revealed in 2016 a hydrogen fuel cell concept variant of their diesel-powered, 3.5 tonnes van, the H350. The FCEV model has a 175 liter hydrogen storage capacity or 7.05 kg at 700 bar combined with a 24 kW battery. The van has a range of 422 kilometers. Refueling of the FC van takes approximately 4 minutes [28, 29].

2.3.1.3 Heavy Commercial Vehicles (HCVs)

This category includes mostly trucks used to haul semi-trailers such as the one in

Figure *2-12***Error! Reference source not found.**. The trailer in this example is called a *semi-trailer* because there is no front axle attached; instead the rear axle of the truck is used in its place [30].

Figure 2-12: Semi-trailer truck

Examples of hydrogen FC HCVs include the 18 tons truck built by a Swiss consortium, including the vehicle manufacturer ESORO. The truck, revealed in November 2016, is used to fulfil the logistics needs of a retail company and it is based on a diesel truck and has a range of 375-400km, thanks to its 7 onboard storage tanks. There the hydrogen is stored at 350bar, reaching a total capacity of 31 kg_{H2} [31]

Figure 2-13: ESOROS' truck hydrogen tanks, located behind the cab (left) and Nikola One (right)

Utah-based startup-up company, Nikola Motors, revealed in December 2016, a FCEV Class 8 "sleeper" truck prototype. Sleeper trucks, have an incorporated in the cab, a small bedroom for the driver for multiple day journeys. The truck boasts a range of 1200 to 1900 km thanks to 100 kg of hydrogen stored in its tanks and a 320 kWh battery. The power output of the electric motors is rated at 1,000 HP and 2700 Nm of torque [32].

2.3.2 Material Handling Equipment - MHE

Material handling equipment is used to move, protect and store materials and products usually in manufacturing plants and warehouses. MHE includes equipment like conveyors, pallet jacks, cranes and forklifts. Forklifts are further categorised in classes [33].

- Class I: Electric Motor Rider Trucks
- Class II: Electric Motor Narrow Aisle Trucks
- Class III: Electric Motor Hand Trucks or Hand/Rider Trucks
- Class IV: Internal Combustion Engine Trucks (Solid/Cushion Tires)
- Class V: Internal Combustion Engine Trucks (Pneumatic Tires)
- Class VI: Electric and Internal Combustion Engine Tractors
- Class VII: Rough Terrain Forklift Trucks

Fuel cell system can readily replace batteries in forklifts, especially in Classes I, II and III and in cases where the equipment needs to operate for more than one shift. In such cases batteries would need to be charged and replaced multiple times a day, while FC powered systems can within minutes refuel [34].

Fuel Cell Logistics Vehicles (FCLV) offer faster refueling times compared to Battery Logistics Vehicles (BLV). Hydrogen tanks can be refilled in 1-5 minutes instead of 8 hours of recharging, 8 hours of cooling and 10-15 minutes of swapping, required for batteries [35]. In addition, hydrogen refueling equipment takes up much less floor space than the recharging infrastructure and the scalability of FCLV is easier, since only additional dispensers are be needed and if necessary an electrolyser upgrade; both of which actions require few additional m^2 of floorspace, which is an important factor for warehouses [11].

In the US alone, Class I forklifts have logged more than 180,000 hours of operation, and more than 25,000 kilograms of hydrogen has been dispensed over nearly 50,000 fuelling events.

The DOE-sponsored deployments are providing even more data to increase our understanding of the performance of fuel cell MHE under real-world operating conditions. As of June 2012, DOE-sponsored warehouse facilities have deployed more than 500 Class I, II, and III material handling units powered with fuel cells. Over more than three years of operation, these fuel cell forklifts have logged 1.25 million hours of operation using 140,000 kg of hydrogen dispensed over almost 200,000 fuelling events.

A National Renewable Energy Laboratory's (NREL) report [34], gathered data from MHE operators from the US market that operated battery or FC equipment to create a cost analysis for these two types. It has to be noted that these figures are for the US market and for warehouses that use the forklifts for approximately 2 shifts per day. Table 2-2 summarizes the data gathered by the NREL.

Table 2-2: Specifications of Class I & II forklifts

Costs	Power unit	
	Battery	Fuel Cell
Operation Days per Year	340	
Operation Hours per Day	2,400	
Average shift per Day	2.25	
Cost of Hydrogen ($/kg)	-	8
Capital Cost of Bare Lift truck	$25,000	
Average Life of Lift Truck (years)	10	
Cost of Batteries (2) / Fuel Cell System	$9,600	$33,000
Federal Tax Credits Available	-	$9,800
Battery / Fuel Cell Systems per Lift	2	1
Battery / fuel Cell System Life (years)	4.4	10

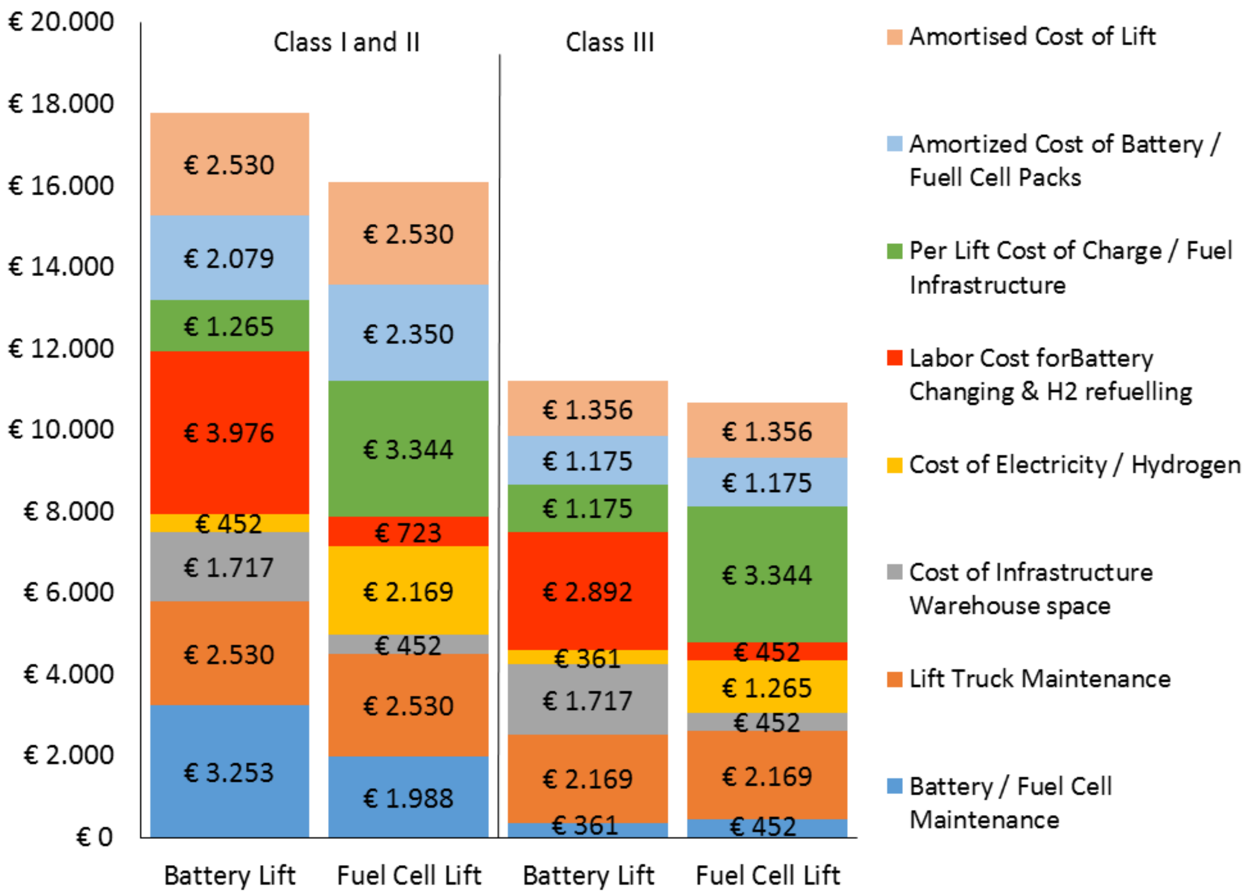


Figure 2-14: Total annual cost of ownership of battery and fuel cell MHE

To cover the needs of a fleet of FC forklifts, on-site hydrogen production using alkaline electrolysis is a cost competitive solution to liquid hydrogen transfer from a central SMR plant, with the additional benefit of increased security of supply [11].

Currently there are several examples of hydrogen MHE equipment. ASKO, the largest food distribution company in Norway, aims to test 10 FC forklifts along its 4 FCEV trucks in 2017-2019. The hydrogen will be produced on-site, using electricity from solar panels. FCH JU's HyLift Demo project tested 10 forklifts in different fleets.

In the U.S. Wal-Mart, a retail company, has a fleet of over 2,200 hydrogen fuel cell forklifts [36]. The postal service company FedEx, has been testing hydrogen fuel cell airport tractors capable of towing up to 18 tons of cargo, at Memphis international airport in Tennessee [37]. BMW manufacturing plant in South Carolina was operating a fleet of 350 hydrogen FC forklifts and tugger trains by the end of 2013. The demand of hydrogen was around 650 kg/day [11]. More than 75 Class I forklifts and 500 Class II and III forklifts have been deployed in Defense Logistics Agency in the US under the sponsorship of the Departments of Energy and Defense [34].

2.3.3 H2 Industrial applications - Use as feedstock

Hydrogen is one of the key starting materials used in the chemical industry. It is a fundamental building block for the manufacture of ammonia, and hence fertilizers, and of methanol, used in the manufacture of many polymers [38].

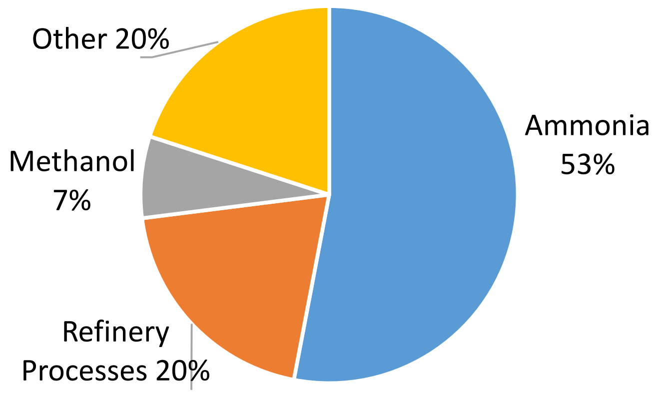


Figure 2-15: Uses of hydrogen

2.3.3.1 Petroleum processing

Hydrogen is used in the petroleum industry in various processes. Hydrocracking, is one of the most common and important processes of a petroleum refinery. It is used to breakdown large hydrocarbon molecules in order to create smaller ones with a higher H/C ratio. Hydroprocessing, uses hydrogen to remove sulfur and nitrogen compounds by turning them into H_2S and NH_3.

2.3.3.2 Petrochemicals

Methanol is produced when hydrogen and carbon monoxide (CO) react under high temperature and pressure over a catalyst. This usage of hydrogen constitutes 7% of the total hydrogen demand. Other petrochemicals that require hydrogen include polypropylene, acetic acid and butanediol. The recycling of plastics also requires hydrogen, in order to break down heavy molecules into lighter ones that can be used to produce again polymers.

2.3.3.3 Ammonia

Most of the global production of hydrogen (53%) is used to produce ammonia. The Haber process is used and nitrogen reacts with hydrogen in high pressures. Ammonia is the main ingredient of fertilizers.

2.3.3.4 Other uses

The food industry uses hydrogen to increase the saturation of fats and oils, in order to increase their melting point and resistance to oxidation [39]. This way they can be preserved for longer periods of time. Liquid hydrogen is used as a propellant in rocket applications. When combined with liquid oxygen it yields the highest amount of energy per unit weight which is needed in the aerospace industry. It is also used in metallurgy for the reduction of nickel and in the electronics industry for the epitaxial growth of silicon. Hydrogen is also used in nuclear reactors, as a scavenger agent, to find any oxygen molecules in the water used in the reactor that can cause corrosion cracking.

2.3.4 Renewable Energy storage applications

In 2014, 14% of Europe’s electricity derived from Renewable Energy Sources (RES), most of which is from wind and a significant part is from solar [40]. These RES however, are intermittent and do not provide a constant electricity production. To increase the penetration of renewables in the electricity mix, their storage is necessary.

Energy storage can yield further benefits. Stored energy adds flexibility to a power grid and gives the advantage to a system with energy storage to smooth the load curve and reduce the usage of peak power plants that have a high marginal cost as well as ensure security of supply since it basically increases the system's generation capacity. This balance of demand and supply has to be adjusted in almost real-time by injecting more power to the grid quasi-instantaneously. Both PEM and alkaline electrolysers and fuel cells have quick response times and can quickly ramp up the production of hydrogen to store energy or turn that hydrogen to electricity to balance the grid.

Hydrogen can serve as a storage medium; excess electricity is fed to an electrolyser and to produce hydrogen thus storing the energy that would otherwise would be lost due to lack of demand or inability of the grid to absorb it. This hydrogen is then re-electrified using stationary fuel cells, used in FCVs or be injected to the natural gas grid in small percentages (up to 10%) [14]. This scheme is known as Power-to-Hydrogen (P2H). This hydrogen can also or be used to produce synthetic natural gas which is then injected to the gas grid (Power-to-Gas - P2G).

Germany is a good example of renewable energy overproduction. The country has tripled its renewable energy electricity production in the last decade [41], and is now facing problems of overproduction. On average in 1.2% of Germany's renewable energy was "wasted" because the demand was not high enough, even though it has a strong electricity export capability [42]. Perhaps for that reason, Germany is home to most of the European P2G project plants.

One of the largest P2G plants in Germany is located in Mainz. The Energiepark Mainz has three PEM electrolysers, with total (peak) capacity of 6 MW, capable of 200 $tonnes_{H2}$/year. It is connected to the electricity grid and an adjacent wind park. The Energiepark produces hydrogen when the wind feed-in is high and it is either loaded to trucks for transportation or directly injected to the natural gas grid, in concentrations of up to 15%. The hydrogen can also be stored; the storage capacity at the park is 1000 kg_{H2} (33 MWh) [43, 44, 45].

The RH_2 WKA project, also in Germany, stores excess wind energy of a 28 turbine wind farm by feeding the excess electricity to a 1 MW electrolyser, capable of producing up to 210 Nm^3_{H2}/h.

Figure 2-16: P2G plants in Europe

The PFI pilot plant in the Pirmasens-Winzeln Energy Park, uses a different way to store wind energy. The plant uses a 2.5 MW electrolyser to produce hydrogen from excess wind energy. This hydrogen is the fed to a bioreactor, along a feedstock of locally produced biogas. As a result, the CO_2 from the biogas is turned into CH_4 resulting in an output gas stream of 95% CH_4. The resulting Synthetic Natural Gas (SNG), meets the natural gas standards, and is injected into the grid. The plant has a goal to produce of 440,000 m^3_{NG}/year. [46]

3 System setup and energy needs

3.1 Introduction

In chapter 3 the target is to select the components of the system that will be analysed. To create a representative model of a common industrial region in Europe, the types of businesses found in such a regions are identified through real world examples and are categorised based on if and how they use hydrogen as well as the way the obtain it. Eventually, a few of them from each category are chosen to be represented in the model and are then assigned a specific size and hydrogen needs, to be used in the simulation process.

3.2 The categories of industries

Industrial areas contain businesses that in this analysis are split into 3 major categories.

The hydrogen consumption of a facility is usually correlated to whether hydrogen is produced in-house through SMR or it is outsourced. For the purposes of this analysis however, the daily needs of a business will not be enough to decide in which category every business should be placed into.

For example, a manufacturing plant that requires 1,000 kg of hydrogen every day, that currently receives delivery through tube trailers cannot be confused with a logistics provider or a bus depot, that after conversion of its fleet, also requires 1,000 kg of hydrogen every day. The compressing, storage and dispensing needs, labour costs and capital investment will be completely different in each case.

1. <u>Hydrogen producers</u>

This category includes industries that require hydrogen in very large quantities and have thus invested in producing hydrogen within their premises using SMR. It includes large chemical companies that produce ammonia or methanol and oil refineries. These plants consume hydrogen in the magnitude of hundreds of tonnes every day [47].

2. <u>Hydrogen consumers</u>

Here industries like electronics, aerospace, edible fats and oils and any other specialty chemicals not included in the first category are included. They require hydrogen in their production processes, although in quantities that justify purchasing hydrogen from third-parties rather than producing it on-site. Manufacturing sites like these consume from a few hundred kilos up to 2 tonnes of hydrogen per day. This category will help define if and when on-site electrolysis or the proposed semi-centralised scheme can be financially attractive.

3. <u>Hydrogen adopters</u>

The third category mostly consists of the logistics sector and transportation companies (vans/trucks), since they do not currently use hydrogen, and their energy needs are covered with electricity (forklifts) and diesel (vans/trucks). The daily consumptions depends on the size and the type of fleet and can range anywhere between a few hundred kilograms (medium sized forklift fleets) to a few tonnes (buses, trucks) [11] [48] [49].

3.3 European industrial areas

In addition to the industrial areas of Elefsina and Hamburg, three more examples are taken under consideration, in order to choose the types of business that best reflect a European industrial area.

Figure 3-1 shows the industrial area around the town of Geel in Belgium. The area is populated by both logistics companies like DHL as well as chemical production plants, like BP's PTA (Purified Terephthalic Acid) and Lubrizol (lubricants and other chemicals) or electronics (semiconductors) manufacturing plants like Henkel electronics and Canberra Semiconductors. As the line indicates the distance between these sites is up to 4.5 km.

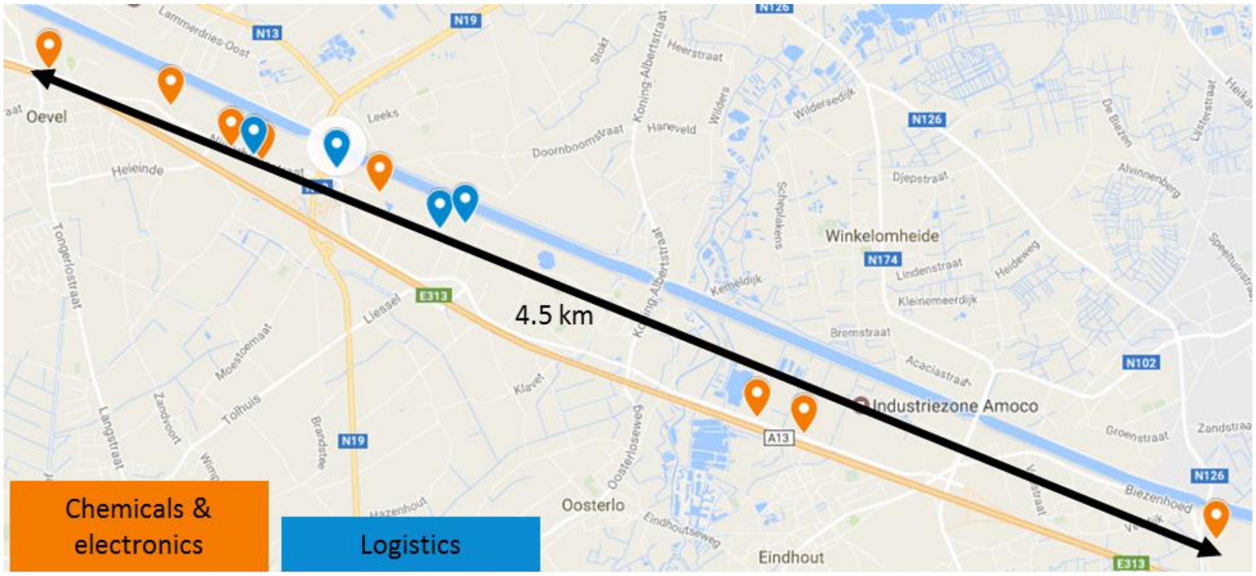


Figure 3-1: The industrial area of Geel, Belgium

Figure 3-2 depicts the area around the port of Antwerp. This area includes all 3 types of businesses: 3 oil refineries, chemicals production sites, an ammonia plant as well as industrial gases producers (including hydrogen) such as Praxair and Air Liquide and logistics providers.

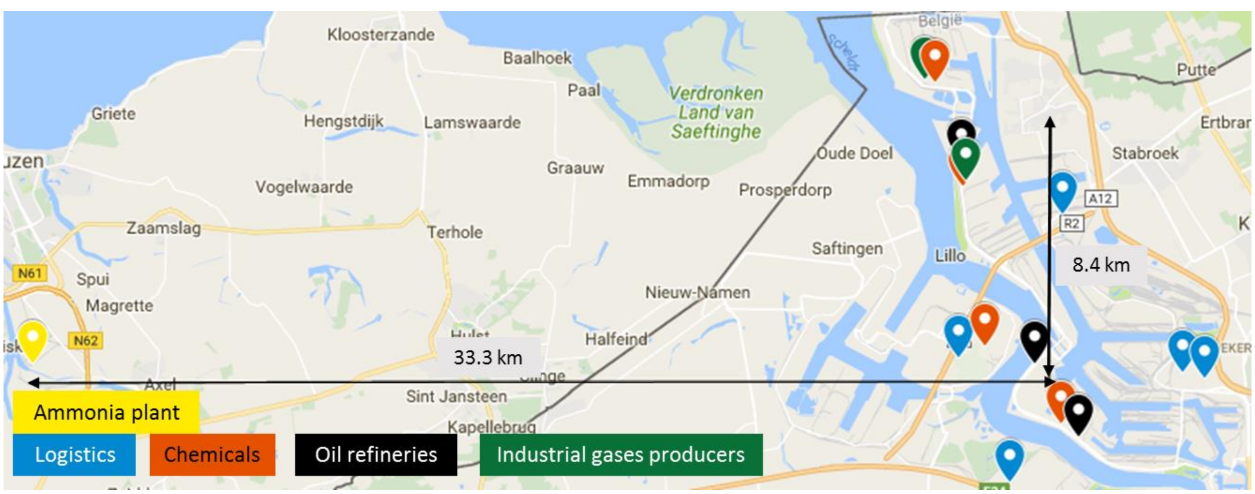


Figure 3-2: The industrial area of Antwerp

Error! Reference source not found. presents the industrial area of Linz in Austria, where the Voestalpine teel production plant is located. The plant will install a 6 MW PEM electrolyser as part of the H2FUTURE project and the hydrogen will be injected into the plant's gas network for use in various stages of steel production [50]. The industrial area of Linz is home also to a “Chemiepark” that houses 3 different chemicals plants and a large logistics centre, while it is also a port in the Danube river.

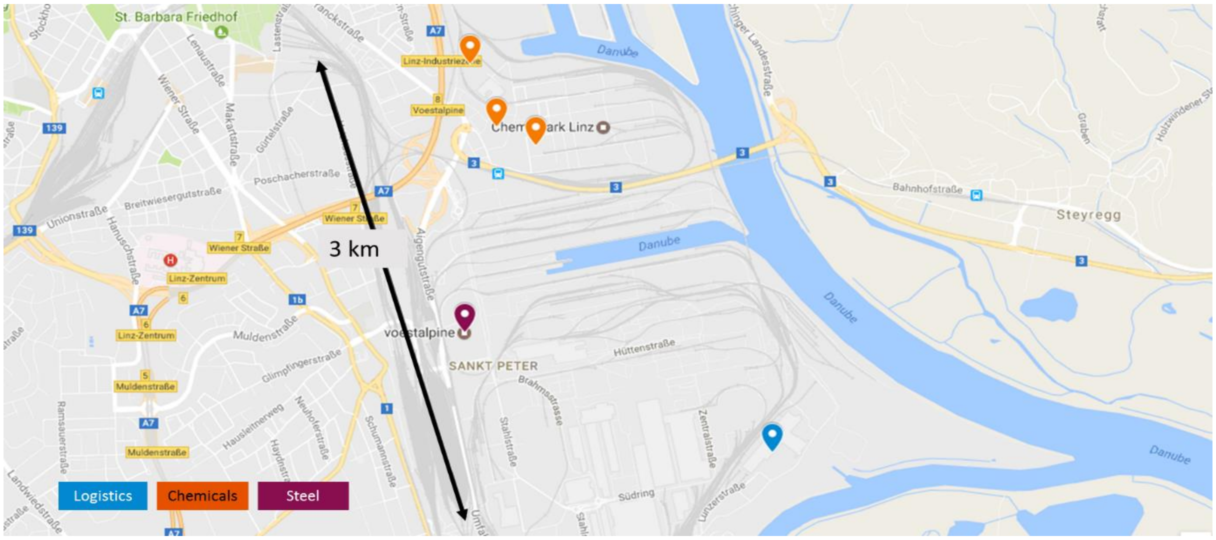


Figure 3-3: The industrial area of Linz, Austria

3.4 Selecting the types of industries

3.4.1 Hydrogen producers of the system

Judging from the industrial areas above refineries and chemicals are the majority of heavy industrial players in these areas.

Refineries are present in many of the major European ports, such as Antwerp, Rotterdam, Hamburg and Elefsina, taking advantage of the ease of delivery from the sea through oil tankers. Oil refining is not only a consumer of large quantities of hydrogen but a possible future adopter of P2H because of the stricter emission rules for the industry.

The presence of chemicals production sites is also clear, however because some of these chemical production sites might have no need for hydrogen or cover their needs through hydrogen that occurs as byproduct in processes like olefin production or chloralkali process. In addition there is not enough data regarding the hydrogen production and consumption for these plants, a refinery was chosen to represent the the hydrogen producer in the system.

3.4.2 Hydrogen consumers of the system

Due to the presence of a steel manufacturer in Elefsina (Xalivourgiki) and the adoption of P2H from Voestalpine in Austria, choosing a steel mill for the model is a reasonable choice.

The model will also include a floating glass industry, although the areas *above* shown above do not include one. This choice was a result of the electronics/semiconductors manufacturers having on average similar consumptions to the steel mills (750kg/day). Using a glass factory with a consumption of 300 kg/day, will allow for the model to include and study a smaller hydrogen consumption plant.

3.4.3 Hydrogen adopters of the system

Logistics providers have significant presence in industrial areas, sometimes constituting even the majority of companies there and will serve as consumers of centrally produced hydrogen since their needs can be very small and a capital intensive investment like on-site electrolysis might be prohibitive.

Forklifts are a likely early adopter of hydrogen fuel cells along with commercial vehicles. Internal combustion forklifts are out of the scope of this study and only electric forklifts are considered, since fuel cell alternatives have been manufactured and have been commercially used only for them.

Fleets of vans and trucks are also a pillar of the logistics sector, while zero emission vehicles for deliveries might very soon be a necessary, should internal combustion starts being prohibited from certain cities [51]. In this model a company that owns a fleet of trucks and vans was included, separately from the logistics warehouse (forklifts). This choice was made for two reasons:

1. Not every logistics provider owns the trucks/vans it uses to deliver its products; outsourcing is a popular choice, especially for smaller companies.
2. A more accurate mapping of the costs required to convert a fleet of non-passenger road vehicles to hydrogen. The same model can be potentially used, for example, for a bus terminal if different input data is used.

The categories of businesses of the system and their characteristics, are summarized in Table 3-1.

Table 3-1: Categories of businesses in industrial areas and their characteristics

Hydrogen producers	Refinery
• Heavy industry plant • Requires hydrogen in large quantities (tonnes/day) for its production processes. • Currently produces H_2 on-site using SMR	
Hydrogen consumers	Glass, Metallurgy
• Require hydrogen in medium quantities • Purchase hydrogen in bulk from vendors • Daily needs of 300-1000 kg per day	
Small consumers	Material handling vehicles, Truck, Vans
• Logistics sector • Hydrogen as fuel, (pressurized dispensing necessary) • Hydrogen needs can greatly vary depending the fleet size, generally < 200 kg per day	

3.5 Size of the system and its current energy needs

3.5.1 Hydrogen producers: Oil refinery

Depending on a refinery's complexity, by-product hydrogen from the catalytic reforming process can provide a large portion of the net hydrogen demand of the refinery. However, this by-product hydrogen has to be supplemented by in-house production, derived by steam methane reforming. The range of net hydrogen consumption according to [47] is 20-300 tonnes per day but can reach up to 800 tonnes in cases of very large and complex refineries. The hydrogen production and net demand of a typical French and German refinery is shown Table 3-2 according to [52].

Table 3-2: Hydrogen demand and production of a typical French and German refinery (tonnes/day)

Refinery process	H_2 demand		H_2 production		Net H_2 demand	
	France	Germany	France	Germany	France	Germany
Hydrocracking	604	896	0	0	0	0
Vacuum distillate desulfurisation	80	61	0	0	0	0
Middle distillate desulfurisation	134	178	0	0	0	0
Naphtha desulfurisation	59	101	0	0	0	0
FCC cracker	0	0	0	0	0	0
Catalytic reformer	0	0	435	843	0	0
Total	877	1239	435	0	442	396

The refinery in the model will have a daily net demand of 388 tonnes per day, assumed to be covered by a SMR unit. This sizing of the model's refinery is done based on the HELPE's refinery of Elefsina that has a refining capacity of 100 kbpd [53].

The plants sizes and hydrogen needs are summarised in Table 3-3

3.5.2 Hydrogen consumers: Glass and Metal industries

According to [47] a typical glass manufacturing site requires 300 kg of hydrogen every day and therefore this will be used in the model. A metal processing plant needs 0.1-2 tonnes of hydrogen per day for iron reducing [47]. This range matches the 6 MW electrolyser that was installed in the steel mill in Linz that is able to produce around 2 tonnes per day.[3] The metallurgy plant in the model was assumed to have on average, a daily consumption of 1.05 tonnes per day.

These businesses are assumed to purchase their hydrogen from a vendor and have it delivered by tube trailer, which carries 200 kg at 200 bar storage pressure. This delivery form has been chosen in order to use the prices consolidated in [54] for different industries and compare them to the results of the semi-centralised production scheme.

Table 3-3: H_2 needs of the model's industrial area

Industry type	Range of daily needs (tonnes/day)	Value chosen for model (tonnes/day)	Based on
Refinery	19.7-295 (up to 790 for some cases)	388	HELPE's Elefsina refinery
Glass	0.3	0.3	Average of range
Metal	0.1-2	1.05	Average of range

[3] Most electrolyser are able to produce 16 kg_{H2}/hour when continuous operation is assumed.

3.5.3 Logistics

Forklifts

The model assumes a warehouse operating a fleet of 10, Class 1 electric forklifts that operate for 3 shifts every day without necessarily being the whole fleet of the company. According to the questionnaires handed to industry representatives, only a portion of the total forklifts operate throught the day for all 3 shifts. However these lifts' operation is significantly more expensive because of the increased capital and operational expenses. The needs of the electric forklifts are calculated using data from [34] as well as [55].

The lifts are assumed to be powered by a 50 kWh battery with an effective (usable) charge of 35 kWh per shift, since the battery can only be operated between 20 % and 90 % of the available charge [55]. It is also assumed that the batteries have enough capacity for the 8 hour shift [34] [55]. It should be noted that the model's forklifts are assumed to operate under regular temperatures; as [35] notes the capacity of a forklifts battery can drop by 25% in freezing temperatures.

The electricity demand is calculated using the efficiencies of the battery chargers (84%) and according to these assumptions a logistics warehouse requires 42 kWh of electricity per forklift per shift for charging, reaching a total of 456,250 kWh per year for the modelled fleet (assuming 365 working days per year).

Each battery takes 8 hours to charge and 8 hours to cool down [fuel cell early markets]. As a result, lifts operating 3 shifts per day, 1 battery for every shift needs to be purchased, so they can be charged, cooled and used in rotation.

The battery changing times for battery electric forklifts can vary, however, the literature suggests an average time of 15 minutes including travel time and queuing [34] [55] [35].

Trucks & Vans

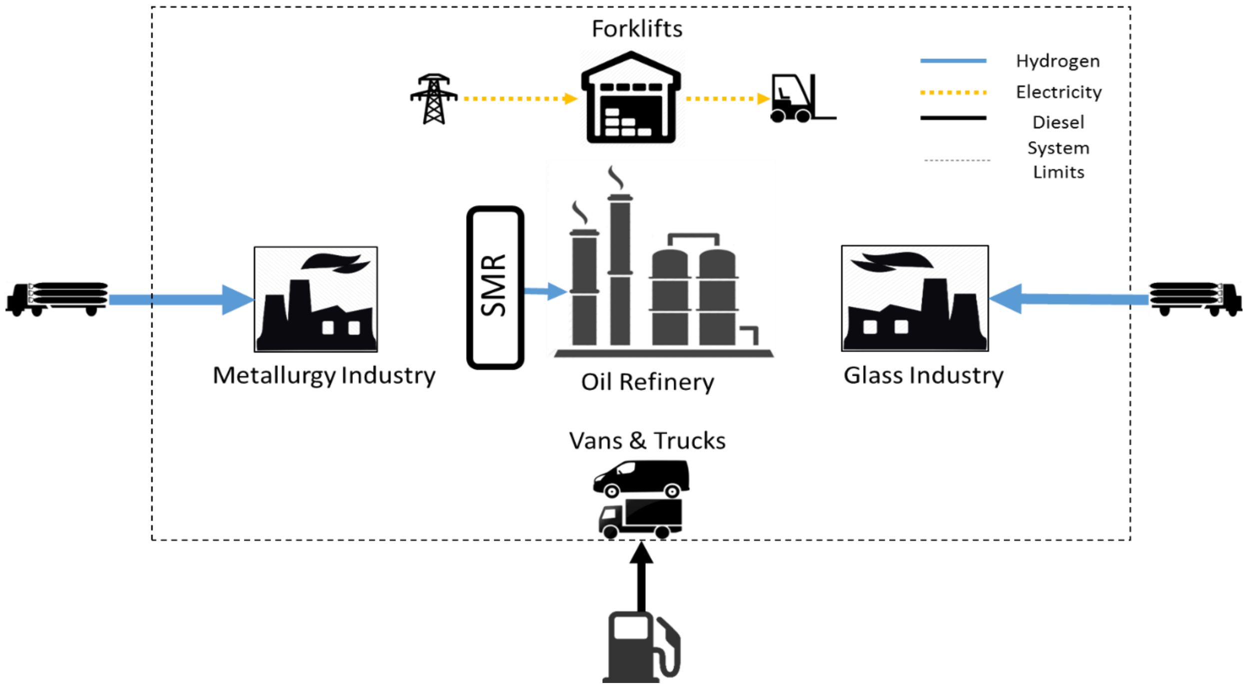
A fleet of 50 vans and 50 trucks (>7.5 tonnes) was assumed in the model. For the trucks of the system, Dixons South Europe data (acquired through questionnaire) was used. The company's trucks have daily trips of 250 km and use approximately 50 L of diesel each per day resulting in a 20 L/100 km fuel consumption. Because there was no input through the questionnaires for light commercial vehicles, to simulate the needs of a van fleet (<7.5 tonnes), for last mile delivery needs, Hyundai's H350 will be used, since the particular model has also been converted to an FCV by the company and a more accurate comparison can be made. Hyundai reports a consumption of 9.2 L/100 km for the diesel version [56]. The vans are assumed to do 100 km every day.

Table 3-4: Energy needs for small consumers/logistics

Fleet type	Size (No. of vehicles)	Workload (per day/vehicle)	Required energy (per day/vehicle)
Class I electric forklifts	50	3 shifts (8 hours)	126 kWh
Trucks (>7.5 tonnes)	10	250 km	50 L (diesel)
Vans (< 7.5 tonnes)	10	100 km	9.2 L (diesel)

Figure 3-4 shows graphically the different businesses of the system, their energy needs in terms of electricity, hydrogen or diesel, as well as their current sources.

Figure 3-4: Components of the system and their energy needs



4 Economic modelling of the system

4.1 Introduction

In this chapter the economic modelling of the industrial system is described. First the different scenarios for the system are presented, explaining the changes in the operational structure that take place in each business type. Then the methodology used to evaluate the different investments and to compare them is described along with its mathematical formulation and the economic assumptions made, together with a description of the technical aspects for every case.

4.2 Scenarios

4.2.1 Base case scenario

This scenario covers the conventional hydrogen production and supply methods currently used by the industry (Figure 4-1).

a) In the case of the oil refinery, hydrogen is assumed to be produced on-site, using steam methane reforming.
b) Steel and glass industries receive delivery of the necessary amounts of hydrogen through tube trailer delivery. The hydrogen is in gaseous form, pressurized at 200 bar and it is assumed to be produced by SMR. The vendor is considered a third-party, outside the system.
c) The warehouse (forklifts) and transportation company (vans/trucks), in the base case scenario are modelled after their current operations and therefore do not consume any hydrogen. The forklifts use batteries and the vans/trucks have diesel ICE.

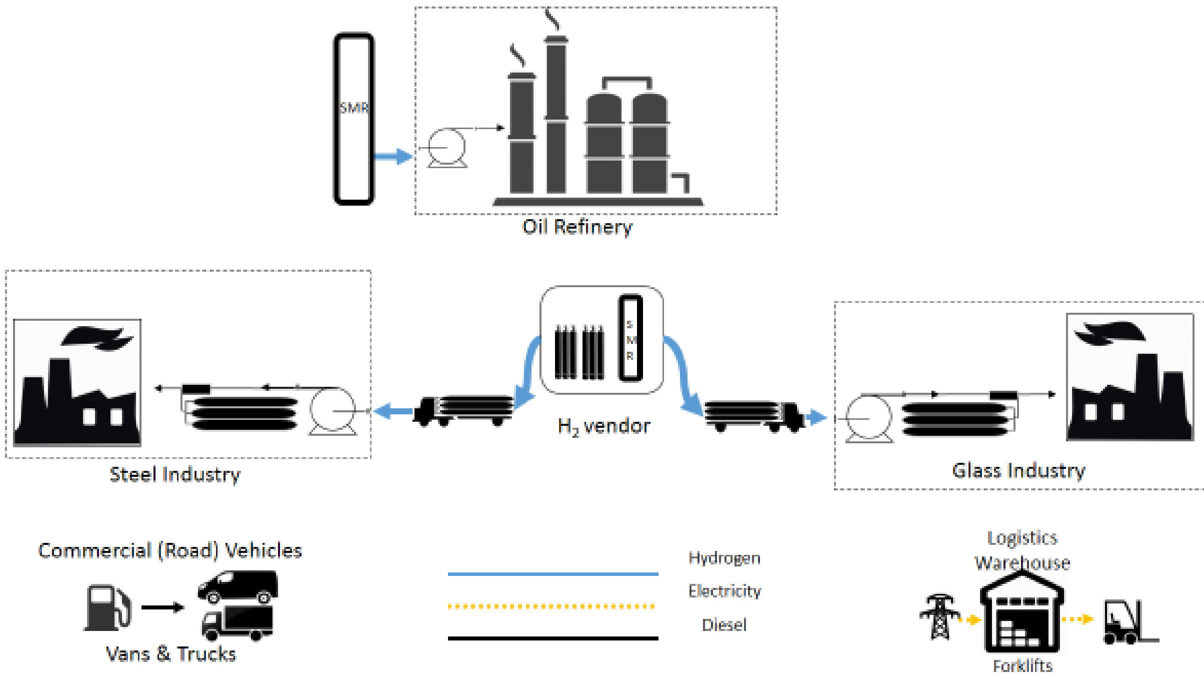


Figure 4-1: Base case scenario system

4.2.2 On-site production scenario

In this scenario hydrogen is produced through electrolysis at the sites of consumption. Two technological options are investigated regarding the electrolyser, alkaline and PEM, to opt for the most cost effective option. A schematic depiction of the hydrogen flow in this scenario can be seen in Figure 4-2.

a) The hydrogen producer covers part of its hydrogen needs using electrolysis, reducing the consumption of reformed methane hydrogen.
b) In the case of hydrogen consumers, there is no more delivery of hydrogen; an electrolyser is installed to cover all the needs of the site.
c) Hydrogen adopters, exchange the battery electric and ICE vehicles for fuel cell powered equivalents. The hydrogen needed is produced on-site through electrolysis.

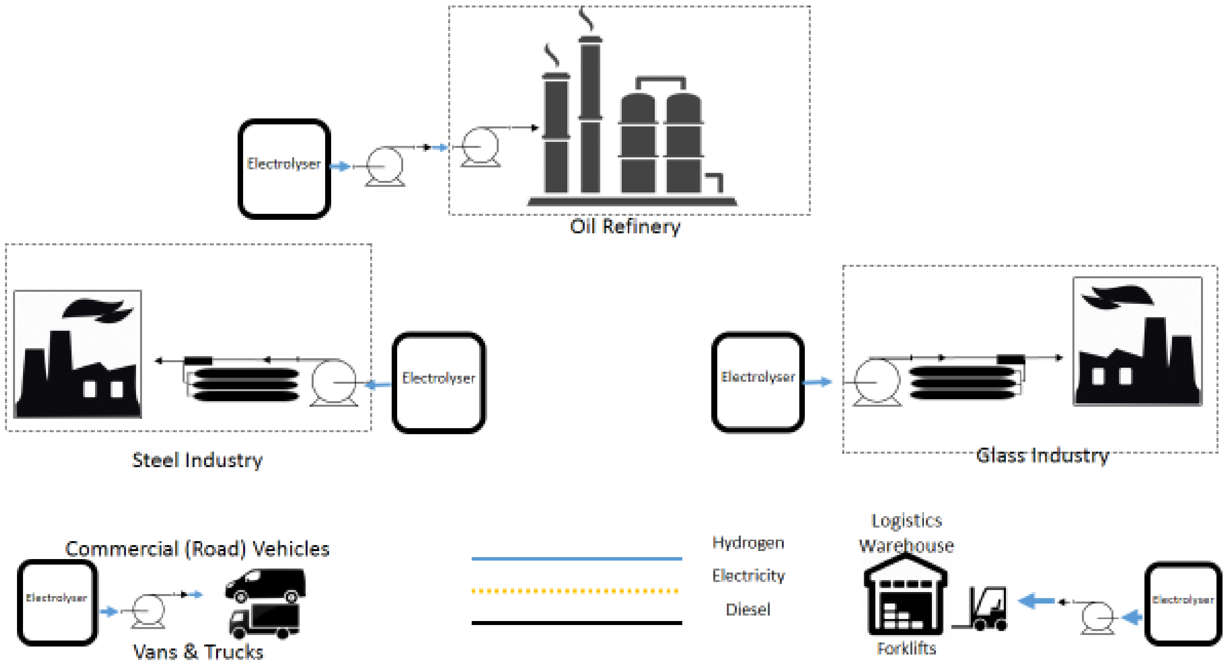


Figure 4-2: On-site (decentralised) production system

4.2.3 Semi-centralised hydrogen production scenario.

Finally, the third scenario examined, investigates the case where a large electrolyser is installed at the hydrogen producer's facility, with the aim to cover feedstock needs but also to sell hydrogen to the rest of the companies of the system.

In this scenario:

a) The hydrogen producer adds to the on-site production scenario a filling skid to compress hydrogen into tube trailers and a refuelling station.
b) Hydrogen consumers return to tube trailer delivery, however this time hydrogen originates from within the industrial system, and it is produced through electrolysis.
c) Hydrogen adopters still operate fuel cell vehicles, however, the hydrogen comes from the systems producer (oil refinery) in pressurized tanks via road delivery.

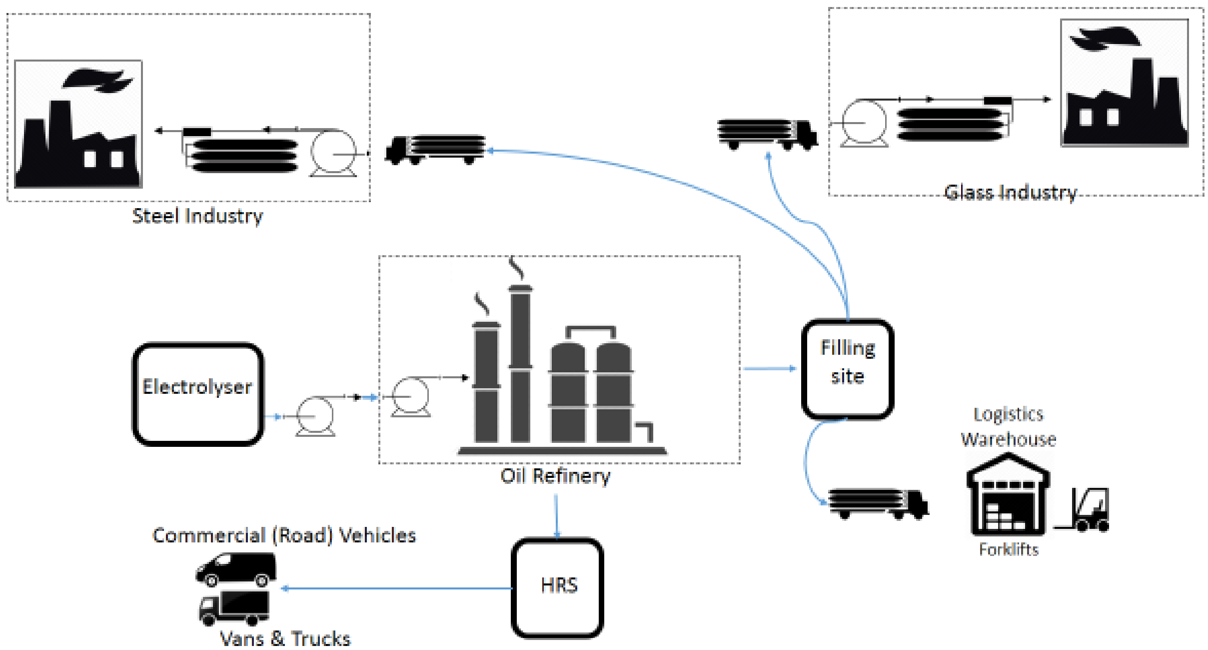


Figure 4-3: Semi-centralised production system

4.3 Methodology

To compare the scenarios with respect to their economic viability and their relative profitability, the Net Present Value (NPV) method was used. This method takes into account all of the investment's cash flows over its lifetime and discounts them to their present day value. Given the long term nature of these investments, it was deemed necessary to take into account the time value of money, and thus a method like the payback period method was deemed insufficient.

The NPV method requires both the cash inflows and outflows that occur during the lifetime of the investment. However, cash inflows that result from the normal operations of the companies of the system are out of the scope of this study, since it was assumed that these operations would not be affected by the origin of the hydrogen, be it electricity or methane. Assuming then, that the usage of electrolytic hydrogen in production processes or as vehicle fuel, is not producing any new income, the base case and on-site scenarios have no cash inflows in their NPV estimations.

Only exception to this, is the case of the refinery in the semi-centralised scenario. P2H in this instance produces new income, as hydrogen is sold to the other companies and these cash inflows will be taken under consideration.

After estimating the NPVs for all the scenarios, a comparison is made between them to determine the most profitable case.

The schematic flow of the methodological process can be seen in Figure 4-4.

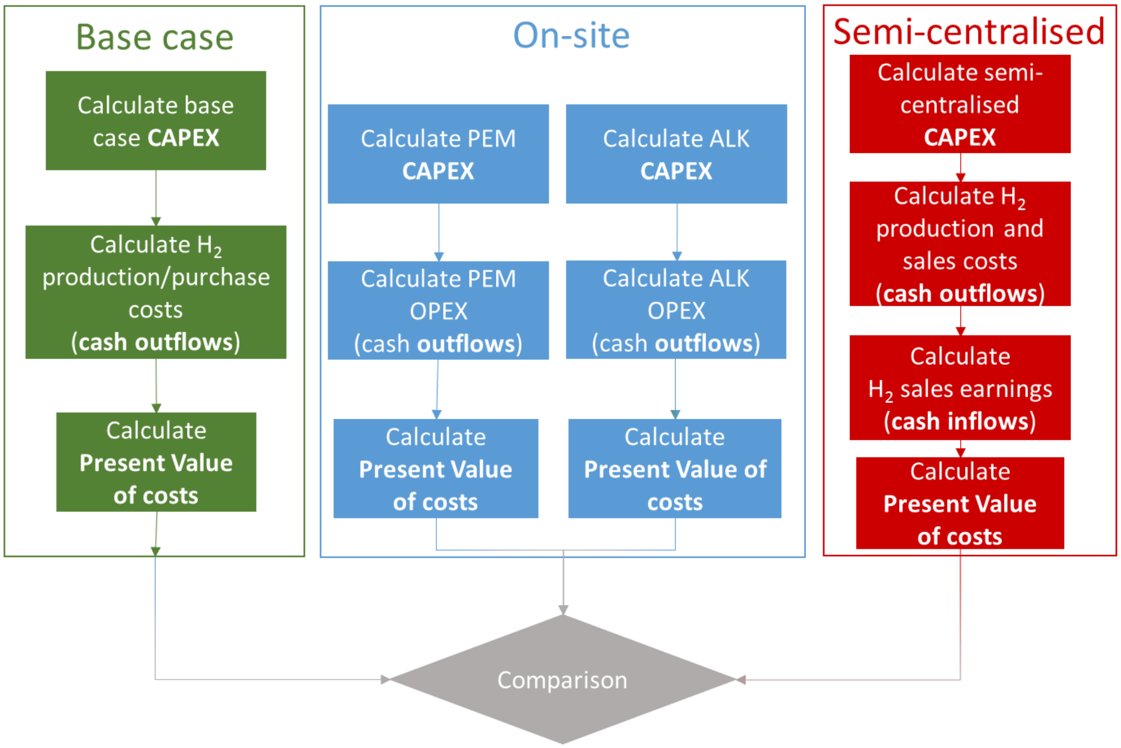


Figure 4-4: Flowchart of the methodology used

4.4 H2 Production Configurations

4.4.1 Base case

<u>Refinery</u>

For the base case of the refinery, the conditioning of the hydrogen was treated as a black box; the specifics of the process were not analysed and it was assumed that they were common across all scenarios. The production process as shown in Figure 4-5, includes only the steam methane reformer (SMR), after which the evaluation of the hydrogen cost is done.

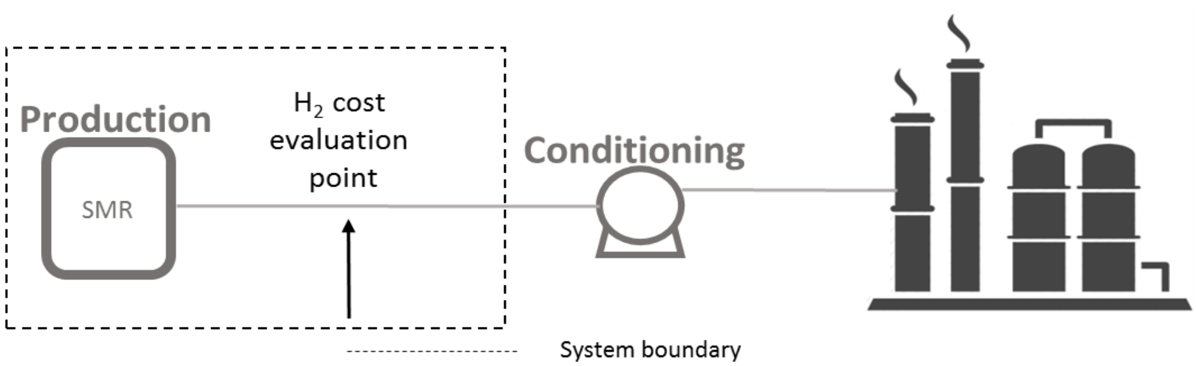


Figure 4-5: Refinery's hydrogen production process configuration

Glass and steel industries

For the glass/steel industries base case, it was assumed that tube trailers unload hydrogen in the company's storage by pressure difference only and no compressors are used in between the trailers and the on-site storage tanks. The storage was sized to accommodate the daily hydrogen needs only. The economics of the base case are calculated based on the price of the hydrogen, "at the gate" and the capital and operational costs of storage are added to it. Figure 4-6 depicts the system described.

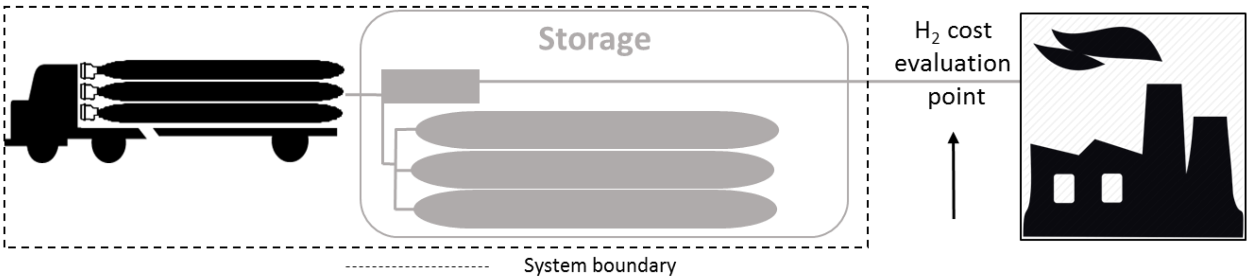


Figure 4-6: Glass and steel base case hydrogen process configuration

Logistics – Forklifts

For the base case, the warehouse was assumed to invest in a new fleet of conventional Class I battery electric forklifts along with all the equipment and infrastructure necessary for their operation.

For the capital costs, only the costs of the electric powertrain – the batteries – were considered, because the rest of the forklift (the *bare* forklift) is the same for either fuel cells or battery electric lifts. The charging of the batteries, requires specialised chargers and a dedicated room within the warehouse. Replacing the heavy batteries also requires dedicated battery swapping infrastructure.

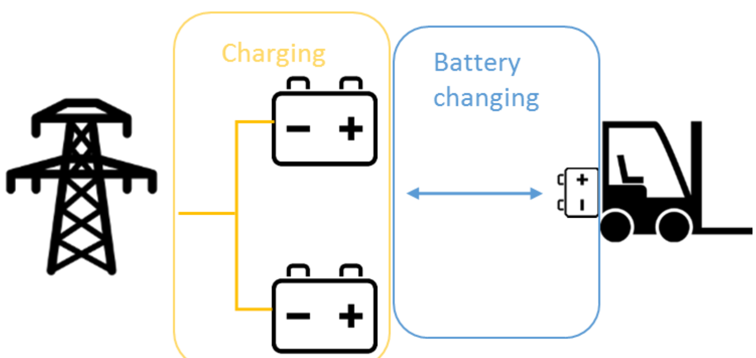


Figure 4-7: Forklifts base case operations configuration

The operational costs considered, apart from the electricity drawn from the grid, include the maintenance costs of the batteries, as well as the labour costs for the time consuming battery changing.

Logistics – Vans and Trucks

For the transportation company's base case scenario, like in the case of the warehouse, it was assumed that the company invests in a new fleet of vans and trucks with diesel ICEs. Unlike the case of the forklifts, the capital costs include only the purchase costs of the vehicles, while the operational costs consist of the fuel and maintenance needs of the vans and trucks.

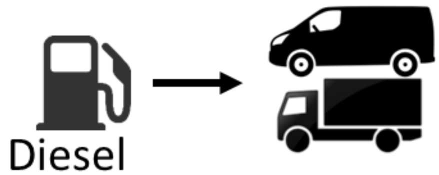


Figure 4-8: Vans and trucks base case operations configuration

4.4.2 On-site production

<u>Refinery</u>

For the on-site scenario it was assumed that the refinery replaces 10% of its SMR production with a P2H system. The electrolyser was assumed to be installed in order to replace only part of the hydrogen production. That is because current electrolyser technologies (PEM and ALK) have never been scaled to capacities that even approach the necessary ones for a complete replacement of the whole hydrogen production. In addition, it would be unrealistic to expect hydrogen produced by electricity to match the cost of hydrogen directly produced by methane, given the current electrolyser efficiencies as well as the electricity and natural gas prices throughout Europe.

Two different cases were made, based on the technology of the electrolyser, either PEM or Alkaline. Although the sizing of the equipment needed differs between the two, the processes are otherwise identical.

The production process includes the electrolytic hydrogen production system, which will be referred to only as electrolyser, even though it includes components such as hydrogen and oxygen managing system, water delivery managing equipment, thermal management equipment etc. The compression stage, includes only the compressor setup that increases the pressure to the storage tank pressure. The storage serves only as a buffer, helping with small increments in demand that might occur and is not sized to maintain back up quantities for cases of electrolyser shutdown (failures or maintenance). This is done because hydrogen storage occupies significant space and storing large quantities of pressurised hydrogen in the refinery grounds is difficult from a safety point of view. Since it was assumed that the SMR is still operational and the refinery's needs can be covered with it when needed the storage size was kept at a minimum.

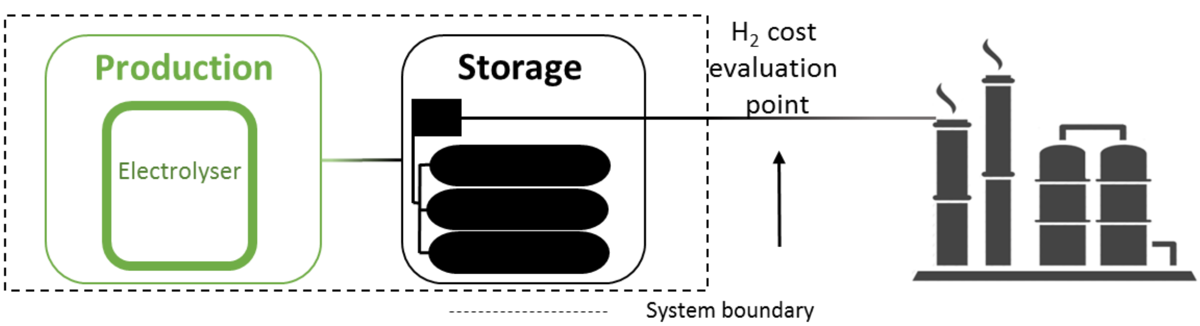


Figure 4-9: On-site production scenario's hydrogen production configuration for the refinery

Glass and steel

For the glass and steel industries, the on-site production scenario is similar to the refinery, with the exception of the size of the storage. The P2H system only replaces the hydrogen deliveries, while the necessary compression and storage equipment remains in place, only the production step was considered in this scenario calculations.

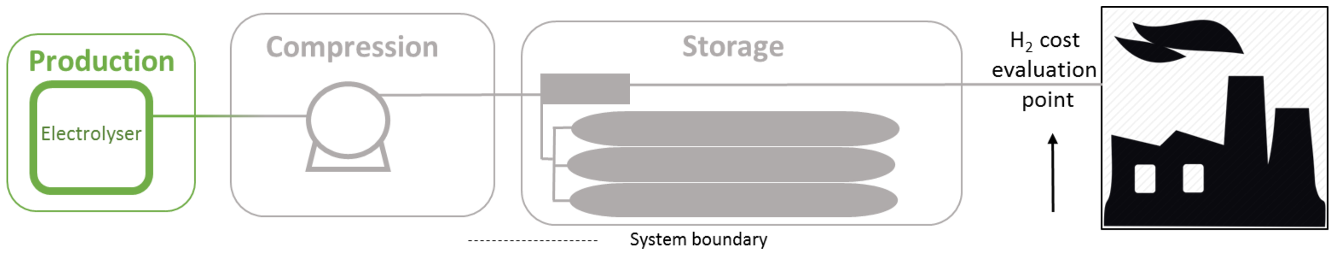


Figure 4-10: On-site production scenario's hydrogen production configuration for the glass and steel industries

Logistics – Forklifts

The on-site production scenario for the forklifts features a replacement of almost every part of the forklift operation process. In addition to the other cases, the operation of fuel cell forklifts now includes a dispensing step. This is essentially a small hydrogen refuelling station. Figure 4-11 presents the hydrogen system configuration for the warehouse.

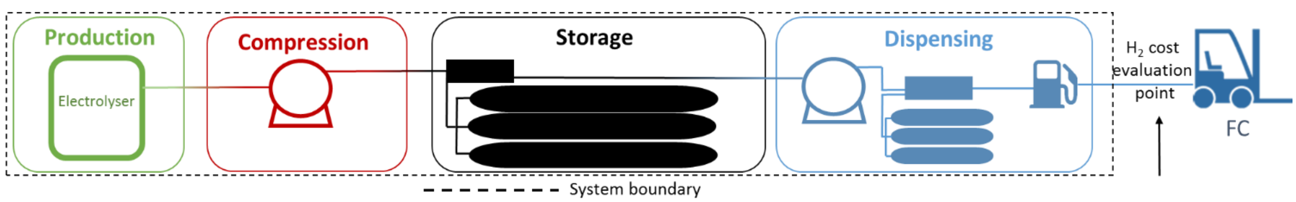


Figure 4-11: Forklifts on-site scenario hydrogen production and operations configuration

Logistics – Vans/Trucks

For the transportation company, the on-site production scenario is identical to the forklifts case. As seen in Figure 4-12, the operations of fuel cell vehicles requires production, compression, storage and dispensing of the hydrogen within the premises of the company.

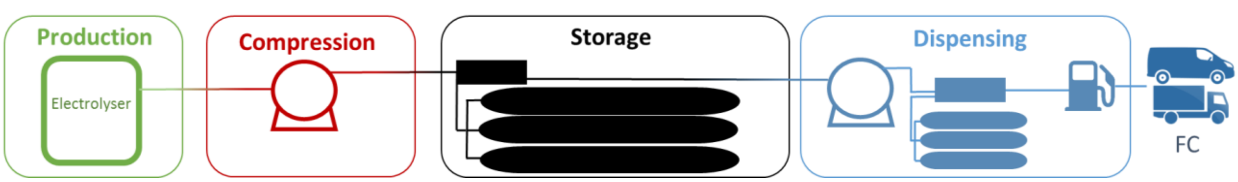


Figure 4-12: Vans and trucks on-site scenario hydrogen production and operations configuration

4.4.3 Semi-centralised production scenario

Refinery

The refinery, in the semi-centralised production scenario, while producing hydrogen to cover part of its own needs, it also acts as the provider of hydrogen for all the other players of the industrial complex. In addition to the on-site production scenario, a hydrogen refuelling station is added as well as a filling skid, to fill tube trailers. These trailers transport the hydrogen to the clients. The refuelling station and filling skid, resemble the dispensing process used in the forklifts and vans/trucks in the on-site scenario. They also include a cascade compressor and storage, only they are sized differently. The configuration is depicted in Figure 4-13.

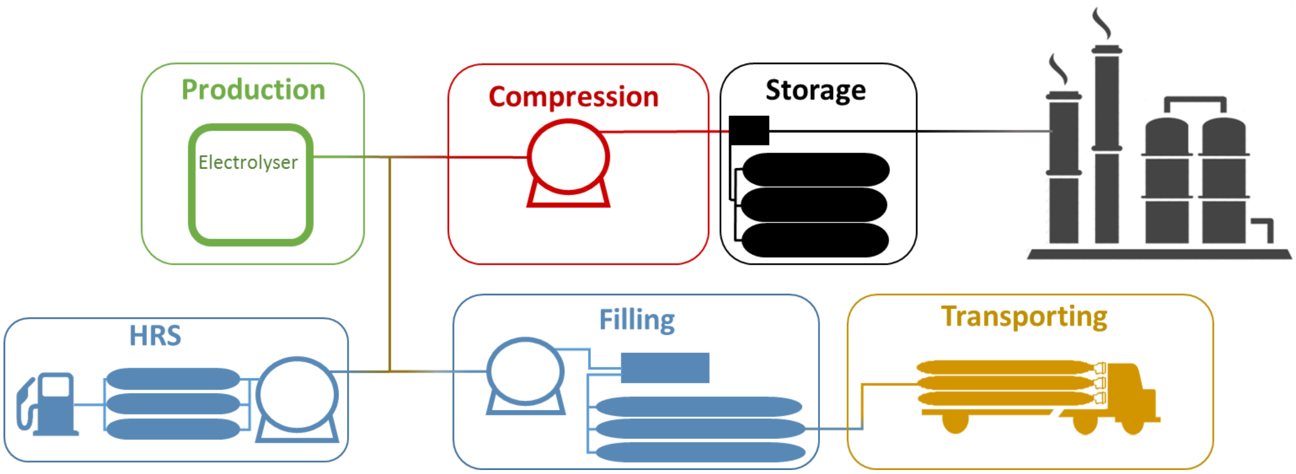


Figure 4-13: Refinery's hydrogen production and sales configuration for the semi-centralised scenario

Glass and steel

The glass and steel companies, in the semi-centralised scenario, have no difference from the base case, since they still purchase hydrogen and have it delivered by tube trailers, only in this case, it originates from the refinery, as shown in Figure 4-14.

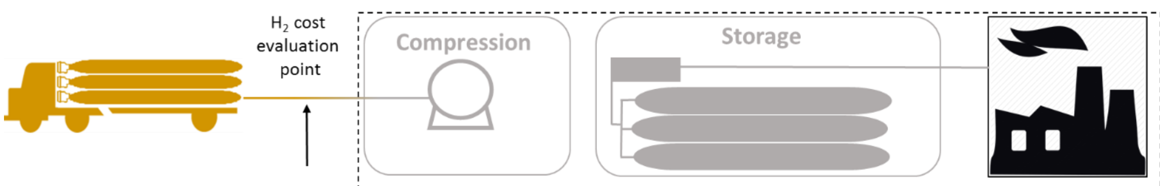


Figure 4-14: Glass and steel industry's operations configuration

Logistics – Forklifts

The production step can be omitted in this case, as the warehouse purchases the hydrogen from the refinery. The compression step remains, however, the compressor is sized differently since the hydrogen is already pressurized at 200 bar. In fact, it was assumed that the compressor only starts working after a certain pressure drop. Until then, hydrogen is transferred only by the pressure difference between the tube trailer and the storage. For the storage, it was assumed that the warehouse doesn't need to keep hydrogen back up, like in the case of the on-site production; instead the producer (refinery) takes that into account. The tanks are sized then, to only accommodate a bit over the daily needs.

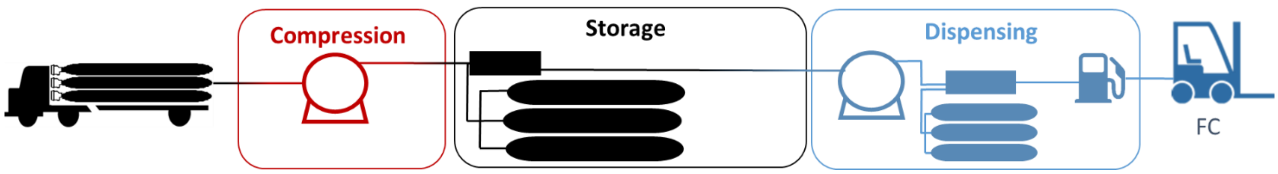


Figure 4-15: Forklift hydrogen and operations configuration for the semi-centralised scenario

Logistics – Vans and trucks

The other logistics company, follows a different operating procedure. Hydrogen is not delivered to the site, instead the refuelling happens at the hydrogen station, located at the refinery.

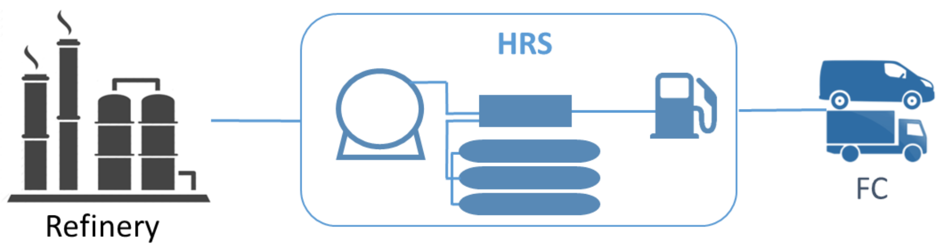


Figure 4-16: Vans and trucks operations configuration in the semi-centralised scenario

4.5 Mathematical Formulation

4.5.1 General definitions

4.5.1.1 Net Present Value

NPV is a measure of the profitability of an investment that is calculated by subtracting the present values of cash outflows, including the upfront capital costs, from the present values of cash inflows over a period of time. The present value of positive and negative cash flows is calculated using a discount rate, dictated by the market. The NPV is then, the sum of all the discounted cash flows.

Each net cash flow's present value is calculated using the following equation:

$$PV = \frac{R_{in_i} - R_{out_i}}{(1+i)^t}$$

where:
i: the time of the cash flow (year)
r: the discount rate
R_{in}: the cash inflow for the period t
R_{out}: the cash outflows for the period t

The Net Present Value takes then the following form:

$$NPV = \sum \frac{R_{in_i} - R_{out_i}}{(1+r)^i} - R_o$$

where R_0 is the initial costs.

4.5.2 Cost equations and breakdown

Refinery

Base case

For the base case, the initial capital costs C_0 were calculated using the costs of purchasing the equipment, installation and other one-time, non-equipment costs. The literature suggests costs for steam reformers based on their capacity and the equation is morphed in a way that reflects that.

$$C_0 = P * c_{SMR} + C_{install} + C_{non-equipment} \tag{1}$$

Where:

P:	daily production in kg
c_{SMR}:	cost of (uninstalled) steam methane reformer per kg of H_2 produced per day
$C_{install}$:	the cost of installing the SMR
$C_{non-equipment}$:	Non-equipment related costs, like engineering, commissioning and start up, licencing etc.

The operational costs consist of the SMR hydrogen production costs, the costs of the emissions allowances from the ETS and the reformer maintenance. Regarding the production costs, the calculations are performed based on a total cost per kg of H_2, pulled from the literature instead of using the cost of methane used. This way, other variable costs (e.g. for heating or the catalyst) are included in the calculations. For the costs of ETS allowances, an average carbon market price was used and multiplied with the emissions associated with SMR as noted in the literature review. These yield the following equation for estimating the SMR annual costs:

$$R_{out_i} = \frac{€}{kg} C_{H2\,SMR} * P + R_{ETS} + R_{maintenance} \tag{2}$$

where:

P:	daily production in kg
$C_{H2\,SMR}$:	cost of hydrogen per kg for SMR
R_{ETS}:	Costs of allowances based on an average price and the emissions of SMR per kg of H_2
$R_{maintenance}$:	Annual maintenance costs of SMR

The specific costs used in these equations are further described below in *Steam methane reforming*.

On-site production

For the on-site production scenario the initial capital costs include the costs for purchasing the electrolyser, the compressors and the necessary storage equipment as well as all the installation and non-equipment costs. These costs are further described below, in *Electrolysers* and *Compressors*.

$$C_0 = (C_{electrolyser} + C_{compressors} + C_{storage}) + C_{install} + C_{non-equipment} \tag{3}$$

The operational costs of these components are related to the electricity and maintenance costs for the electrolysers and the labour costs.

$$R_{out} = R_{electricity} + R_{maintenance} + R_{labour} \tag{4}$$

Semi-centralised scenarios

For the semi-centralised production scenarios, the capital costs include the filling site infrastructure, as well as the equipment for transporting the hydrogen to the consumers (tube trailers, tractors, etc.). Then, in the case of a central HRS, the associated capital and operational costs are also included.

$$C_0 = C_{production} + C_{conditioning} + C_{filling\ site} + C_{trasporting} + C_{other} + C_{dispensin} \tag{5}$$

The cash outflows include, as before, electricity, maintenance and labour costs, not only for the production part, but for the filling and transporting of the hydrogen as well.

$$R_{out} = R_{electricity} + R_{maintenance} + R_{labour} + R_{transporting} \tag{6}$$

In this scenario there is also a cash influx thanks to the sales of hydrogen to the different business in the system. This cash inflow consists of the sales of hydrogen the logistics company, the glass and steel produces and the

$$R_{in} = R_{sales} = R_{logistics} + R_{glass/steel} + R_{HRS} \tag{7}$$

For the sales of hydrogen no taxes were assumed. Although this might seem strange, it is true in many cases were new technologies are adopted, and governments indirectly incentivize them by reducing or eliminating taxes. This is also the case for hydrogen refuelling stations for FCEVs in Europe currently and it therefore safe to assume that at least for the beginning of such projects the same policy will apply.

Glass and steel

Base case

The base case of the glass and steel industries has capital costs related to the storage tanks and the compressor that aids the transfer from the tube trailers to them.

$$C_0 = C_{storage} + C_{compressor} + C_{install} + C_{non\ equipment} \tag{8}$$

The yearly cash outflows consist only of the purchase cost of the hydrogen delivered to them by the third party vendor.

$$R_{out_i} = C_{H_2 vendor} + \mathrm{C_{electricity}} + \mathrm{C_{maintenance}} \tag{9}$$

where:

$C_{H2vendor}$: the cost of purchasing H_2 from a vendor

$C_{electricity}$: the cost of electricity for the compressor

$C_{maintenance:}$ the costs of maintenance for compressor and storage

No ETS emissions allowances were considered, since there is no methane reforming on-site and therefore no emissions from hydrogen production (the vendor of the hydrogen is burdened with these emissions costs). These cash outflows remain the same for every year.

$$R_{out_{i+1}} = R_{out_i} \tag{10}$$

<u>On-site production</u>

For the on-site production scenario the initial capital costs include the costs for purchasing all the necessary production, conditioning and storage equipment and installation costs

$$C_0 = C_{production} + C_{conditioning} + C_{storage} + C_{install} + C_{non\ equipment} \tag{11}$$

The operational costs of these components are related to the electricity, maintenance costs and the labour costs.

$$R_{out} = R_{electricity} + R_{maintenance} + R_{labour} \tag{12}$$

<u>Semi-centralised scenario</u>

The glass and steel industries' semi-centralised scenario, is identical to the base case. The only exception is the price used for the calculation of the hydrogen purchasing costs, which was defined by the refinery's selling price and not by the third party vendor.

$$C_0 = C_{storage} + C_{compressor} + C_{non\ equipment} \tag{13}$$

$$R_{out_i} = C_{H_2\,vendor} + \mathrm{C_{electricity}} + \mathrm{C_{maintenance}} \tag{14}$$

Forklifts

<u>Base Case</u>

For the base case scenario, the capital costs were divided into the costs for purchasing the powertrain of the forklifts and the charging equipment, the cost of the floor space needed and any additional installation and civil works costs.

$$C_0 = C_{EV\ forklifts} + C_{charging} + C_{floorspace} + C_{install} + C_{non\ equipment} \tag{15}$$

The annual cash outflows assumed, stem from the operational costs and they consist of the electricity costs for charging, the maintenance of the forklifts and the necessary labour costs.

$$R_{out_i} = R_{charging} + R_{maintenance} + R_{labour} \tag{16}$$

It is important to note here, that the labour costs in this case refer to the costs of the forklift drivers only. No personnel was assumed to be needed for the operation of the electrolyser, as systems of this scale are sold as complete and automated solutions.

<u>On-site production scenario</u>

The capital costs, like the other companies include production and conditioning equipment. For the case of fuel cell forklifts though, the costs of the fuel cell powertrain of the lifts and the dispensing equipment necessary for refuelling were also considered.

$$C_0 = C_{FC\ forklifts} + C_{production} + C_{conditioning} + C_{storage} + C_{dispensing} + C_{install} + C_{non\ equipment} \quad (17)$$

The fuel cells of the forklift powertrain are not included in the installation costs calculations.

The cash outflows were calculated using the annual operational costs that include the electricity costs for the production and conditioning of the hydrogen, the maintenance of all the equipment and the labour costs of the lift operators.

$$R_{out_i} = R_{electricity} + R_{maintenance} + R_{labour} \quad (18)$$

Semi-centralised scenario

In the semi-centralised scenario, there is no hydrogen production infrastructure. The capital costs consist only forklifts powertrain and conditioning, storing and dispensing equipment for hydrogen.

$$C_0 = C_{FC\ forklifts} + C_{conditioning} + C_{storage} + C_{dispensing} \quad (19)$$

Cash outflows, include the purchasing costs of hydrogen from the refinery, and as previously, electricity costsand maintenance for all the equipment used to store and condition hydrogen as well as the FC stacks of the forklifts, as well as the labour of the forklifts operators.

$$R_{out_i} = R_{hydrogen\ costs_i} + R_{electricity} + R_{maintenance} + R_{labour} \quad (20)$$

Vans and trucks

Base Case

The structure of the NPV of the transportation company of the system, is less complicated than the forklifts NPV, since instead of in-house charging, the diesel ICE vehicles can refuel at a conventional petrol station. As a result, no capital costs for refuelling infrastructure or other capital costs, related to installation costs or civil work are considered.

$$C_0 = C_{vehicles} \quad (21)$$

The operating costs that constitute the cash outflows, consist of the diesel costs, the maintenance of the vehicles. No labour was assumed, as this costs would be exactly the same for the FCVs, given the similar refuelling times and otherwise similar operation.

$$R_{out_i} = R_{diesel} + R_{maintenance} \quad (22)$$

It could be argued that additional costs, like vehicle registration costs, insurance costs or road tax costs are also part of the costs (capital or operational) of a commercial vehicle. However, these costs have a small impact on the total cost of ownership and will probably be the same for FCVs and diesel ICE vans/trucks.

On-site production scenario

The on-site production is very similar to the forklifts case. The initial costs required are for the acquisition of the vehicles, the purchase of the production, conditioning dispensing equipment as well as the costs for installation and other work.

$$C_0 = C_{FC\ vehicles} + C_{production} + C_{conditioning} + C_{storage} + C_{dispensing} + C_{install} + C_{non\ equipment} \quad (23)$$

The annual cash outflows were determined by the annual costs of electricity and the maintenance of the vehicles and the infrastructure. Again, no labour was included, as explained above and the cash inflows are only the revenues.

$$R_{out_i} = R_{electricity} + R_{maintenance} \quad (24)$$

$$R_{in_i} = R_{revenues_i} \quad (25)$$

<u>Semi-centralised scenario</u>

For the semi-centralised scenarios, the capital costs seem similar to the base case scenario with only the cost of the vehicles burdening the company.

$$C_0 = C_{FC\ vehicles} \quad (26)$$

The cash outflows then, are:

$$R_{out_i} = R_{hydrogen\ costs_i} + R_{maintenance} \quad (27)$$

4.6 Cost Assumptions and Considerations

General cost assumptions

Some cost assumptions that were used in all the scenarios are presented below, including installations costs and other non-equipment costs

<u>Installation costs:</u>

The installation costs for the different pieces of equipment were calculated on a per cent basis of the capital costs and were meant to account for the one-time labour costs. In the different scenarios, these costs are thought to amount to 12% of the total equipment purchase costs.

<u>Non-equipment costs:</u>

As with the installation costs, the non-equipment costs are calculated on a per cent basis of the total purchase costs. For these costs, an additional 20% of the total equipment purchase costs. These costs include permits, start-up costs and any other costs arise as onetime expenses during the building phase.

Steam methane reforming

According to [57] and [58] the price for a reformer of 3.2 tonnes_{H2}/day was set to about 5200 $/$\text{kg}_{H2}$/day or 4230 €/kg/day. This cost is assumed to include the (uninstalled) cost of compressors and Pressure Swing Adsorber that may be needed for the SMR.

Delivered H_2 average prices

Table 4-1 shows the average prices of delivered hydrogen for different EU countries according to an FCH-JU study [47]. These prices are sourced from a survey, and the reasons behind the differences among countries and industries are not well documented.

Most notably, Germany seems to be an outlier when compared to the other three countries, and has been excluded from the average price calculations used in the calculations of the model. Also, the price differences among the industries seem counterintuitive at first; metallurgy shows higher average prices than glass, on all countries even though their demand is generally greater. One possible explanation could be that the large metallurgical plants are more isolated and therefore the transportation costs (a major cost component) is much higher. In the calculations the average for every industry will be used for the base case scenarios.

Table 4-1: Hydrogen prices (€/kg) for 200kg tube trailer delivery (@200 bar)

Industry	Germany		France		UK		Denmark		Average		
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Average
Fat and Oils	3.2	4.1	8.5	8.7	5.5	10.3	7.9	8.5	6.3	7.9	7.1
Glass	3	3.8	7.9	8.1	5.1	9.6	7.3	7.9	5.8	7.4	6.6
Electronics	3	3.9	8.1	8.3	5.3	9.8	7.5	8.1	6.0	7.5	6.8
Specialty Chemicals	3.6	4.6	9.6	9.8	6.2	11.6	8.8	9.6	7.1	8.9	8.0
Average	**3.8**	**4.9**	**10.2**	**10.4**	**6.6**	**12.3**	**9.4**	**10.2**	**7.5**	**9.5**	8.5
Metallurgy	3.8	4.9	10.2	10.4	6.6	12.3	9.4	10.2	7.5	9.5	8.5
Utility Power	4.8	6	12.9	13.2	8.4	15.6	11.9	12.9	9.5	11.9	10.7
Fuel Cell Transport	5.4	7	14.4	14.7	9.4	17.4	13.3	14.4	10.6	13.4	12.0

Electrolysers

<u>Capital costs</u>

To model the costs for the electrolysers, data from [54] was used to produce an equation capable of returning the capital cost per installed electrolyser capacity. The resulting equations are presented below in *Figure 4-17*.

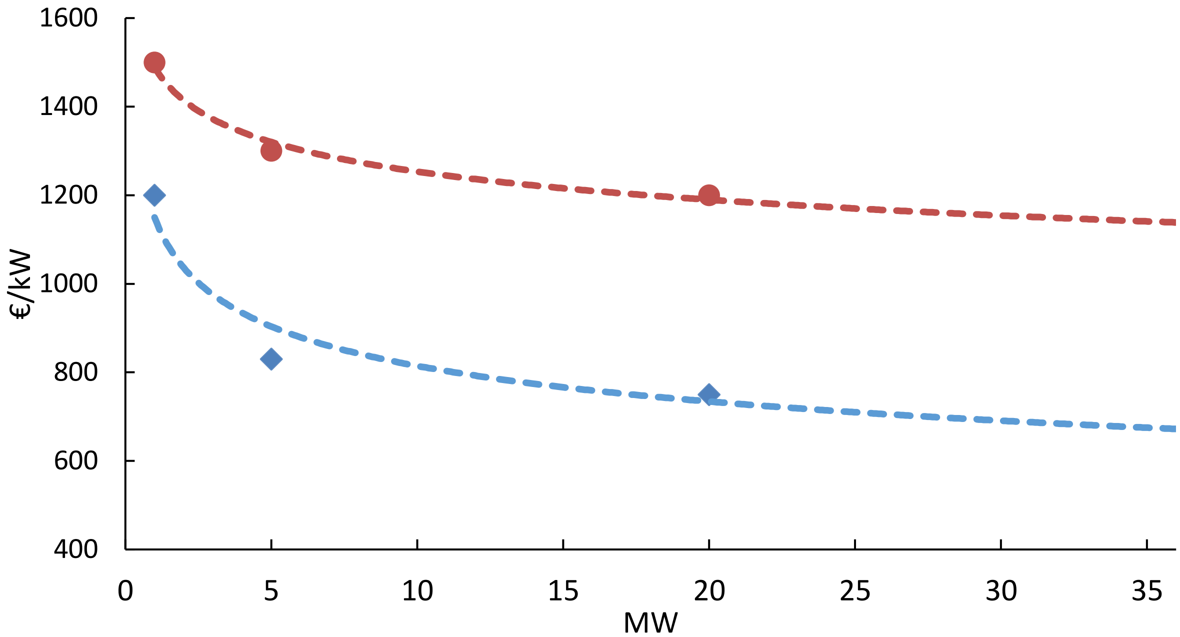


Figure 4-17: Cost functions of electrolyser technologies per installed kW

The trend lines yield the following equations:

$$y = 1489.3\,x^{-0.075} \qquad (PEM) \tag{28}$$

$$y = 1157.8\,x^{-0.159} \qquad (ALK) \tag{29}$$

where x is the electrolyser capacity in MW. Please note that the costs are presented per kW of installed capacity, as this is the industry standard.

Although increasing the installed capacity results in lower per kW capital costs, the rate of cost reduction is decreasing, and should be zero for very large installations after 35 MW.

$$€/kW_{ALK} = \begin{cases} 1136.9 * Capacity^{-0.145} & for\ Capacity < 35\ MW \\ 650 & for\ \ Capacity > 35\ MW \end{cases} \tag{30}$$

$$€/kW_{PEM} = \begin{cases} 1489.3 * Capacity^{-0.075} & for\ Capacity < 35MW \\ 1120 & for\ \ Capacity > 35\ MW \end{cases} \tag{31}$$

In Chapter 2 the efficiency ranges for both ALK and PEM were presented. For the model's electrolysers efficiencies of 65% for ALK and 55 % for PEM were assumed resulting in consumptions of 50.7 and 60 kWh/kg_{H2} respectively. The output pressures were rated at 5 bar for ALK and 20 bar for PEM.

Table 4-2: Efficiencies and output pressures of electrolysers

	ALK	PEM
Efficiency	65 %	55 %
Output Pressure	5 bar	20 bar

The required capacity was calculated by taking into account the efficiencies of each electrolyser type using the following equation:

$$C = \frac{n}{24 * 1000} * Q * C_f \tag{32}$$

where:

- C = capacity of electrolyser (MW)
- n = efficiency (kWh/kg_{H2})
- Q = daily production
- C_f = capacity factor

Therefore the electrolyser is sized to produce the daily needs when working all day long at 75% of its maximum capacity.

<u>Operational Costs</u>

The electricity consumption of the electrolyser was calculated using the following equation:

$$E = C * C_f * t_{op} \tag{33}$$

where:

- E = consumption of electricity (kWh)
- C = electrolysers or compressor capacity (kW)
- C_f = capacity factor (75%)
- t_{op} = time operating

The capacity factor denotes the ratio of the actual capacity to the maximum capacity the electrolyzing unit is capable of. The capacity factor for the considered electrolysers will be 75%.

A fixed OPEX of 1.5% of the CAPEX was also assumed to account for various maintenance of minor parts that might need replacement. Although electrolyser systems are designed for a 20 year lifetime, the electrolysing stack can degrade much faster. Accounting for that, a replacement at 10 years of operation was considered. According to [58] the cost of the stack accounts for 47% of the initial cost of the electrolyser. However to account for the future reductions in stack costs, a more optimistic 30% of the initial stack cost was considered.

Additional labour:

One additional worker for each of the three shifts was included in the cases of P2H production in the refinery. As experienced from other P2H projects, these systems require little oversight. The electrolyser might also be monitored remotely from the manufacturer, with actual intervention only when required or during the scheduled maintenance.

Compressors

<u>Capital costs</u>

The CAPEX required for the compressors is calculated by the following equation as described in [54]:

$$CAPEX_{compressor} = 100{,}000 \left(\frac{H_2\ Flow\ rate}{50}\right)^{0.66} \tag{34}$$

$$+\,300{,}000\left(\frac{H_2\ Flow\ rate}{Flow\ rate_{ref}}\right)^{0.66}\left(\frac{\left(\frac{Pressure_{Out}}{Pressure_{In}}\right)}{\left(\frac{Pressure_{out_{ref}}}{Pressure_{in_{ref}}}\right)}\right)^{0.25}\left(\frac{Pressure_{Out}}{Pressur_{out_{ref}}}\right)^{0.25}$$

Where the *ref* stands for a compression system used for reference, with 50 kg/h flow rate, 30 and 200 bar input and output pressure.

<u>Operational costs</u>

Tractebel and Hinicio's study [54] provided only electricity consumptions for specific inlet and outlet pressures. Thus, to estimate the consumption of electricity for a wider range of compressions setup, the more detailed equation 35 from [58] was used.

$$\mathrm{P_{th}} = \mathrm{mZRT_1\ N_{st}}\ (\frac{\mathrm{k}}{\mathrm{k}-1})[\left(\frac{\mathrm{Pressure_{out}}}{\mathrm{Pressure}_{in}}\right)^{\frac{\mathrm{k}-1}{\mathrm{kN_{st}}}} - 1] \tag{35}$$

where:

- P_{th} = theoretical power requirement
- m= mass flow rate
- Z = compressibility factor
- R= gas constant
- T_1 = inlet gas temperature
- N_{st} number of compression stages
- k = heat capacity ratio (1.4 for hydrogen)
- p_2 = outlet pressure
- p_1 = inlet pressure

The real power of the compressor required is found by taking into account the isotropic efficiency of the compressor, which is assumed in this analysis to be 88%. Therefore:

$$P_{real} = \frac{P_{th}}{0.88} \tag{36}$$

The electricity consumed by the compressor was then calculated based on the hours that the compressor operates.

$$E = P_{real} * t_{op} \tag{37}$$

where:

- E = consumption of electricity (kWh)
- t_{op} = time operating

The storage compressors connected to an electrolyser, operate simultaneously with the electrolyser. Storage compressors fed with hydrogen from tube trailers, operate only during every delivery and only when compression is needed. The time then was calculated based on the hydrogen mass compressed and the flow rate of the compressor.

To size the compressors the following assumptions were made:

1. For storage compressors, the hydrogen is fed directly from the electrolyser to the compressor at the electrolyser's output pressure and with a flow rate equal to the hydrogen production rate of the electrolyser.
2. For compressors used in the cascade filling systems, the compressor draws hydrogen from the storage, after every refuelling event. The flow rate was set to the peak flowrate of the system. *The compressor power, is directly related to the electricity consumption of the site, an important cost factor. To accurately size the compressor, an analysis of the usage pattern should have been made, especially for the cases where vehicle refuelling takes place and significant changes in traffic in the refuelling station occur. However, this falls out of the scope of this study, and the refuelling is supposed to be evenly spread out, throughout the day.*
3. The hydrogen is compressed to the storage's pressure through 1 compression stage.

Based on these assumptions, for each electrolyser type a different storage compressor had to be modelled, with 5 and 20 bar inlet pressures for ALK and PEM electrolysers respectively. Therefore the following equations apply to the storage compressor design:

$$P_{electrolyser_{out}} = P_{compressor_{in}} \tag{38}$$
$$P_{compressor_{out}} = 50\ bar \tag{39}$$
$$\dot{m}_{compressor} = \dot{m}_{electrolyser} \tag{40}$$

where:

- P: the pressure
- m: mass of hydrogen refuelled
- ṁ: the mass flow rate

Forklifts

Since this study aims to show the differences of the economics when investing in hydrogen forklifts instead of battery electric ones, and the bare forklifts (forklift without the power supply unit – battery or fuel cell stacks) are the same in both cases [54] [34], the capital cost of acquiring and the operational costs of maintaining the bare lifts were not taken into account in the calculations.

Capital costs

The default forklifts used in this scenario are assumed to be Class I electric forklifts (1-6 tons) and therefore all the related costs are calculated for this lift type. This assumption was made, since Class I forklifts have more time consuming battery changes and can be more likely to require a battery change at the end of the shift, because of their higher energy demands.

Battery powered electric forklifts use lead acid batteries that need to be charged and cooled down before use these batteries require 8 hours for charging and another 8 hours for cooling down and are, on average, able to last for an 8 hour shift. The cost of each battery was assumed at €5000, using the estimates from [35]. Replacements for these batteries is also taken into account since literature indicated that the battery lifetime is 5 years [54] [34]. The batteries also require specialised chargers and every charger can accept a new battery as soon as it is free from the previous one. Therefore, one charger is required for every forklift operating 3 shifts per day. The lifetime of the chargers is on average 7.5 years according to [34] and their cost was assumed to be €2500 per unit.

Floor space occupied by the charging infrastructure is also a significant cost that is taken into account, because it reflects loss of storing capacity for the warehouse. The authors of [54] reports that the battery room costs €356 per lift and that battery changing equipment for up to 40 battery changes per day, costs €8100.

All these costs are summarised in Table 4-3:

Table 4-3: Capital costs of battery electric forklifts

	Per unit (€)	Units needed per forklift
Battery	4,500	3
Chargers	2,500	1
Changing equipment	8,438	0.08
Battery room cost	356	-

For the hydrogen powered forklifts, the fuel cell system essentially replaces the battery. Prices for the fuel cell module range from €27,000-€29,700 per unit with a lifetime of 10 years [54] [34]; 28,000 € per FC module was used in the calculations.

<u>Operational costs</u>

According to [54] the energy requirement of a Class I forklift per shift is 26.7 kWh. To obtain that, bearing in mind that the efficiency of the electrical powertrain is 76% and the discharging of the battery is 80% efficient, a battery capacity of 44 kWh is needed. To charge this battery for every shift, 52.3 kWh of electricity have to be drawn from the grid, since the charging process is only 84% efficient. The energy flow is presented in Figure 4-18.

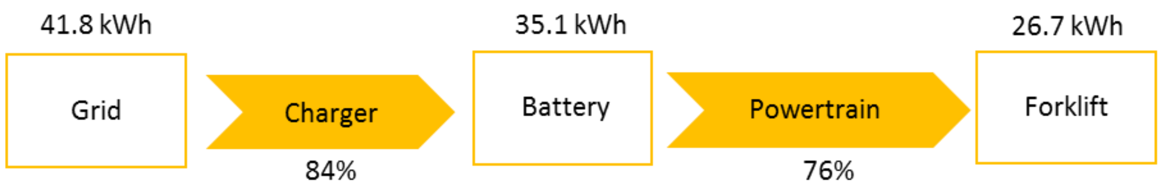


Figure 4-18: Battery charging flowchart - Energy drawn from the grid per battery

Hydrogen forklifts have on-board hydrogen tanks with a capacity of 1.8 kg. Given that hydrogen has an energy density of 33 kWh/kg_{H2}, this translates into 59.4 kWh worth of energy. Assuming a powertrain efficiency of 48% [54], to deliver the 26.7 kWh necessary per shift, 1.68 kg of hydrogen are consumed. The energy flow from refuelling to wheels is presented in Figure 4-18. This does not include the energy flow for production and conditioning of the hydrogen.

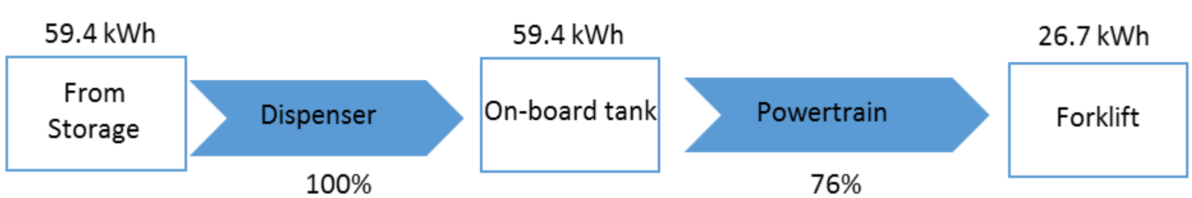


Figure 4-19: Hydrogen refuelling flowchart – From storage to forklift, not including production

Labour costs from the battery changing or refuelling of the forklifts was also taken into account. For the electric forklifts, battery changes consume 10-20 minutes per change [54] [59] [34] [55]. An average time of 15 minutes was assumed in this study. Regarding the hydrogen fuel cell lifts, as shown above, the tank of the hydrogen forklifts is almost empty when refuelling takes place at the end/start of a shift and 1.8 kg of hydrogen need to be dispensed. The refuelling equipment was sized for 5 minute refuellings. In both occasions travelling time was excluded, as it was assumed it would not be altered by the addition of fuel cells

Table 4-4: Battery changing and H_2 refuelling times (Class I) – excluding travel time

Battery changing time (minutes)	H_2 refuelling (minutes)
15	5

The maintenance cost of the batteries is estimated according to [fuel cell early] at 1620 €/year/battery. For the fuel cells, a maintenance cost of €2,000 per fuel cell module was assumed [tco nrel][fuel cell early markets]

Annual maintenance was also considered for both types of forklifts.

Maintenance (€/year/lift)		Source
Battery	Fuel Cell	
913	450	[55]
1620	1944	[34]
3240	648	[59]

Table 4-5: Operational expenses (OPEX) for battery electric forklifts (base case scenario)

Operation	Expenses (€/year/lift)
Battery maintenance	16,87
Electricity (consumption + installed power fee)	3,555
Labour (battery changing)	7,650
Total	**12,892 €**

Since this study aims to show the differences of the economics when investing in hydrogen forklifts instead of battery electric ones, and the bare forklifts (forklift without the power supply unit – battery or fuel cell stacks) are the same in both cases [34] [35], the capital cost of acquiring and the operational costs of maintaining the bare lifts were not taken into account in the calculations.

Vans/trucks

The vans have been modelled after the Hyundai H350, a light commercial vehicle used for goods deliveries, a hydrogen powered variant of which was recently introduced by the company. For the trucks, although only a few examples have been showcased until now, the ESORO-COOP truck mentioned in the previous chapter, possibly fits the needs of European companies. Therefore, the cost assumptions and were made after its diesel and hydrogen variants.

Capital costs

For the capital costs of the base case, costs of €34,000 per van and €80,000 per truck were assumed. These are the prices for the diesel Hyundai H350 [56] as well as the diesel MAN TGS truck. For the fuel cell vehicles, a cost of three times that of the diesel was used based on a costs comparison of diesel and fuel cell buses.

Table 4-6: Capital costs of vehicles of a tranportation company

	Capital costs

	Capital cost - Diesel (€/vehicle)	Capital costs - Fuel cell (€/vehicle)
Vans	34,000	102,000
Trucks	80,000	240,000

Any additional equipment contributing to upfront capital costs, was assumed to be necessary both in cases of diesel and fuel cell powered vehicles and therefore it was not included in our comparative analysis.

Operational Costs

To estimate the operational costs, the maintenance and fuel costs of a van/truck fleet were calculated. More specifically, a price of 1.2 €/L was assumed for the diesel fuel needs. For the vans, a fuel consumption of 10 L/100km was used, which is close to the official figures Hyundai claims for the H350 while for the truck a consumption of 35 L/100 km was assumed based on [60] [61].

For the maintenance, a cost of 0.06 and 0.09 €/km for vans and trucks respectively was used. Average daily trips of 100 and 250 km were assumed for the vans and trucks respectively, based on the questionnaires collected from logistic centres in Athens, Greece.

Table 4-7: Annual operational costs

		Fuel Consumption	
		L/100km	Total Cost (k€/year/fleet)
Diesel	Vans	35	148.8
	Truck	10	212.5
		Maintenance cost (€/km)	Total Cost (k€/year/fleet)
Maintenance	Vans	0.06	20.4
	Trucks	0.09	153.0
Total			534.6

Electricity Costs

For the construction of the on-site production and semi-centralised scenarios, the electricity costs were perhaps the most important factor in the cost estimation of the produced hydrogen, since both the production and conditioning processes are electricity intensive.

The authors of [62] report that an average price of 0.0843 €/kWh for flat glass manufacturers in the EU.

For the steel industry, according to [63], in Germany and Austria the prices of electricity are between 0.060-0.065 €/kWh, including any electricity self-generation within the site, while in Italy the cost per reaches 0.110 €/kWh. The authors claim, that an average plant requires approximately 1600 GWh of electricity, only 10% of which (160 GWh) are purchased from the grid. Taking also into account the prices reported in [64] for similar customers, a price of 0.065 €/kWh was used in the steel mill.

For the refinery, data from the large consumers category described in [64] was used and the cost of electricity for these companies was set at 0.050 €/kWh.

Based on the questionnaires collected from logistic centres in Athens, Greece, a warehouse has an electricity cost less than 0.07 €/kWh and an electricity consumption of 550-950 MWh/year. Acknowledging the fact that electricity prices in Europe are higher as shown in [64], a more representative average of 0.072 €/kWh was chosen based on this annual consumption as well as the projected consumption of the electrolyser, that would significantly change the customer profile of an otherwise smaller consumer. Storage

The low pressure storage units were assumed to be in place for most of the cases, to assume that operations resume as normal in case of an electrolyser breakdown or during the required maintenance. This storage tank is a low pressure tank where the hydrogen is kept at 50 bar, and has a cost of 400 €/kg [early business cases].

Dispensing

The dispensing process includes the compression of the stored hydrogen (from 50 bar), to the banks of the cascade storage, and the filling of the on board tanks through the dispenser. This process is the same for all the scenarios and cases.

The high, medium and low pressure tanks of the cascade storage system contain hydrogen at pressures of 480, 320 and 140 bar respectively. The cascade storage is used to dispense hydrogen to the on board hydrogen tanks of forklifts and vans/trucks at 350 bar, usually without further compression in between using only the pressure difference between cascade and on board storage. The cylinders are utilized in ascending order of pressure (low, to medium, to high). Because the refuelling in this system is always for 350 bar on-board storage, there is no need for precooling the hydrogen prior to refuelling.

Capital costs

The costs of the cascade storage can reach up to 1000 €/kg according to [h2a], because of the higher pressures it is designed for. It was assumed that the compressors used in the dispensing process were different from the ones used in conditioning, only in size and therefore the equation 34 34343434was used to calculate their cost as well.

A dispenser is also needed, and its cost was estimated at €100,000 for every 400 kg/day [58]. The dispenser is placed indoors and covers no more than 8 m^2 per unit, including a zone around the dispenser that can't be used, for safety reasons and to enable the flow of forklifts when refuelling [65].

Operational costs

Again, the power of the compressors was calculated first, using equations 35 and 36 and setting the variables according to the following:

$$P_{compressor_{in}} = 50\ bar \tag{41}$$

$$P_{compressor_{out}} = \begin{cases} 480 \\ 320 \\ 140 \end{cases} bar \tag{42}$$

$$\dot{m}_{compressor} = \frac{m_{removed}}{10\ minutes} \tag{43}$$

European Emissions Trading System (ETS)

The intent behind hydrogen production using electrolysis, is the decreasing of the emissions associated with its usage that derive from the methane used as feedstock in SMR. However, as shown above, the emissions associated with every kWh of electricity on average in the European Union, result in electrolyser that produce hydrogen that is less environmentally friendly that its SMR counterpart. For this reason, in this study the purchase of Guarantees of Origin (GoO or GOs) were taken under consideration for the production of hydrogen through electrolysis in the cases of on-site and semi-centralised production. These

GoO according to EU legislation, prove that one MWh of electricity was produced using renewable energy sources [66]. Data from [67] was used to assess the added cost to the electricity prices from the GOs. An extra 0.30 €/MWh was considered for the purchase of green electricity.

A share of the hydrogen produced by grid electricity, is renewable. To determine this share, the average share of electricity from renewable energy sources in the country of the hydrogen production or the European Union might be used, according to the Renewables Energy Directive II, article 25c. In either case, an equivalent amount of GOs must be cancelled. In this study, because the model created was meant to be generally applicable to most European countries, GOs for all the MWh of electricity used were assumed to be purchased, even though it probably doesn't help in further increasing the share of renewable hydrogen produced. However, this helps conditioning the model to account for any electricity mix. And because of the very low cost of those GOs, it is the author's belief that it is safe to assume that the impact on the economics is negligible.

However it should be made clear at this point, that the lower carbon footprint of the hydrogen cannot be used for in calculations of the upstream emissions reduction from the refineries, as it is explicitly stated in the Guidance Note [68].

The savings on emissions were calculated using data from [69], where the authors report that every kilogram of SMR hydrogen releases 11,888 g_{CO2}.

Sales of hydrogen

The supply of hydrogen in gaseous form was assumed to take place using tube trailers. The trailers used currently, transport hydrogen at 200 bar with payloads of up to 368 kg. The authors of [54] report a price of 200,000€ including the pressure valves and the chassis. The latter cost was used for the calculations, as well as a capacity factor of 0.75, meaning that only 75% of the hydrogen carried is actually delivered, since the tubes cannot be completely emptied. Therefore the effective payload used in the calculations was 312.8 kg of hydrogen delivered per tube trailer. The trailers are carried by a tractor which was assumed to cost the same cost as a diesel truck, at €80,000.

The tube trailers are filled using a filling skid comprising mostly of compressors. The CAPEX of the filling skid was calculated according to [54].

$$CAPEX_{filling\ skid} = 550{,}000\left(\frac{H_2\ Flow\ rate}{50}\right)^{0.66} + 300{,}000\left(\frac{H_2\ Flow\ rate}{50}\right)^{0.66}\left(\frac{\left(\frac{Pressure_{Out}}{Pressure_{In}}\right)}{\left(\frac{200}{30}\right)}\right)^{0.25}\left(\frac{Pressure_{Out}}{200}\right)^{0.25} \tag{44}$$

To calculate the operational and capital expenditures of the compressors of the skid, the equations provided in *Compressors* were used.

The trucks were assumed to travel from the filling site to the client, unload and return. For the delivery costs the fuel needed to transport the tube trailers was estimated using an average consumption of 30 L /100 km for the tractors with a diesel price of 1.20 €/L. The labour costs for every delivery comprise of the time it takes to travel at an average speed of 15 km/h to the destination, empty the hydrogen to the client's storage and return to the filling site. The trip time obviously depends on the distance of the client from the filling site, but the filling, loading/unloading of the trailer requires a fixed amount of time which was assumed to be 1.5 hours. The time required to fill the hydrogen tubes is not accounted for in the labour costs of the deliver, as it was taken under consideration in the operational expenditures of the filling site.

Logistics of hydrogen delivery

To assess the number of tube trailers and tractors needed, the following equation was used:

$$T = \frac{\sum_i t_i D_i}{16} \tag{45}$$

where:

- t_i = the total time required for the tractor to load the tube trailer, drive to the destination, unload the hydrogen and drive back for every client per delivery.
- D_i = Daily deliveries to the client.
- T= the number of trucks (tube trailer + tractor) needed. This number is then round up to the closest integer to get the minimum amount of trucks needed.

To calculate trucks needed, the worst case scenario was considered, where all the clients require delivery in the same day. A hydrogen supplier might be able to overcome this “delivery overloading” by planning the schedule of the trucks, factoring in the amount of storage a client might own; this, however, falls out of the scope of the current study. As seen in equation 45 the total time needed is divided by 16, as it was assumed that the trucks would run on two 8-hour shifts.

Additional labour was assumed to be required for the filling site. One operator for every shift was included in the calculations. Given the filling skid’s and tube trailer’s assumed design, a 3 hour filling time was used. The filling site operates for 16 hours every day and 2 trucks with tube trailers are needed to facilitate the necessary deliveries.

5 Results

5.1 Introduction

In chapter 5 the results of for every scenario and type of company are presented. For every case, the values for the capital and operational expenses are first shown, followed by a breakdown of the hydrogen cost per kilogram. Then the evaluation of the net present value of each investment is analysed and compared with the other scenarios.

5.2 Base case scenario

5.2.1 Refinery

Capital Costs

For the base case of the refinery the capital costs for the purchasing and installing the steam reformer are presented in Table 5-1.

Table 5-1: Capital costs of the refinery for the base case scenario (SMR)

Cost	Per unit	Total
Reformer cost	€4230/kg_{H2}/day	€ 13,536,000
Installation	12% of equipment costs	€ 1,624,320
Non-equipment	20 % of equipment costs	€ 2,707,200
Total		**€ 17,867,520**

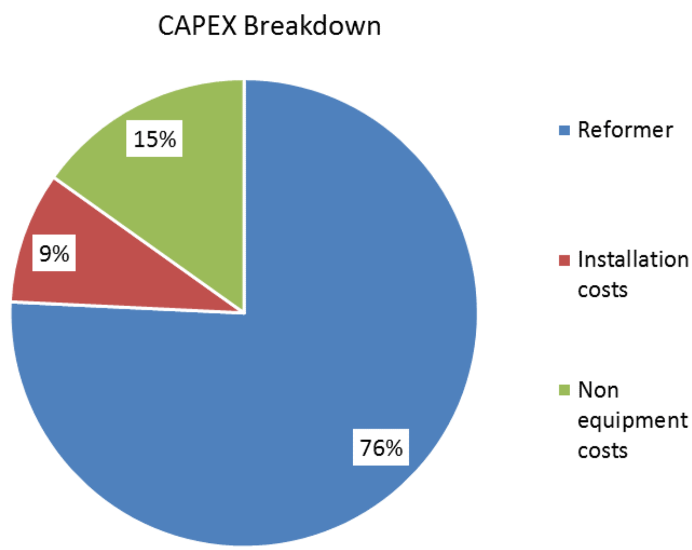


Figure 5-1: Upfront capital costs breakdown for the refinery – base case

The major part of the cost stems from the cost of the SMR equipment with the installation and other non-equipment costs contributing only to a minor extent.

In the case of the SMR, no major repaires/replacements are taken into consideration, like in the case of the electrolysers (that have degrading stacks). The annual maintenance cots (see Table 5-2) includes any necessary repairs that might come up

Operational costs

The operational costs consist of the costs associated with feedstock of the SMR (eg. natural gas for feedstock), its maintenance as well as the costs of the emissions from the hydrogen production from participating in the Emissions Trading System (ETS). The annual OPEX is presented in table.

Table 5-2: Annual operational costs of the refinery for the base case scenario (SMR)

Annual operational costs (€)		
Production costs	1.5 €/kg	€ 1,752,000
SMR maintenance	5 % of CAPEX	€ 338,400
ETS	5.56 € per tonne CO_2	€ 77,202
Total		**€ 2,167,602**

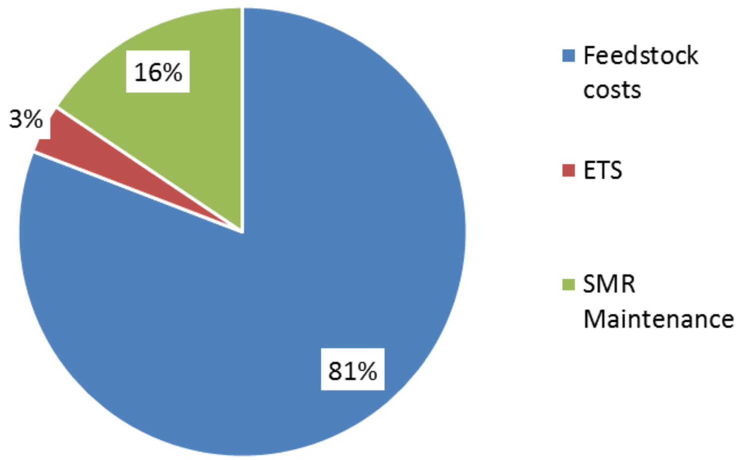


Figure 5-2: Refinery base case OPEX breakdown

The feedstock cost for the H_2 production is the major operational expense at 1.5 €/kg. Maintenance of the reformer is a significant part of the costs at 16%, while the cost for the Emissions Trading System is only a fraction of the total cost, at 3%.

Total hydrogen cost per kg

Total cost of hydrogen in the case of SMR production amounts to 2.62 €/kg. The breakdown of costs is presented in Figure 5-3 below:

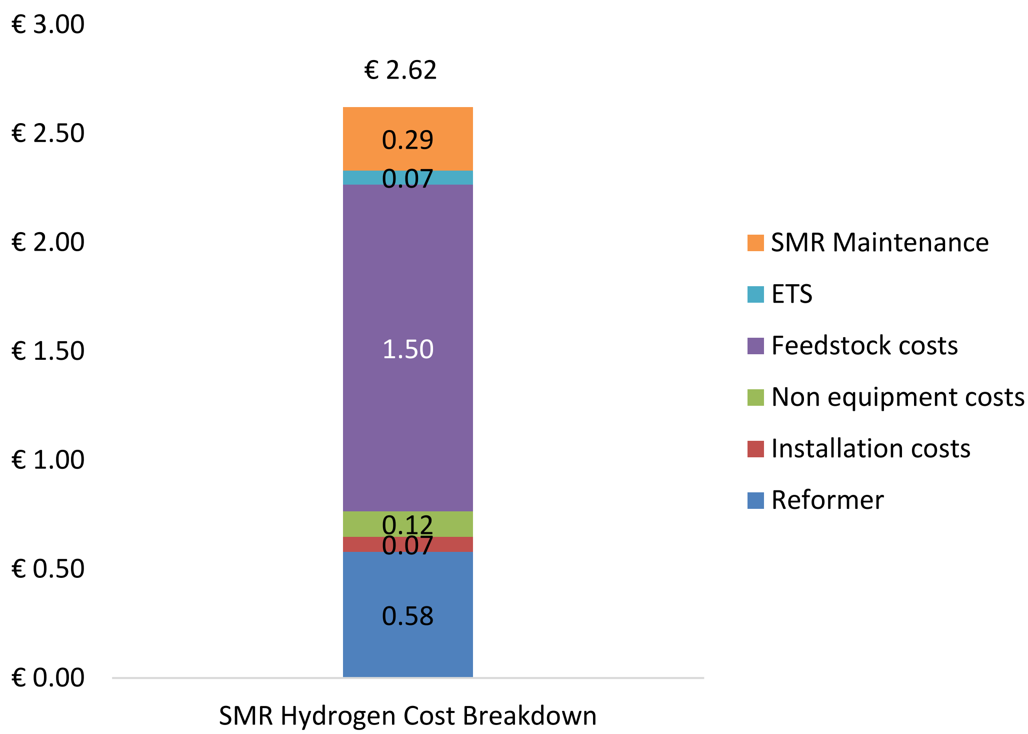


Figure 5-3: Refinery Base case (SMR) H2 cost breakdown

As expected most of the costs of hydrogen derive from the feedstock costs (natural gas), and the reformer cost.

5.2.2 Glass and steel plants

<u>Capital Costs</u>

The capital costs for the glass and steel plants in the base case scenario are the result of the hydrogen storage and its relevant costs (installation and non-equipment costs). As previously explained, in the base case there is no compressor between the truck that delivers the hydrogen and the site storage; hydrogen transfer is a result of the pressure difference and therefore compression costs do not burden the base case scenario. The storage is sized to cover the day to day needs at 400 kg_{H2} and 1400 kg_{H2} for the glass and steel plants and no backup hydrogen storage is considered.

Table 5-3 presents the results for the base case scenario of glass and steel plants.

Table 5-3: Capital costs of the glass and steel for the base case scenario (Delivered H2)

Cost	Per unit	Glass	Steel
Storage cost	€400/kg_{H2} stored	€ 160,000	€ 560,000
Installation	12% of equipment costs	€ 19,200	€ 67,200
Non-equipment	20 % of equipment costs	€ 64,000	€ 224,000
Total		**€ 243,200**	**€ 851,200**

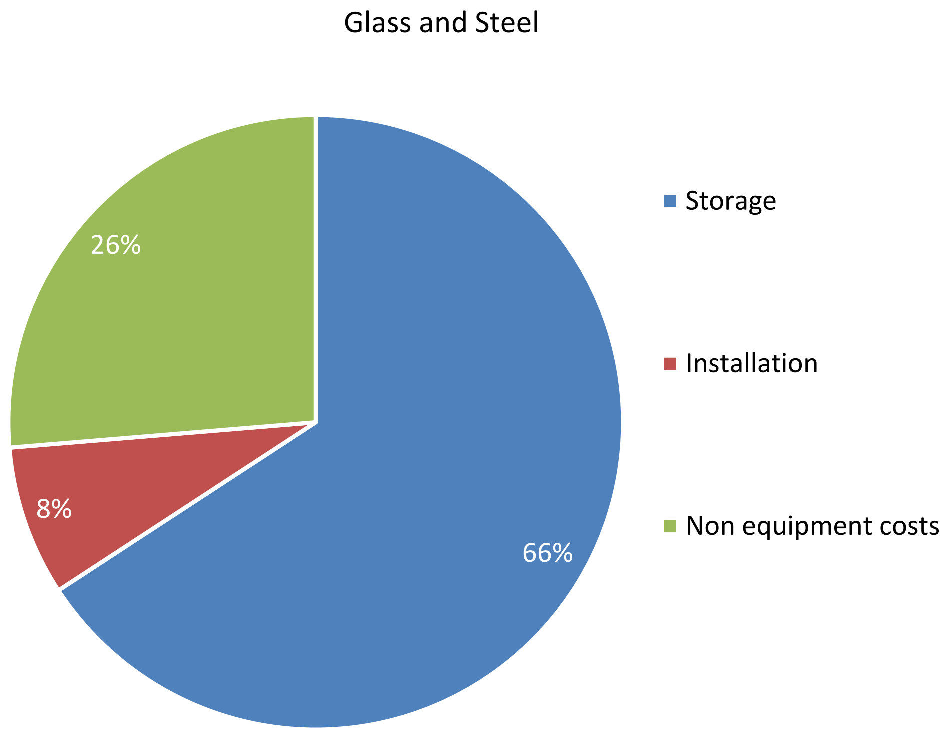


Figure 5-4: Upfront capital costs breakdown for the glass and steel industries – base case

The breakdown of the capital costs is exctly the same for both the glass and steel industries in the base case; the components are exactly the same, different only in size and no economies of scale effect applies to them.

Operational costs:

Using the average price of delivered hydrogen, daily and annual costs for hydrogen supply were calculated and presented in Table 5-4. It is reminded that these values represent the costs "at the gate", before any conditioning and storage of the hydrogen.

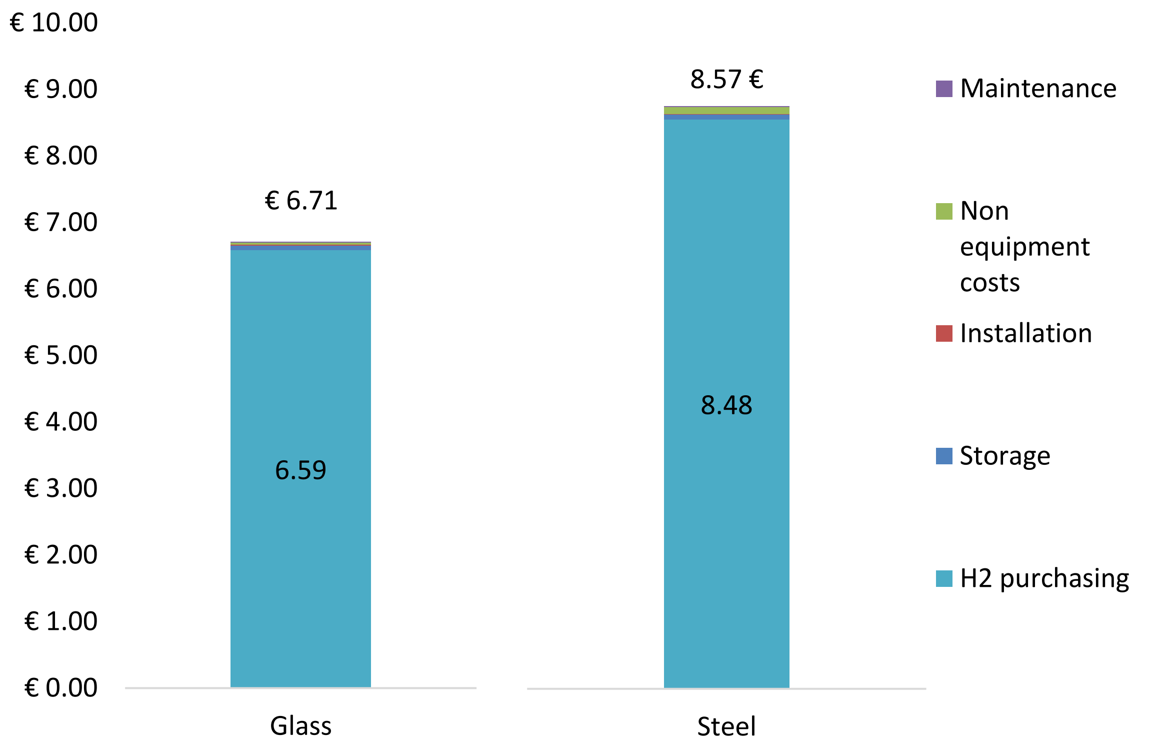
Table 5-4: Annaul operational costs of the glass and steel industries for the base case scenario

Annual operation costs (€/year)		
	Glass	Steel
Storage Maintenance	1,600	5,600
Cost of H_2 delivered	721,331	3,248,044
Total	**722,931**	**2,787,612**

The operational costs are almost completely comprised of the cost of the hydrogen purchasing from the third party vendor.

Total hydrogen cost per kg

Total cost of hydrogen per kg in the case of delivery for glass and steel plants amounts to 6.71 €/kg and 8.57 €/kg, with the major cost being the purchasing cost of hydrogen from the third party vendor.



5.2.3 Forklifts

Capital costs

For the base case scenario of forklifts, the capital costs consist of the the first power units for the lifts – in this case, batteries – along with the chagring and changing equipment necessary.

Table 5-5: Upfront capital costs for the base case scenario of forklifts – 50 battery electric Class I forklifts

	Per unit (€)	Units needed	Total CAPEX for (€)
Battery	5,000	150	750,000
Chargers	2,500	50	125,000
Changing equipment	8,100	4	32,400
Installation costs (excluding batteries)			21,288
Battery room	356 €/lift	1	17,800
Non-equipment costs	40% of equipment cost		370,080
Total	**1,316,304**		
Per lift	**26,326**		

As seen in the table above the capital costs are dominated by the costs of the batteries, representing 68% of the total costs. These are only the *upfront* battery costs, not including the purchasing of further batteries as replacements that are included in the OPEX analysis below, as they take place further down the life of the project.

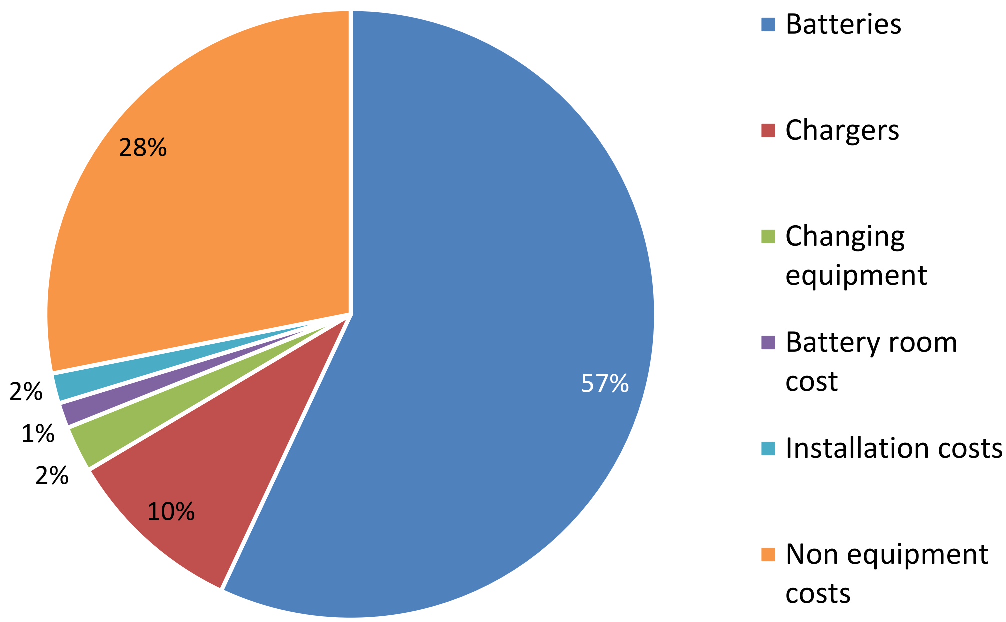


Figure 5-5: Upfront capital costs breakdown for the forklifts fleet – base case

Operational costs

The operational costs only consist of the charging of the batteries, the regular maintenance and the labour costs associated with their changing throughout the day. Also, their replacement costs are included as cash outflows, every five years.

Table 5-6: Annual operational expenses of the forklift fleet for the base case (battery electric)

Annual operational costs (€)		
	Cost per unit	Total
Battery maintenance	1,620 €/year/battery	€243,000
Electricity consumption (battery charging only)	0.070 €/kWh	€130,536
Labour (battery changing)	17.57 €/hour	€228,600
Total		**€ 602,136**
Per lift		**€ 12,042**

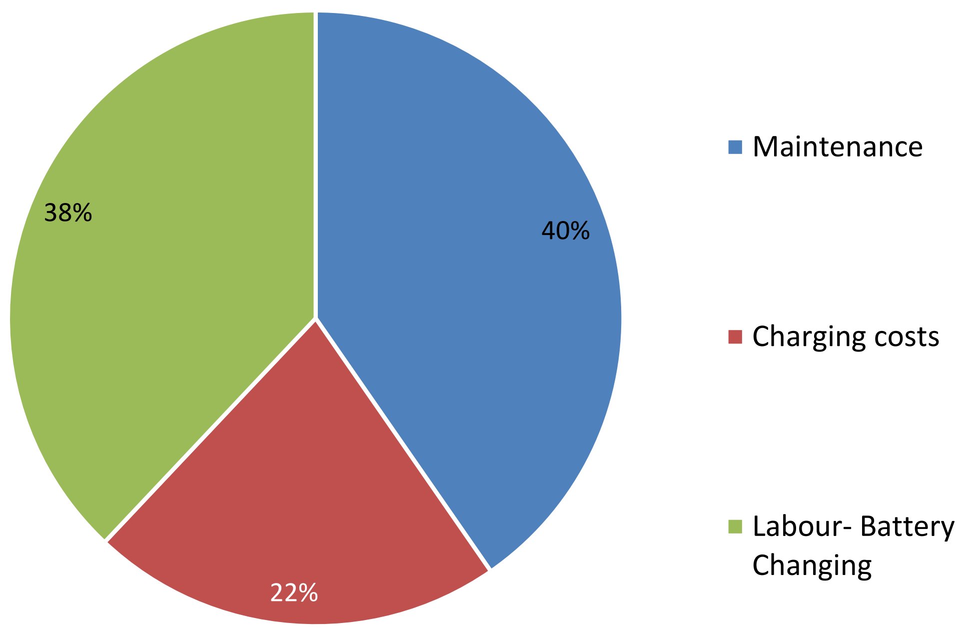


Figure 5-6: Operational costs of the forklifts breakdown for the base case scenario

Infrastructure replacement costs

Infrastructure replacement costs occur every 5 for the batteries and every 10 years for the chargers. No components of the bare forklifts or the changing equipment were taken into account.

Table 5-7: Replacement costs for the battery electric forklift case

Replacement costs			
	Period (years)	Cost for every replacement	Total over investment's lifetime
Batteries	5	€750,000	€1,500,000
Chargers	10	€25,000	€125,000
Total		**-**	**€1,625,000**
Per lift		**-**	**€32,500**

These costs however must be discounted to their present value since they take place over a rather long period of time to be correctly evaluated. This is discount is included in the net present value calculations, presented later on.

5.2.4 Vans and trucks

<u>Capital costs</u>

The transportation company's capital cost for the base case, includes the costs of acquiring the vehicles without any further equipment, since the refuelling is not done on-site, but rather in a conventional fuel station. Any other capital costs, are thought to be common between fuel cell and internal combustion vehicles, and therefore not considered. The costs for purchasing the ICE vehicles are presented in Table 5-8.

Table 5-8: Capital costs, base case scenario for vans and trucks

	Per unit (€)	Vehicles	Total CAPEX (€)
Vans	34,000	50	1,700,00
Trucks	80,000	50	4,000,000
Total			**5,700,000**

Of course the most expensive part of the capital costs is the purchase of the heavy trucks with more than double the capital costs of the vans.

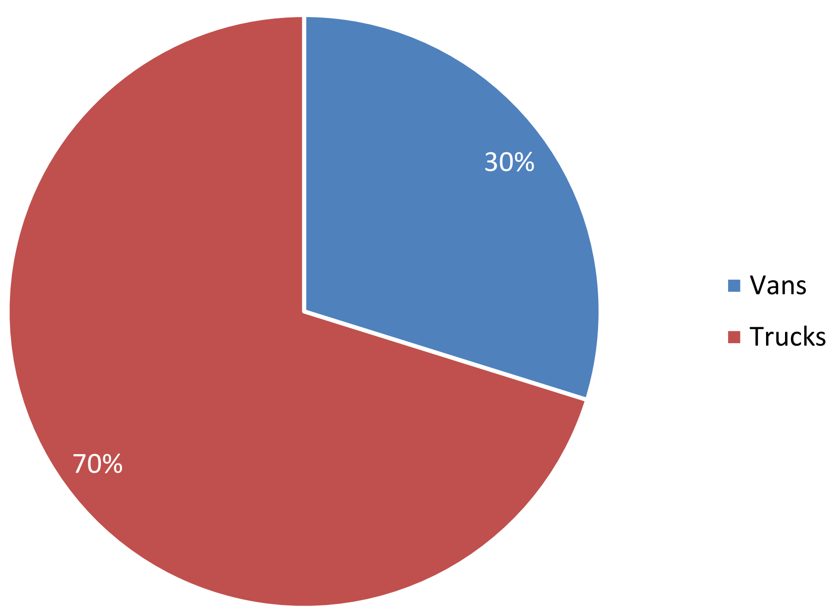


Figure 5-7: Upfront capital costs breakdown for the vans and trucks fleet – base case:

<u>Operational Costs</u>

To calculate the operational costs for vans and trucks, the maintenance costs were taken into account and of course the fuel costs for the 100 km and 250 km per day trips of the vans and trucks, respectively.

Table 5-9: Annual diesel costs for vans and truck

	Diesel Consumption	
	L/100km	Total Cost (€/year/fleet)
Vans	10	204,000
Truck	36	1,836,000
Total		**2,040,000**

Table 5-10: Annual maintenance costs for diesel vans and trucks

	Maintenance	
	Cost (€/km)	Total Cost (€/year/fleet)
Vans	0.06	102,000
Trucks	0.09	382,500
Total		**484,500**

Fuel costs contribute the most in the operational expenses and specifically the costs to refuel the trucks. As shown in Figure 5-8, 73% of the annual expenses are just for the refuelling of the trucks.

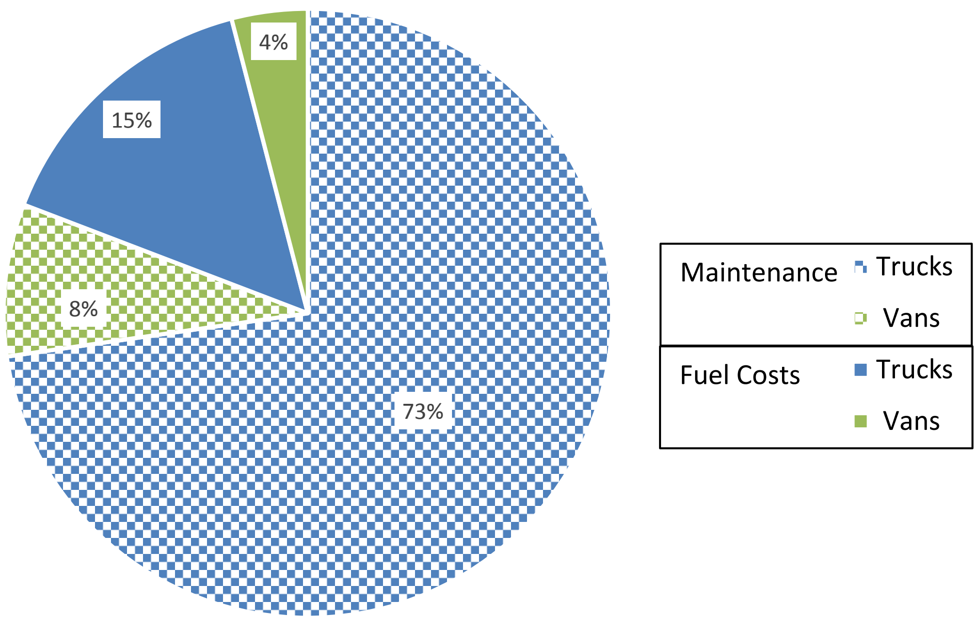


Figure 5-8: Operational costs of the vans and trucks breakdown for the base case scenario

Infrastructure replacement costs

It was assumed that the vehicles are replaced every 10 years and therefore only one replacement for both types occurs during the analysed period. The replacements costs are at 100% of the original CAPEX since no cost reduction were assumed in the following years for the already technologically mature internal combustion vehicles.

Table 5-11: Replacement costs for the diesel trucks and vans case

Replacement costs (€)			
	Period (years)	Cost for every replacement	Total over investment's lifetime
Vans	10	1,700,000	1,700,000
Trucks	10	4,000,000	4,000,000
Total			**5,700,000**

5.3 On-site production scenario

5.3.1 Refinery

<u>Capital Costs</u>

For the refinery costs, in the on-site scenario, are distinguished between ALK and PEM scenarios.

Table 5-12: Upfront capital expenses of the refinery for the on-site scenarios

		Capital cost for refinery (€)	
		PEM	ALK
Installed Capacity (MW)		10.67	9.07
Electrolyser	€ per kW	1,247	826
	Total	13,301,749	7,487,501
Storage Compressor		0	651,046
Storage Tank		384,000	1,200,000
Installation		1,642,290	1,022,706
Non-equipment		5,474,299	3,409,018
Total		**20,802,339**	**12,954,271**

The values of Table 5-12, show significantly increased costs of the PEM technology electrolyser, with about 60% additional costs over the ALK case. However, the contribution to the costs is rather similar in both cases, evident from the charts of Figure 5-9.

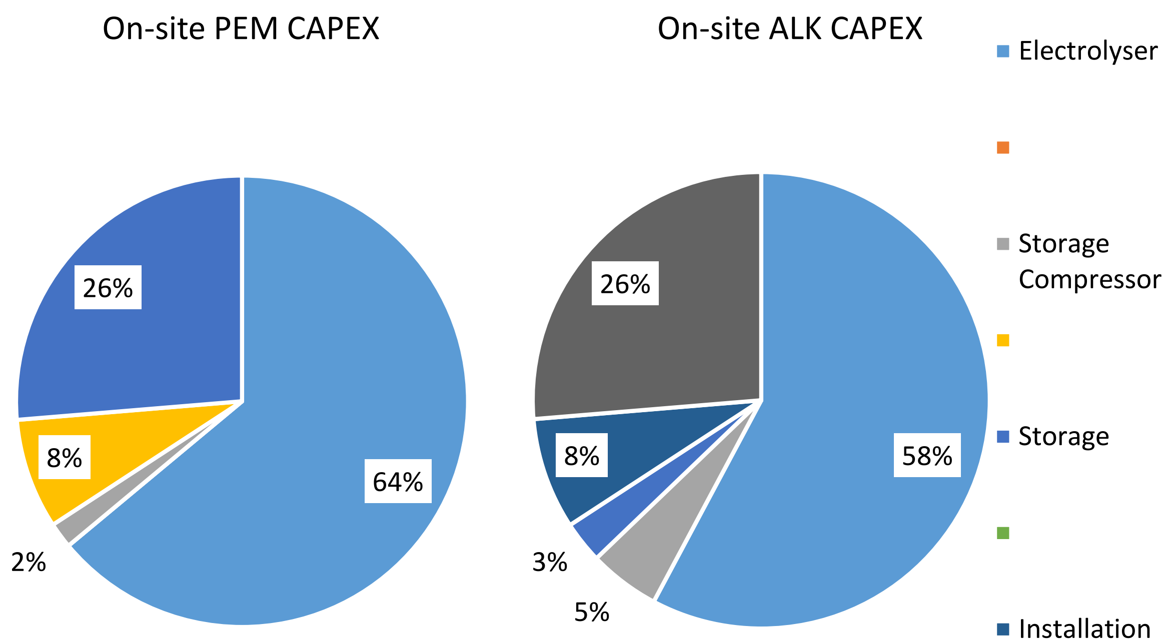


Figure 5-9: Upfront capital costs breakdown for refinery: PEM and ALK electrolysers

The PEM electrolyser has higher capital costs due to the higher specific cost (€/kW), as it is an inherently more expensive technology and it is still in early commercial stages. The big advantage of PEM electrolysis, electrochemical pressurisation of the produced hydrogen, resulting in greater output pressure and reducing the need for mechanical compression, apparently is not enough to offset the high capital costs.

Operational Costs

The operational costs consist mainly of the electricity costs, used by the compressor and the electrolyser and also of the maintenance costs of these components and the labour costs involved in their operation.

Table 5-13: Annual operational expenses of the oil refinery for the on-site production scenarios

		PEM	ALK
Maintenance	Compressor	0	38,664
	Electrolyser	665,087	372,501
	Storage	3,840	12,000
Electricity	Storage Compressor	0	164,265
	Electrolyser	3,525,024	2,982,713
Labour		99,763	99,763
Total		**4,359,739**	**4,212,217**

Overall, the operational costs of the PEM electrolyser are only slightly higher than the equivalent costs of an ALK electrolyser, unlike the massive difference in capital costs. These cost lead to a cost of 4.61 €/kg for the PEM electrolyser and 3.63 €/kg for the ALK.

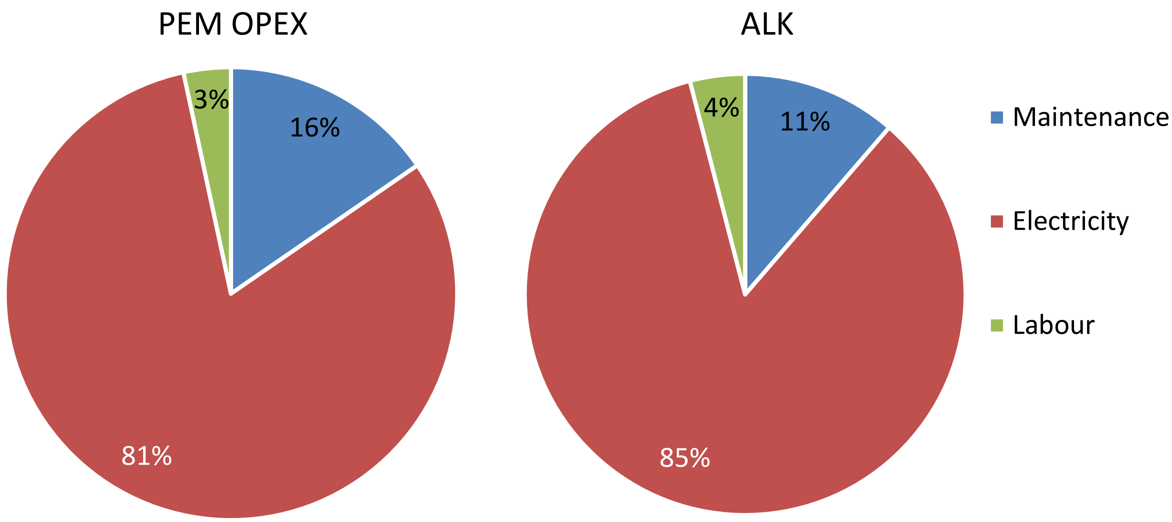


Figure 5-10: Operational costs of the refinery breakdown for the on-site scenarios

Replacement costs

The electrolyser stacks needs replacement after 10 years and they were assumed to cost 30% of the original CAPEX of the electrolyser.

Therefore in year 10, an additional cash outflow occurs, that has to be considered in the calculation of the discounted costs of the investment.

Table 5-14: Refinery's replacement costs of electrolysers for on-site scenarios

Replacement costs			
	Period (years)		Cost for every replacement (€)
Electrolyser stacks	10	PEM	3,990,525
		ALK	2,246,250

Hydrogen cost breakdown

To better understand these costs, the produced hydrogen cost is broken down to its basic components. It can be seen in Figure 5-11 that electricity in both cases is the most important factor to the final cost.

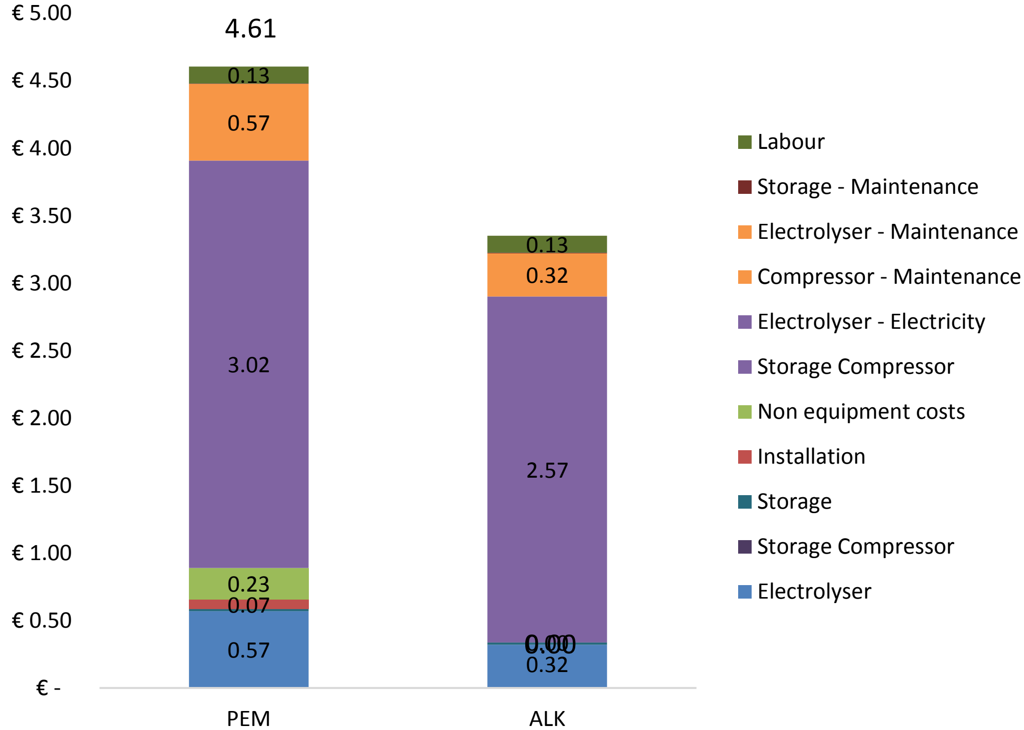


Figure 5-11: Hydrogen cost breakdown per kilo of PEM and ALK for on-site production in the model's refinery

The hydrogen costs are mainly driven up by the electricity required by the electrolyser, making the PEM hydrogen significantly more expensive, because of the PEM's lower efficiency. These results also state the importance of efficiency, since these electrolysers are fed with low-cost electricity and still from the electric energy consumed *alone* the costs are almost double than the equivalent SMR.

Comparison with the base case scenario

Comparing the on-site production by electrolysis to the base case scenario, shows that the marginal cost of P2H hydrogen, is 1.5-2 times more expensive than methane hydrogen and therefore the only major cost factor that needs to be reduced, is the price of electricity.

The present value of the costs of the different investments for the P2H cases, show the same trend, with the investment in PEM electrolyser essentially a loss of more than 50 million.

Table 5-15: Net Present Values of investing in PEM or ALK electrolysers - refinery

Net Present Values of costs in € (millions)			
Discount rate: 5.00%	Base Case	PEM	ALK
NPV	44.8	77.3	59.5
Cost difference from base case	-	+72.33%	+32.52%

The savings from ETS (Emissions Trading System) calculated above were obviously not enough to mediate the very high costs of production, especially the electricity costs from the electrolysers operation.

5.3.2 Glass and steel

Capital Costs

Glass and steel industries follow the cost structure of the refinery. The costs of the two investment options for each type of company are shown in tables Table 5-16 Table 5-17.

Table 5-16: Steel industry's electrolyser costs (for ALK & PEM)

		Capital cost for steel (€)	
		PEM	ALK
Installed Capacity (MW)		3.50	2.98
Electrolyser	€ per kW	1,356	956
	Total	4,745,097	2,843,969
Storage Compressor		0	312,031
Storage Tank		1,120,000	1,120,000
Installation		703,812	513,120
Non-equipment costs		2,346,039	1,710,400
Total		**8,914,948**	**6,499,519**

Table 5-17: Glass industry's electrolyser costs (for ALK & PEM)

		Capital cost for glass (€)	
		PEM	ALK
Installed Capacity (MW)		1.00	0.96
Electrolyser	€ per kW	1,489	1,168
	Total	1,489,300	985,891
Storage Compressor		0	136,494
Storage Tank		320,000	320,000
Installation		217,116	173,086
Non-equipment costs		723,720	576,954
Total		**2,750,136**	**2,192,425**

As with the refinery, the PEM option requires higher capital costs in both steel and glass manufacturing. In fact investment in PEM electrolysers costs about 25% more than ALK in upfront capital for the glass industry and 37% more for the steel industry. Considering also the 60% difference between PEM and ALK in the refinery case, it can be concluded that the gap between the two electrolyzing technologies becomes larger as the daily production increases.

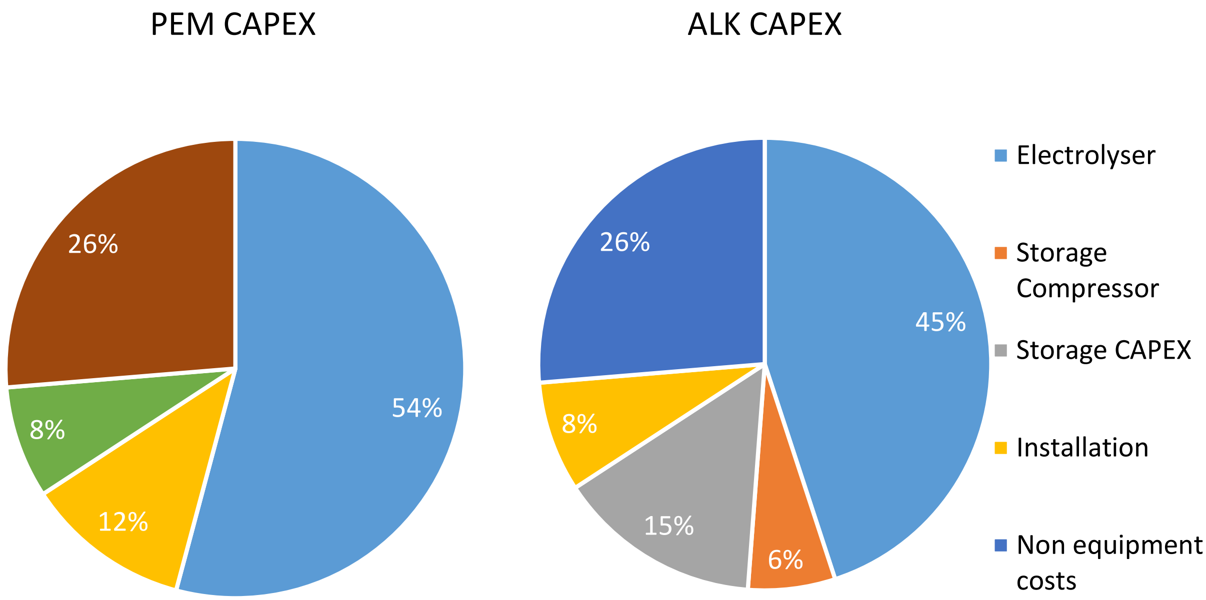


Figure 5-12: Glass - Cost breakdown of upfront capital costs for on-site scenarios

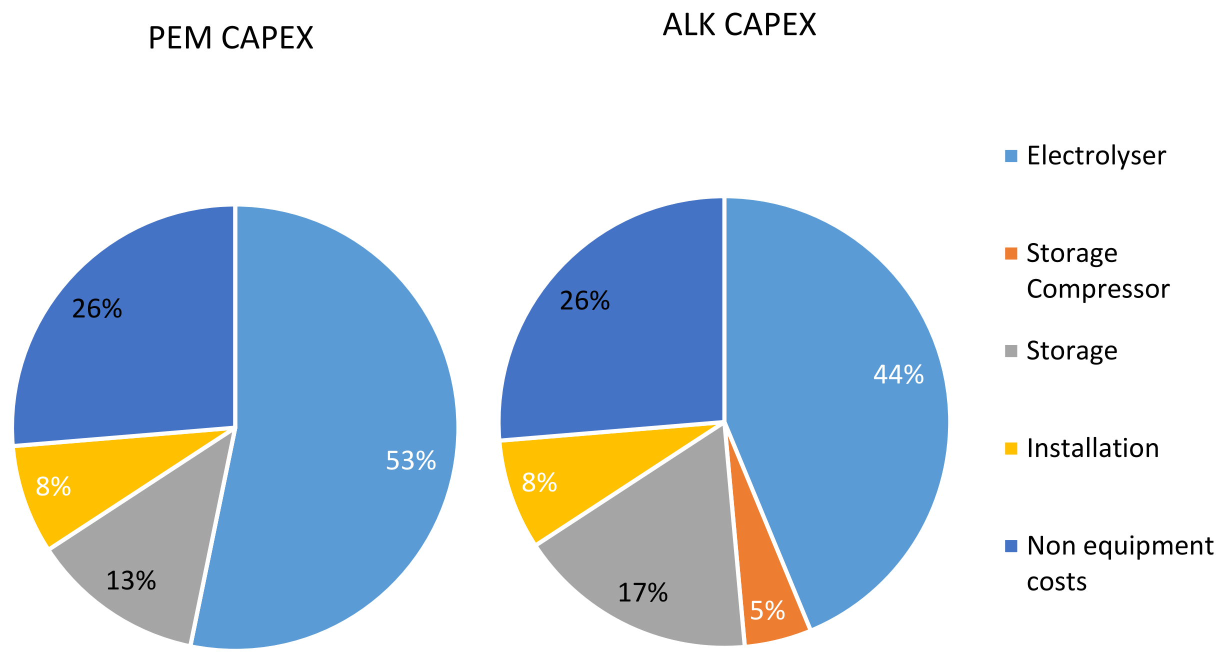


Figure 5-13: Steel - Cost breakdown of upfront capital costs for on-site scenarios

Operational costs

The operational costs consist of the electricity costs for the compressor and electrolyser operation and the maintenance for these components and labour involved in their operation.

Table 5-18: Glass plant's annual OPEX per category and electrolyser type

Annual operation expenses (€/year)			
		PEM	ALK
Maintenance	Compressor	0	6,825
	Electrolyser	74,465	49,295
	Storage	3,200	3,200
Electricity	Compressor	0	10,881
	Electrolyser	555,822	469,182
Total		**633,487**	**626,022**

Table 5-19: Steel plant's annual OPEX per category and electrolyser type

Annual operation expenses (€/year)			
		PEM	ALK
Maintenance	Compressor	0	15,620
	Electrolyser	237,255	142,198
	Storage	11,200	11,200
Electricity	Compressor	0	33,608
	Electrolyser	1,501,574	1,276,337
Total		**1,750,028**	**1,704,181**

Again, the ALK electrolyser proves to be more economical, although the cost differences are minor between the two. The lower electricity costs from the improved efficiency of the ALK are almost diminished from the added costs of compression.

Hydrogen cost breakdown

Figure 5-14 and Figure 5-15 present the hydrogen cost breakdown for glass and steel companies and show the same trend as in the case of the refinery, where the electricity demand of the electrolyser is the main contributor to the cost of hydrogen.

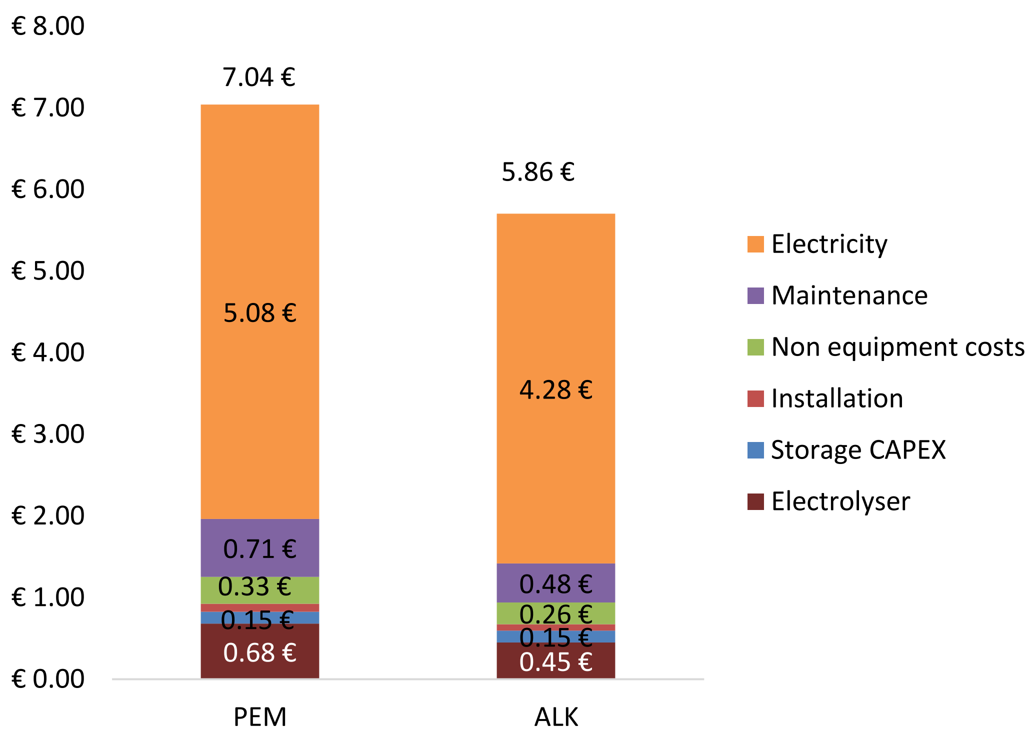


Figure 5-14: Glass - hydrogen cost breakdown per kg for on-site scenarios

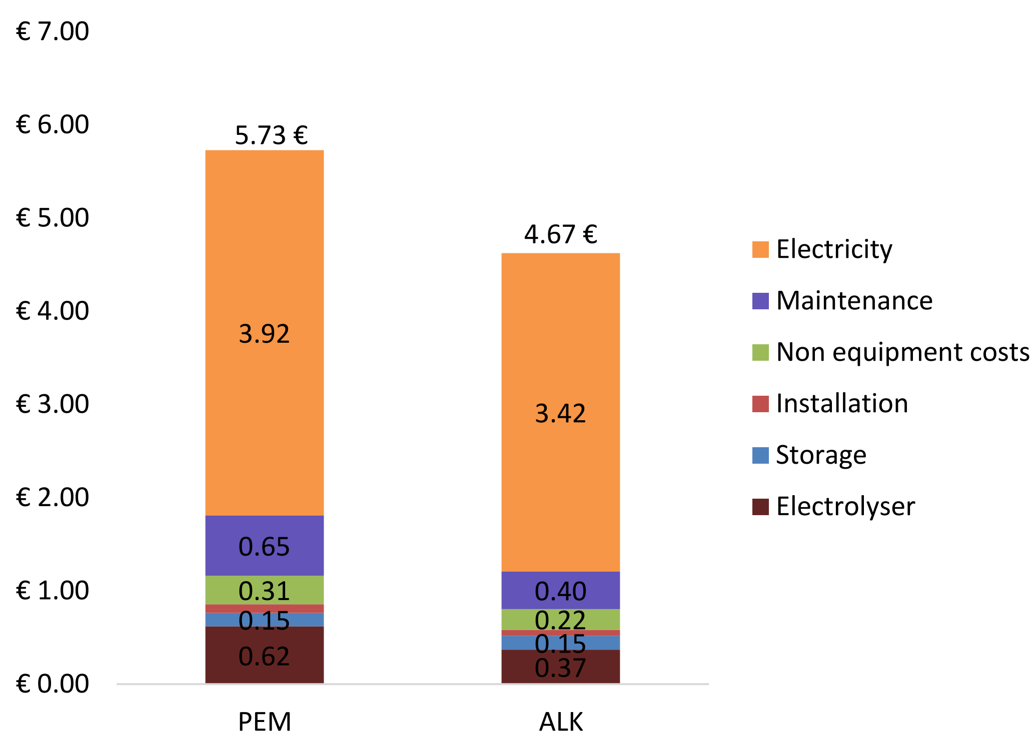


Figure 5-15: Steel - hydrogen cost breakdown per kg for on-site scenarios

Comparison with the base case scenario

When comparing the hydrogen cost per kg for the three scenarios so far, on first sight the on-site production seems to be a good investment for both industries, especially for the ALK type electrolysers. The costs/kg are greatly reduced in the case of the steel industry, however to accurately compare, the discounted cash flows for lifetime of the projects must be taken into account

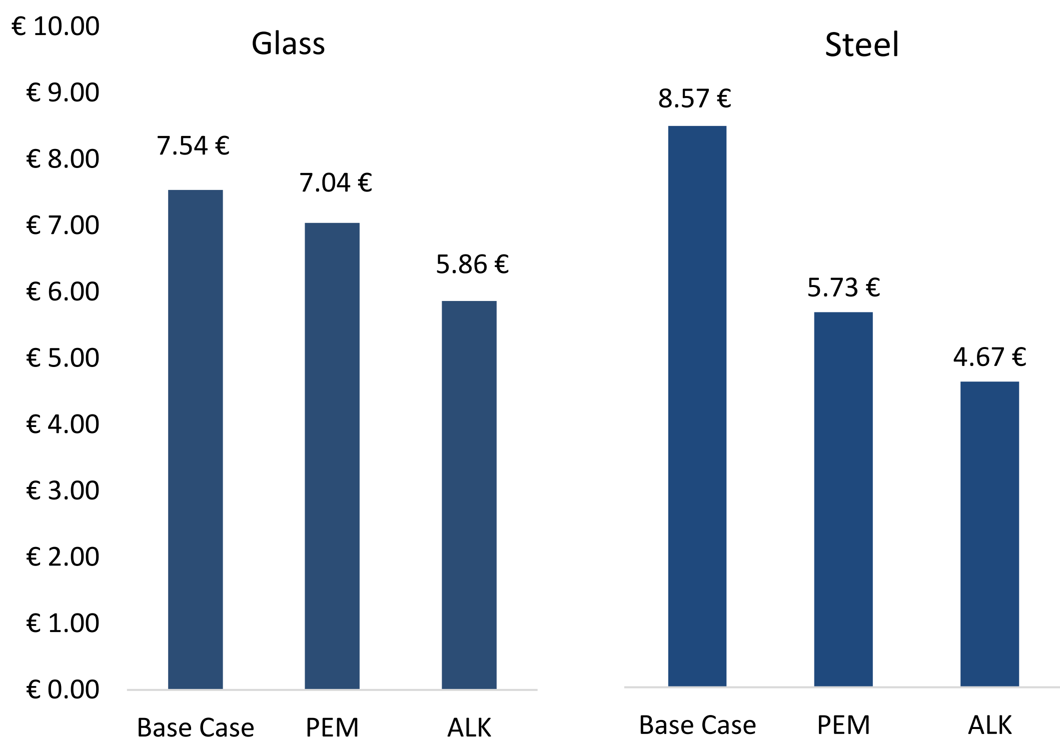


Figure 5-16: Hydrogen cost per kg comparison - base case and on-site scenarios

Tables Table 5-20 Table 5-21 below present the net present value of all costs throughout the 20 years of the projects, taking into account the replacements of the stacks of the electrolysers in Year 10.

Table 5-20: Net Present Values of investing in PEM or ALK electrolysers - glass

Net Present Values of costs in € (millions)			
Discount rate: 5.00%	Base Case	PEM	ALK
NPV	€ 9.2	11.0	1.2
Cost difference from base case	-	+ 20 %	+ 11 %

Table 5-21: Net Present Values of investing in PEM or ALK electrolysers - steel

Net Present Values of costs in € (millions)			
Discount rate: 5.00%	Base Case	PEM	ALK
NPV	41.3	32.0	28.5
Cost difference from base case	-	- 23 %	- 31 %

Glass manufacturers (or in fact any industry) with hydrogen demands close to 300 kg/day, will not in fact have financial benefits from installing an electrolyser on their site, however the cost in the case of the ALK electrolyser, is not prohibiting, especially if some costs reductions in electricity or non-equipment costs are made. For larger demands however, like the case of the systems steel manufacturer, the benefits of installing electrolysis units are obvious with a reduction in costs of up to 31% over 10 years.

5.3.1 Forklifts

Capital Costs

The costs of hydrogen production (electrolyser, compression) and dispensing needs (cascade compressor, cascade storage, dispenser) as well as the purchase of the fuel cell stacks for the forklifts were calculated based on the fleet size and its energy needs. The upfront capital costs, are presented in table Table 5-22.

Table 5-22: Capital cost for the forklift fleet, on-site production scenario

		Upfront capital costs – forklifts (€)	
		PEM	ALK
Installed Capacity (MW)		0.90	0.77
Fuel cell modules		1,400,000	
Electrolyser	€ per kW	1,501	1,186
	Total	1,351,004	907,573
Compressor	Low pressure	112,938	151,230
	Cascade	234,898	382,555
Storage	Low pressure	288,000	
	Cascade	21,600	
Dispenser		90,000	
Installation		251,813	198,601
Non-equipment costs		839,376	662,004
Total		**4,628,911**	**4,183,638**

The upfront capital costs are greatly increased in the case of both PEM and ALK scenarios due to the cost of the electrolysers and the fuel cell modules for the forklifts, resulting in 3.5 and 3 times higher upfront costs compared to the base case.

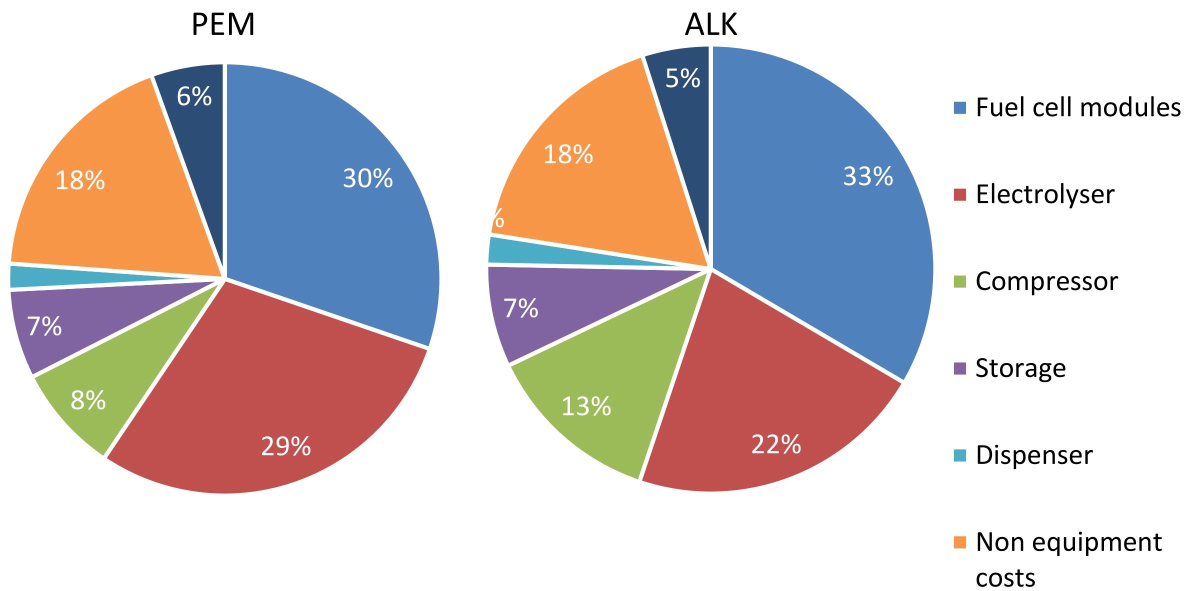


Figure 5-17: Cost breakdown of upfront capital costs of the forklifts for on-site scenarios

As shown in Figure 5-17 the non-equipment costs and installation costs are also an important factor, besides the obvious costs of equipment (electrolyser and fuel cells)

<u>Operational costs</u>

The operational costs in the cases of on-site production as with the glass and steel examples, consist mainly of the electricity cost for the hydrogen production, with the maintenance of the fuel cell module coming second.

Table 5-23: Annual operational expenses of forklift fleet for the on-site production scenarios

		Annual operational costs (€)	
		PEM	ALK
Maintenance	FC modules	100,000	
	Compressors (both)	18,684	20,599
	Electrolyser	67,550	45,379
Electricity	Compressors (both)	6,911	12,632
	Electrolyser	272,160	231,336
Labour (refuelling)		76,200	
Total		**541,506**	**486,145**

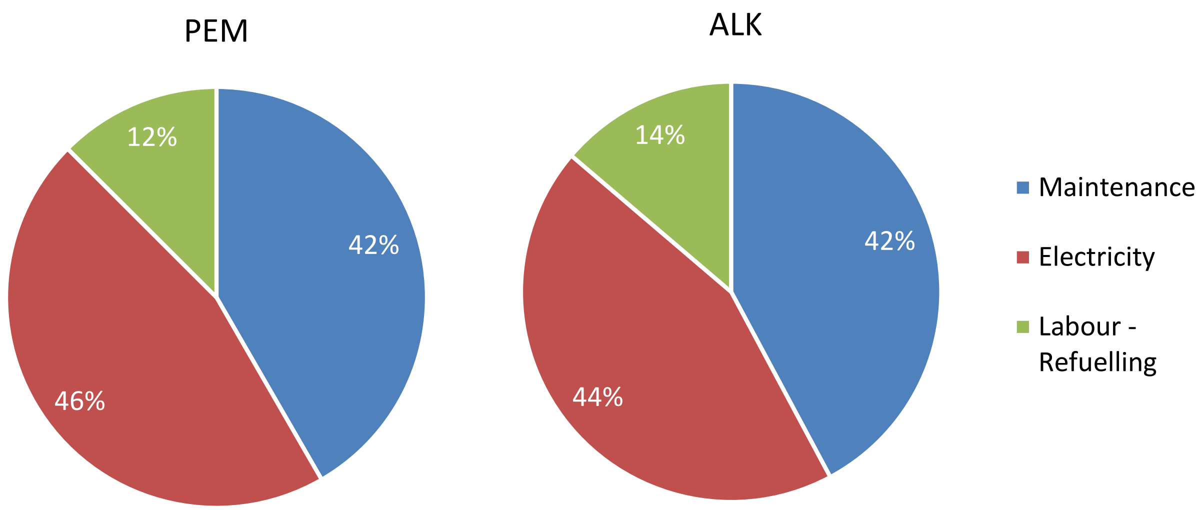


Figure 5-18: Operational costs of the forklifts breakdown for the on-site scenarios

Hydrogen cost breakdown

The hydrogen cost presented in Figure 5-19 was calculated using only the upfront capital and annual operational costs associated with the production of the hydrogen, and as such, does not include the costs of the fuel cell modules for the forklifts, or future replacement costs for fuel cells or electrolysers.

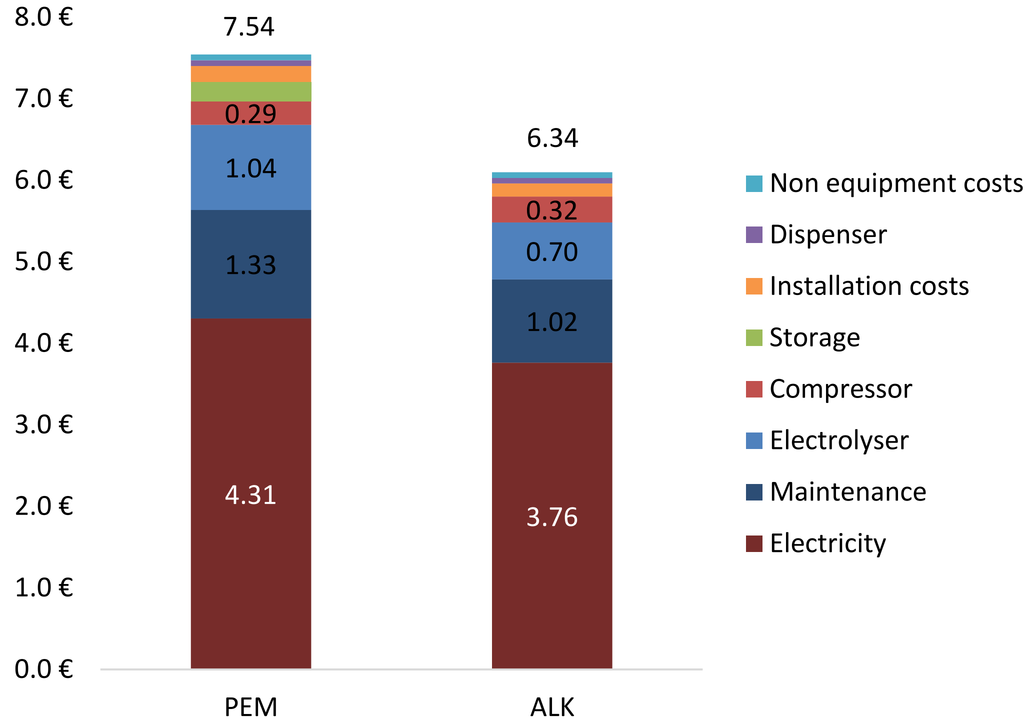


Figure 5-19: Hydrogen cost per kg breakdown for on-site scenarios for forklifts

Comparison with the base case

In Table 5-24 the net present values of all the costs are presented for the forklifts fleet for the base case and on-site production scenarios. All the cash flows during the 20 year lifetime of the project are considered in these calculations.

Table 5-24: Comparison with the base case scenario - Forklifts

Net Present Values of costs in € (millions)			
Discount rate: 5.00%	Base Case	PEM	ALK
NPV	13.0	12.6	11.1
Cost difference from base case	-	- 2 %	-13 %

As shown above, both P2H scenarios result in overall cost reductions for the logistics company, with the ALK scenario reaching 15% saving over 20 years.

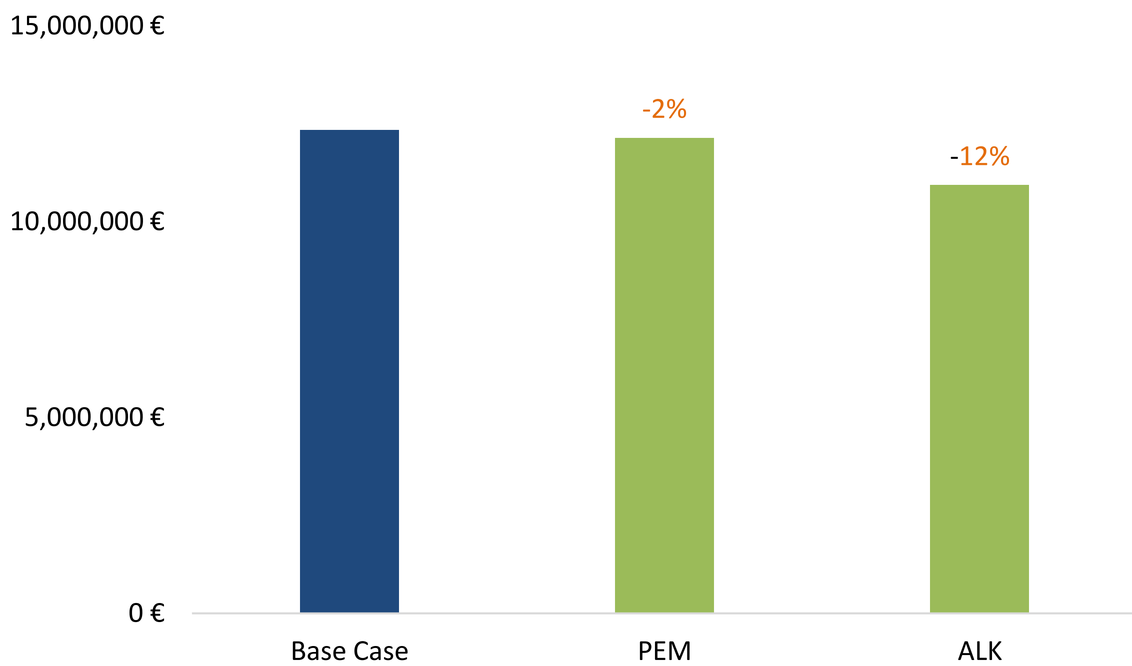


Figure 5-20: Net present values of all cash flows over 20 years for forklift scenarios

5.3.2 Vans and trucks

Capital costs

The transportation company's capital cost for the on-site scenarios case, includes the costs of acquiring the fuel cell vehicles as well as hydrogen production, storage and dispensing equipment, since the refuelling is done on-site. The costs for purchasing the FCEVs and related equipment are presented in Table 5-8.

The costs for acquiring a fleet of identical carrying capacity triples from the base case scenario, as no external government funding is considered.

Table 5-25: Capital costs for both on-site scenarios for vans and trucks

		Upfront capital costs – vans and trucks (€)	
		PEM	ALK
Installed Capacity (MW)		0.90	0.77
Vans		5,100,000	
Trucks		12,000,000	
Electrolyser	€ per kW	1,353	951
	Total	4,884,969	3,347,761
Compressor	Low pressure	282,571	378,376
	Cascade	587,714	
Storage	Low pressure	198,588	
	Cascade	60,000	

Dispenser(s)	270,000	
Installation	754,061	581,093
Non-equipment costs	2,513,537	1,936,976
Total	**26,651,439**	**24,460,508**

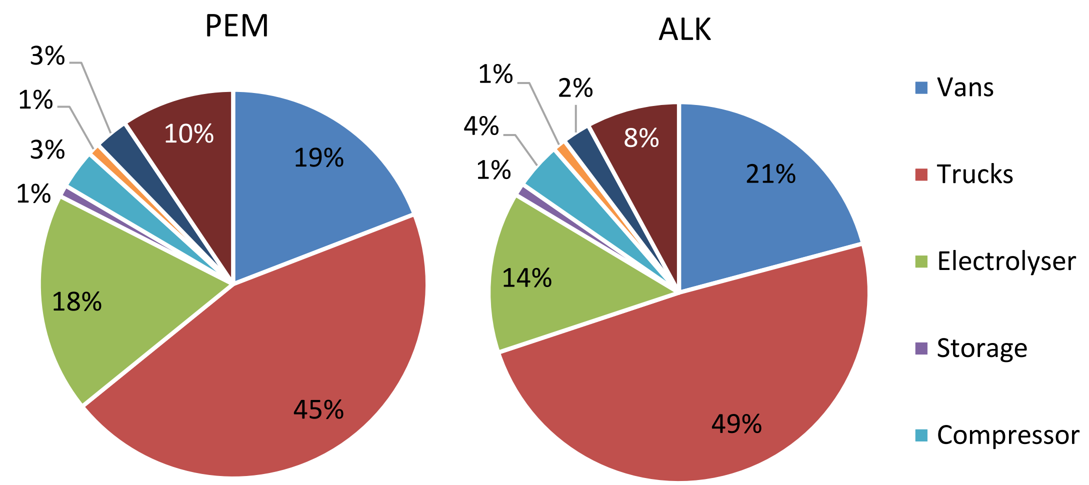


Figure 5-21: Upfront capital costs breakdown for the vans and trucks fleet – on-site production scenarios

<u>Infrastructure replacement costs</u>

It was assumed that the vehicles are replaced after 10 years and therefore only one replacement for both types occurs during the analysed period. The replacements costs for the vehicles are at 50% of their original value, as it is expected that the costs will be brought down by that time. For the electrolysers, the same assumptions made for the other industries are used.

Table 5-26: Replacement costs for the diesel trucks and vans case

	Replacement costs (€)	
	PEM	ALK
Vehicles	8,550,000	
Electrolyser	1,465,491	1,004,328

<u>Operational Costs</u>

To calculate the operational costs for vans and trucks, the maintenance costs were taken into account and of course the fuel costs for the 100 km and 250 km per day trips of the vans and trucks, respectively.

Table 5-27: Annual operational costs of the vans and trucks for the on-site scenarios

		Annual operational costs (€)	
		PEM	ALK
Maintenance	Vans and Trucks	161,500	

	Compressors (both)	244,248	167,388
	Electrolyser	67,550	45,379
	Storage (both)	2,586	
Electricity	Compressors (both)	49,018	81,537
	Electrolyser	1,547,238	1,315,152
Labour (refuelling)		76,200	
Total		**2,048,104**	**1,776,468**

The electrolyser electricity costs overshadow every other cost as has been the case with the other businesses. Overall the difference between the two electrolysis technologies is not that significant for the case of a van/truck fleet.

Hydrogen cost breakdown

The hydrogen costs presented in Figure 5-22 display the importance of the electricity costs once more to the viability of on-site hydrogen production scenarios.

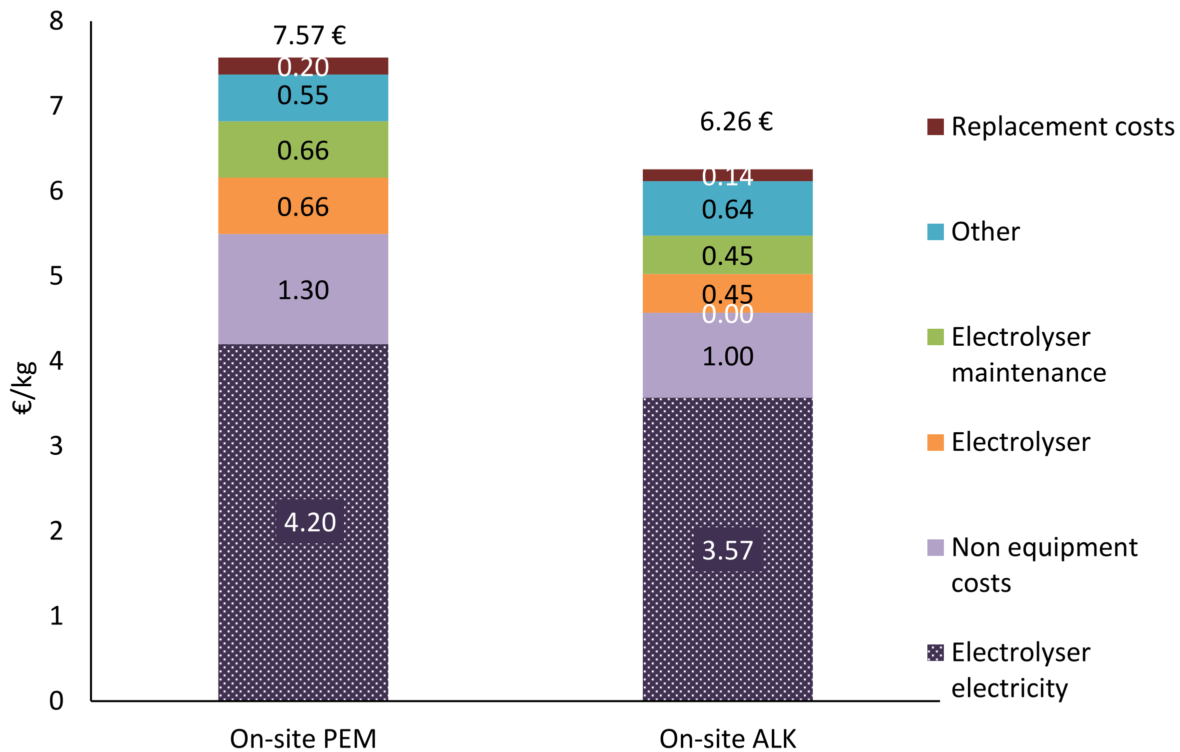


Figure 5-22: Hydrogen cost per kg breakdown for on-site scenarios for vans and trucks

5.4 Semi-centralised scenario

5.4.1 Refinery

<u>Capital Costs</u>

Using the data and assumptions noted in *Electrolysers, Compressors* and *Sales of hydrogen*, the following CAPEX was calculated. The capital expenditure for the production of the hydrogen is not identical to the on-site production case; the electrolyser needs to be increased in size to accommodate the additional needs by the system other industries.

For the semi-centralised scenario only an alkaline electrolyser was considered, as it is the one that can provide lower costs. In addition in such large facility with continuous operation the advantages of the PEM electrolyser would not be as significant as in smaller plants.

Table 5-28: Upfront capital costs of the refinery (for the production part) for the semi-centralised production case

Capital cost for refinery (€)		
		Semi-central (ALK)
Installed Capacity (MW)		10.67
Electrolyser	€ per kW	€ 736
	Total	11,960,390
Storage Compressor		957,052
Storage Tank		384,000
Installation		1,596,173
Non-equipment costs		5,959,046
Total		**20,856,661**

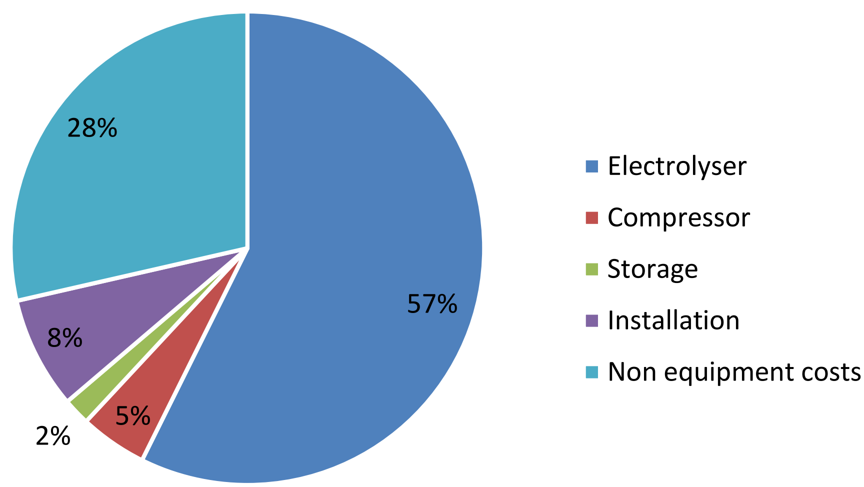


Figure 5-23: Upfront capital cost breakdown of hydrogen production for the semi-centralised scenario

As with all the other P2H scenarios the electrolyser is the most expensive part of the capital costs.

The filling site was assumed to have a capacity of 5 tube trailers per day, which corresponds to a 90 kg/h filling site. The storage is sized for 2 days of additional backup; that means operations can continue normally for 2 days even if the electrolyser is down due to maintenance or unexpected breakdown. One truck and one tube trailer was assumed.

Table 5-29: Capital costs required for H_2 sales (filling skid, tube trailers, storage)

Filling site and delivery vehicle capital costs	
	Cost (million €)
Storage	1,833,041
Filling skid	1,279,672
Tube trailer and trucks	280,000
Installation and non-equipment costs	373,526
Total	**3,766,239**

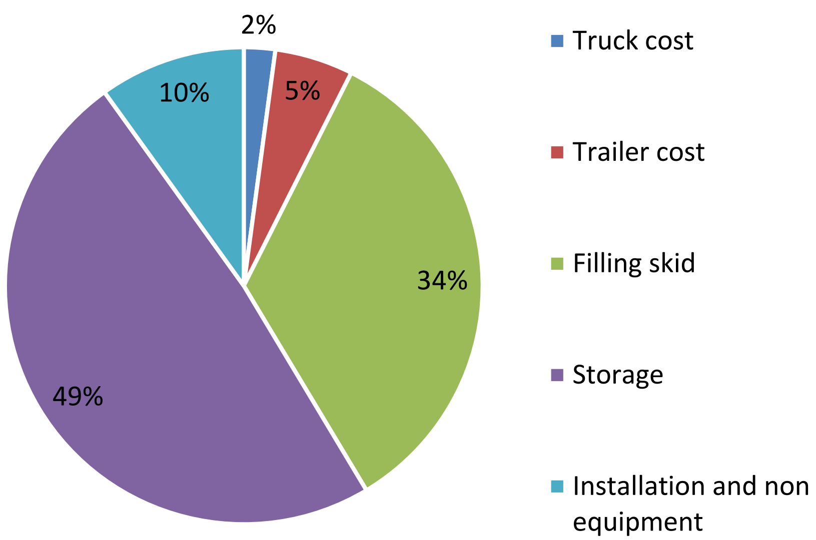


Figure 5-24: Upfront capital cost breakdown the filling site for the semi-centralised scenario

The storage tanks of the filling site are the most important cost factor, as they need to accommodate for the daily needs of all the clients in the system as well as 2 day backup in this scenario.

As described in Chapter 4, the trucks and vans from the logistics company of the system will refuel at an Hydrogen Refuelling Station (HRS), that is built and operated by the refinery, in its grounds. The station has a capacity of 1,084 kg of hydrogen per day, assuming that 30% of the vehicles refuel during a 1 hour peak during the day. The capital costs of that station are presented below:

Upfront capital costs of the HRS (€)	
Cascade Compressor	1,074,084
Cascade storage	240,000

Dispensers	360,000
Installation costs	200,890
Non equipment costs	1,167,058
Pipeline	223,796
Storage	1,019,765
Total HRS CAPEX	**4,285,592**

In the case of the HRS the cascade compressor is the major cost component, because of the need to provide not only high pressures (350 bar) but high flowrates, to accommodate for the rush hour demand.

Operational costs:
The operational costs structure remains the same with the decentralised case for the hydrogen production part of the investment, in terms of hydrogen production. Also, the annual operating expense of the filling site and the HRs were calculated and presented below.

The annual operational costs breakdown of the filling site, are presented in the following table:

Table 5-30: Annual operational expenses of hydrogen production for the semi-centralised scenario

Annual expenses in €		
		PEM
Maintenance	Compressor	47,852
	Electrolyser	598,019
	Storage	3,840
Electricity	Storage Compressor	123,713
	Electrolyser	5,371,539
Labour		146,304
Total		**6,291,268**

Table 5-31: Annual Operational costs of H_2 filling skid

Annual expenses in €		
		PEM
Maintenance	Filling skid	47,852

	Storage	3,840
Electricity	Filling skid	28,474
Labour		120,523
Total		**231,311**

As shown in Figure 5-25 foth filling site the most important factor in OPEX is the cost of labour, even though the filling site only operates for 13 hours every day, or 1.6, 8-hour shifts.

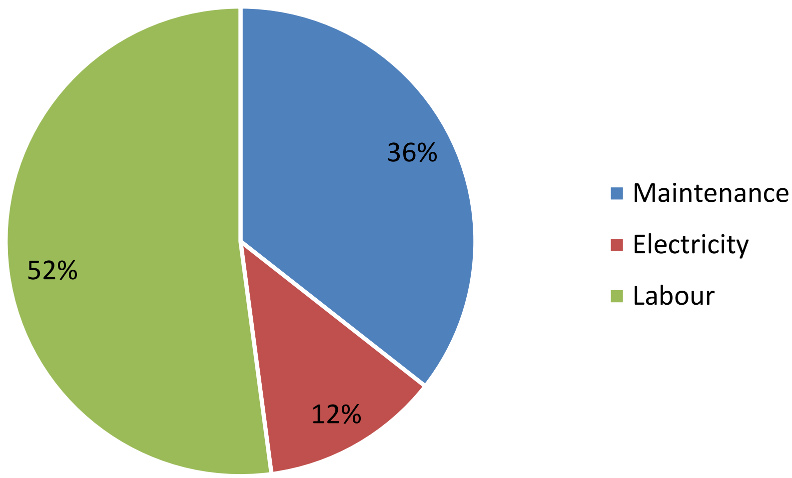


Figure 5-25: Operational cost breakdown of the filling site for the semi-centralised scenario

The HRS has as total of annual expenses of 121,000 €, almost equally distributed to electricity and maintenance costs of the storage and compressor.

Hydrogen cost breakdown

For the production cost of hydrogen the cost structure of the semi-centralised scenario, resembles the on-site scenarios. Figure 5-26, shows the contribution of each cost to the final cost of hydrogen per kg.

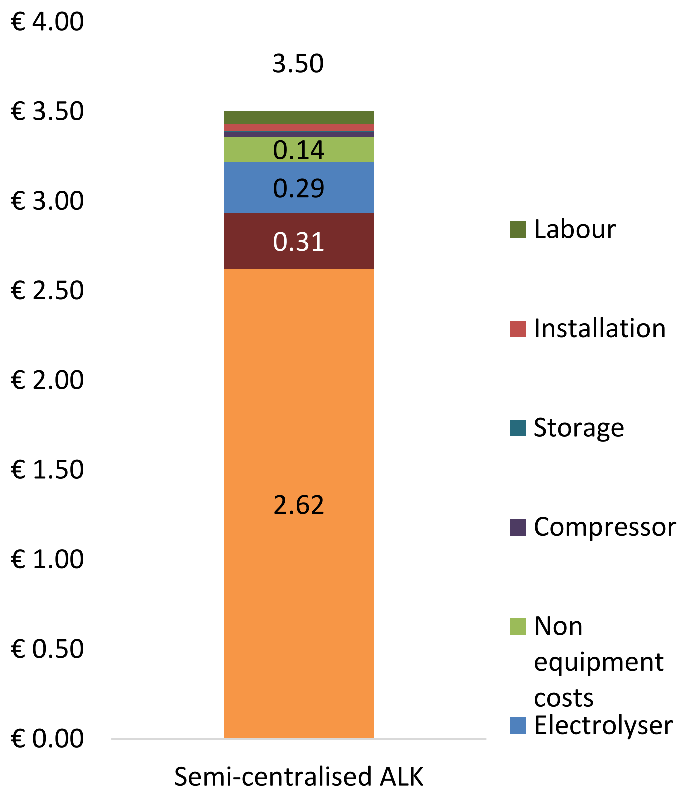


Figure 5-26: Hydrogen cost per kg breakdown for on-site scenarios for forklifts

As it was expected the cost is slightly lower than the corresponding alkaline electrolyser from the on-site scenario, due to the larger capacity of the electrolyser and the lower specific cost per MW.

The price of hydrogen for the glass and steel industries as well as the forklifts, that receive deliveries of from the refinery, is **7.41 €/kg**. The price of hydrogen at the pump of the HRS, for the vans and trucks, is **6.6 €/kg**; significantly lower, as it is not burdened with any delivery costs. These prices include

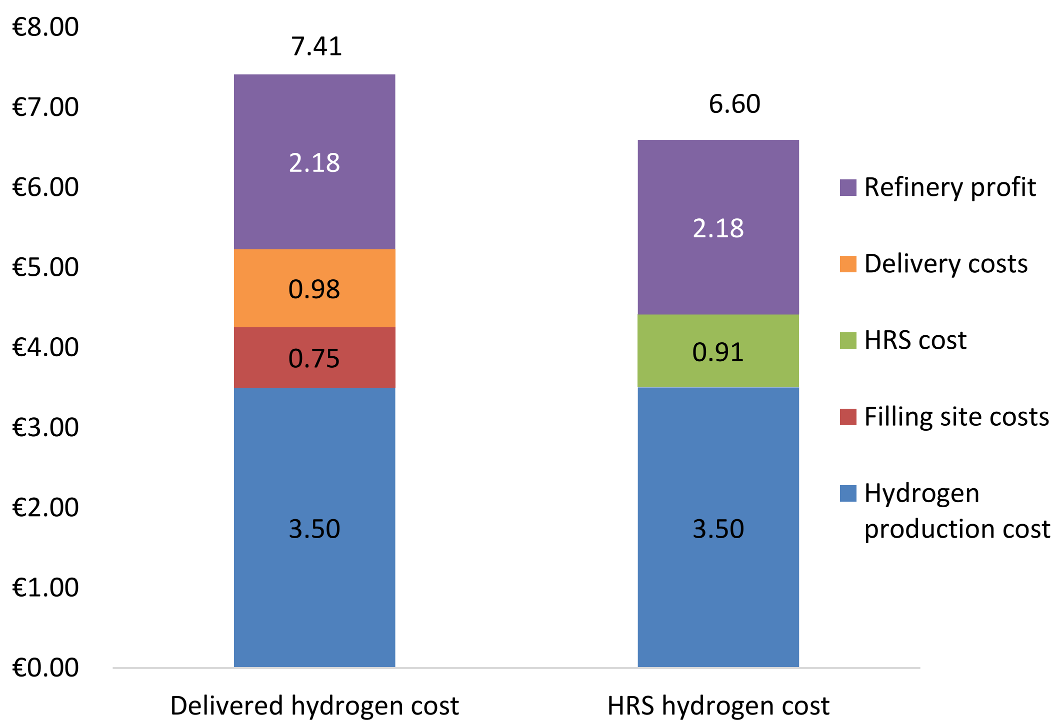


Figure 5-27: Hydrogen cost per kg breakdown for tube trailer delivery and at the pump of the HRS - semi-centralised scenario

Comparison with the base case and on-site scenario

As with the on-site production scenario, in the semi-centralised production the refinery are able to save on ETS allowances for carbon emissions. In addition, the earnings from the hydrogen delivery and sales from the HRS, provide additional income. All of the cash flows, including any additional future expenses like infrastructure replacements (eg. Electrolyser stacks) and revenues, are discounted to the present day, and the results are presented in Table 5-32:

Table 5-32: Net Present Values comparison for the refinery for every hydrogen production system

Net present values of all costs in millions €				
	Base Case	On-site		Semi-central (including revenues from sales)
	SMR	PEM	ALK	ALK
NPV	44.9	77.3	59.5	38.9
Difference from base case	-	72.3 %	32.5%	-13.3 %

Table 5-32 shows that due to the sales of hydrogen in the semi-centralised scenario, the investment in P2H not only comes does not come at a cost to the refinery, in fact it produces a small income, and it is the best way for a refinery to adopt green hydrogen in its production and reduce its emissions.

5.4.2 Glass and steel industries

As shown in Chapter 4, there is no new investment in infrastructure for the glass and steel manufacturers. The upfront capital cost are exactly the same with base case scenario.

Comparison with the base case and on-site scenario

To compare with the other cases, the NPV values of the two cases are compared in Table 5-33 and Table 5-34:

Table 5-33: Net Present Values comparison for the glass plant for every hydrogen production system

Glass – net present values of cots in million €				
	Base Case	On-site		Semi-central
	Third party merchant	PEM	ALK	ALK
NPV	9.52	11.07	10.27	10.37
Difference from base case	-	20%	11%	12%

Table 5-34: Net Present Values comparison for the steel plant for every hydrogen production system

Steel				
	Base Case	On-site		Semi-central
	Third party merchant	PEM	ALK	Third party merchant (refinery)
NPV	41.4	32.08	28.55	36.32
Difference from base case	-	-23 %	-31 %	-12 %

For the glass industry, no green hydrogen scenarios prove to be profitable, however the in site scenarios show encouraging results, with the case of the ALK adding only 11 % to the total costs. The semi-centralised scenario, provides practically no additional costs to the ALK scenario.

The steel industry shows significant benefits from the installation of an electrolyser, especially from an alkaline one. Thanks to the increased daily demand of the plant, the electrolysers are scaled up enough to provide benefits, especially when the high hydrogen price of the base case scenario is considered as well.

For the glass and steel industries – and generally businesses that normally buy hydrogen with tube trailer delivery – the semi-centralised scenario, provides a risk free and worry free option; no infrastructure installing and operating is required. These businesses would simply change hydrogen suppliers.

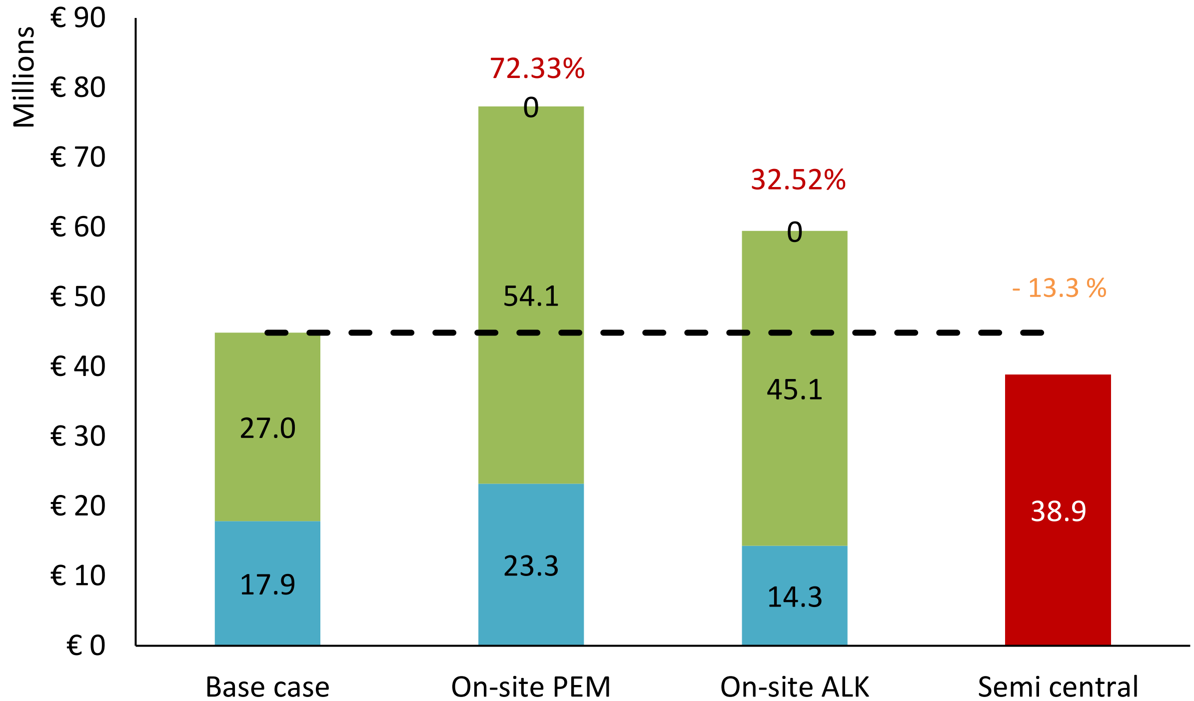


Figure 5-28: Net present value of all costs for all refinery scenarios (sales included in the semi-central scenario)

5.4.3 Forklifts

Capital costs:

Table 5-35_summarises the capital costs for the semi-centralised case for the forklifts and trucks/vans fleets. Note that in the case of vans and trucks there is no refuelling infrastructure on the site of the company; vehicles refuel at the refinery owned hydrogen station.

Table 5-35: Capital cost for the forklift fleet, semi-centralised scenario

		Forklifts
Electrolyser	Specific cost (per/kW)	-
	Total cost	-
Compressor (storage)		-
Cascade compressor		260,742
Storage (low pressure and cascade)		194,400
Dispenser		90,000
Non-equipment costs		218,056
Installation costs		65,417

Forklifts (Fuel cell stacks only) FC Vans/Trucks	1,400,00
Total CAPEX	**2,228,616**

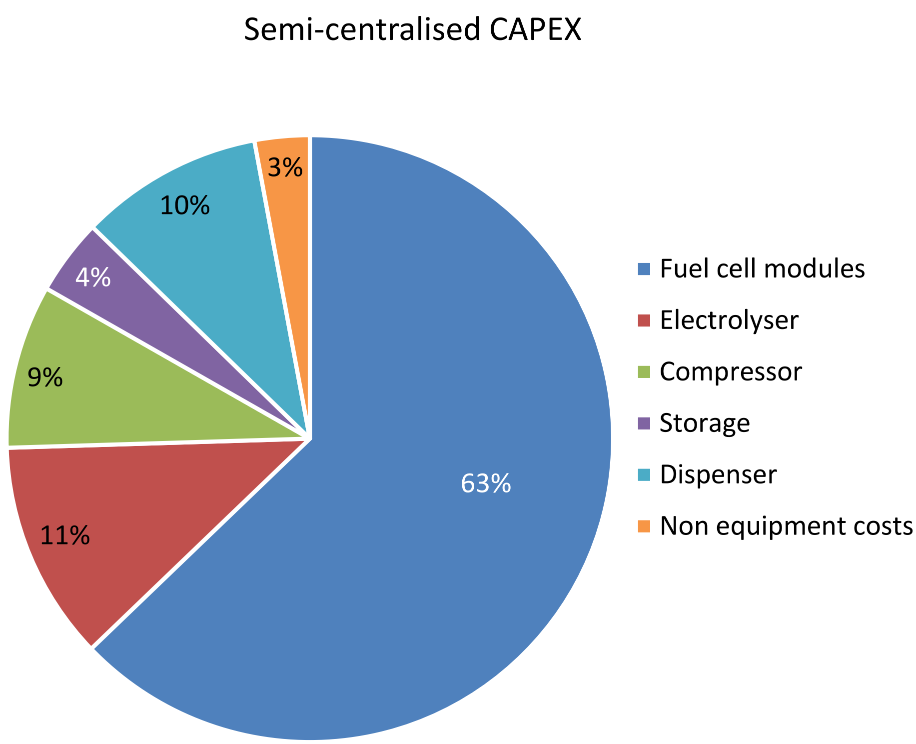


Figure 5-29: Cost breakdown of upfront capital costs of the forklifts for the semi-centralised scenario

In this case the fuel cells for the forklifts are the basic upfront component, as there is no electrolyser. As with the cases of the glass and steel industries, the upfront capital costs are significantly reduced. In the case of the forklifts, this reduction amounts to almost 50%.

Operational Costs

In this case there is no electricity costs ramping up the annual operational expenses, however, the forklifts operator must purchase hydrogen from the refinery. The overall annual expenses are about 40% higher than the ALK on-site scenario.

Table 5-36: Annual operational expenses of forklift fleet for the semi-centralised scenarios

Warehouse (Forklifts) - Annual operation expenses (€/year)		
Maintenance	Fuel cell stacks	100,00
	Cascade (both)	12,037
Electricity	Compressor	5,518
H2 from producer cost		480,360
Labour (3 min refuel)		76,200
Total		**675,115**

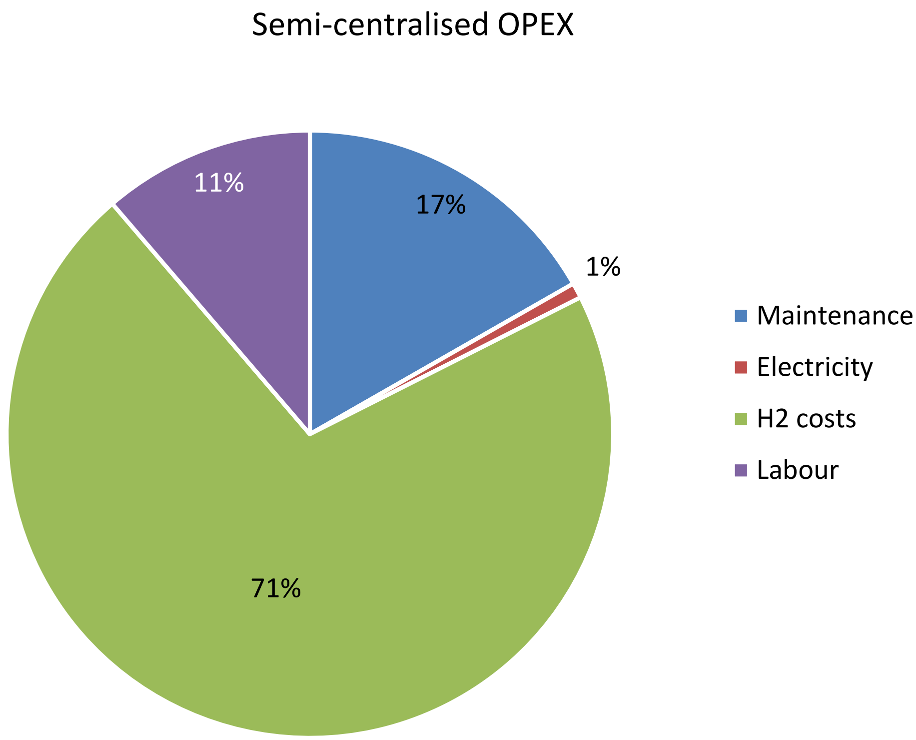


Figure 5-30: Operational costs of the forklifts breakdown for the on-site scenarios

Hydrogen cost breakdown

The cost of the hydrogen is driven almost exclusively from the price that the refinery can offer to the logistics company, as the storage and dispensing only equipment add only a small amount to the final cost.

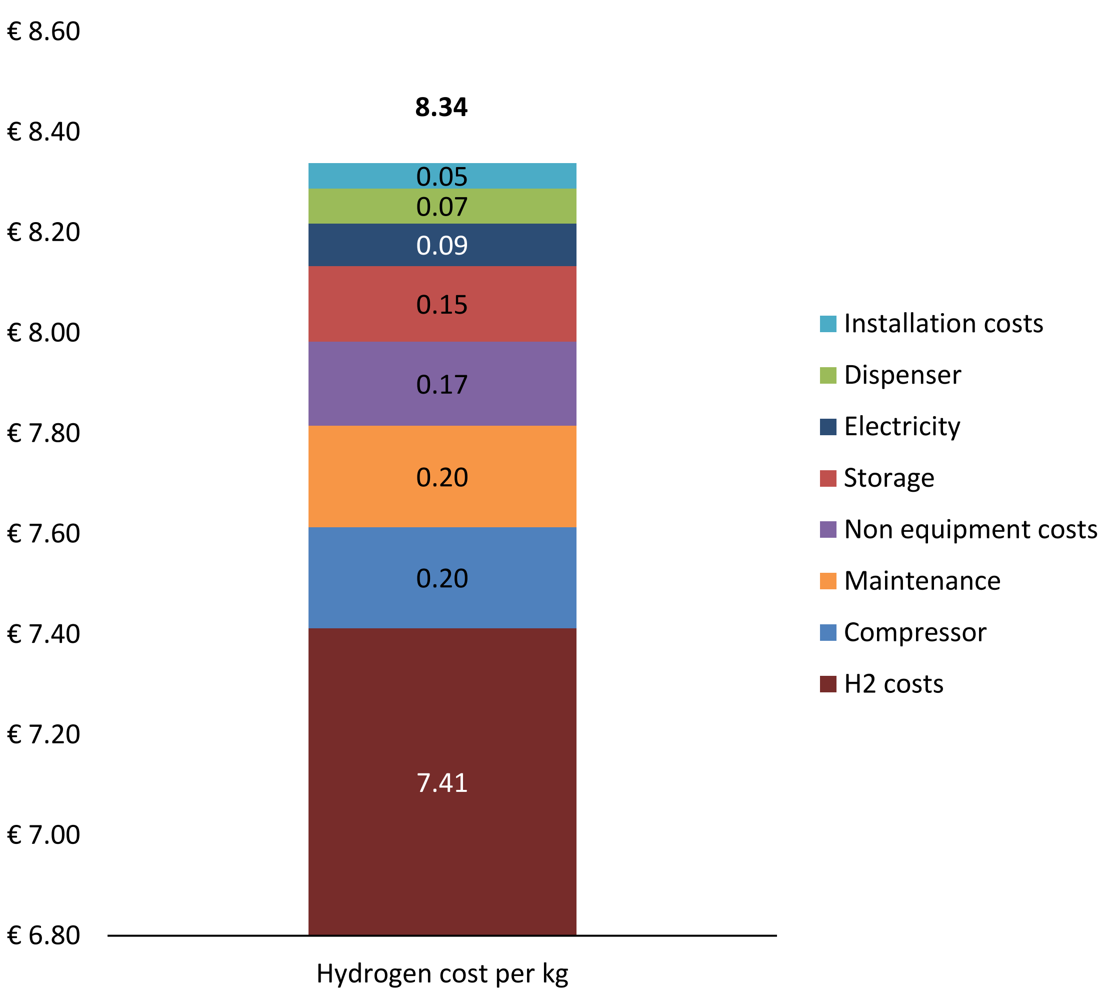


Figure 5-31: Hydrogen cost per kg breakdown for the semi-centralised scenario for forklifts

Comparison with base case and on-site scenario

The semi-centralised case results in lower costs than the base case, as with the on-site scenarios. Specifically, the semi-centralised scenario is only 1% more expensive that the ALK on-site case. As a result this hydrogen production configuration results in almost identically low costs as the ALK case, with the added benefit of reduced upfront CAPEX.

Table 5-37: Net Present Values comparison for the forklifts for every hydrogen production system

Net present value of costs in € (millions)				
	Base Case	On-site		Semi-central
	Third party merchant	PEM	ALK	Third party merchant (refinery)
NPV	13.0	12.7	11.4	11.6
Difference from base case	-	-2%	-12%	-11%

5.4.4 Vans and trucks

Capital costs

The transportation company's capital cost for the semi-centralised scenario, resembles the base case; the operator only purchases vehicles and no further equipment. The costs for purchasing the FCEVs *Table 5-38*.

Table 5-38: Capital costs of the semi-centralised scenario for vans and trucks

	Upfront capital costs – vans and trucks (€)
	Semi-central
Installed Capacity (MW)	0.90
Vans	5,100,000
Trucks	12,000,000
Total	**17,100,000**

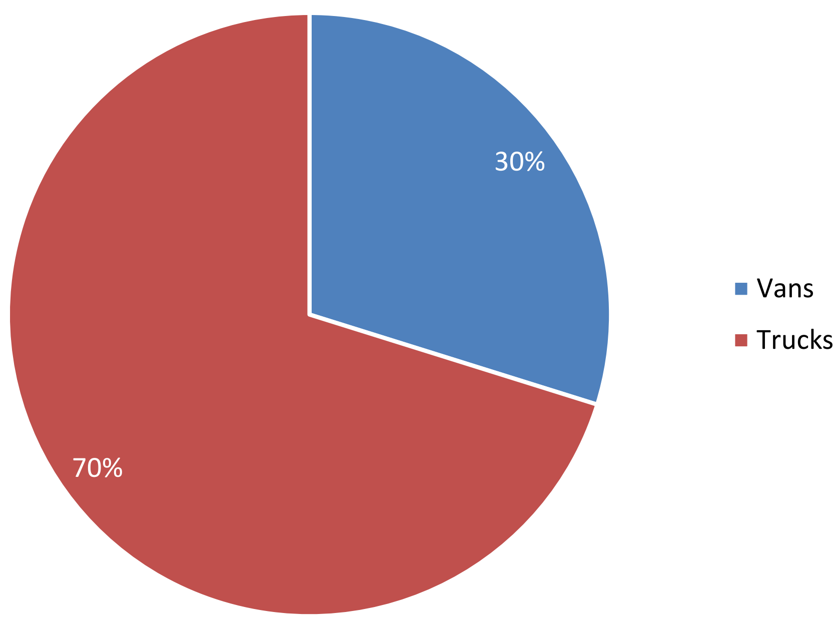


Figure 5-32: Upfront capital costs breakdown for the vans and trucks fleet – semi-centralised scenario

As expected the cost allocation is identical to the base case, only this time the costs are 3x higher, due to the greater cost of FCEVs.

Operational Costs

The operational costs are identical to the other P2H scenarios in terms of the vehicles. Only difference is the lack of hydrogen infrastructure operation and maintenance.

Table 5-39: Annual operational costs of the vans and trucks for the semi-centralised and base case

Annual operational costs (€)			
		Semi-central	Base case
Maintenance	Vans	34,000	102,000
	Trucks	127,500	382,500
H2 costs	Vans	187,237	204,000
	Trucks	2,242,354	1,836,000
Total		**2,591,090**	**2,524,500**

The overall annual costs for FCVEs are almost identical to the costs of diesel vehicles. The fuel cell vehicles are have significantly reduced maintenance costs and their refuelling at 6.6 €/kg of hydrogen is, in total, lower.

Infrastructure replacement costs

The vehicles are replace as in on-site scenarios; every 10 years, or once in the lifetime of the project. The cost of the vehicles, was assumed, to have dropped by that time.

Table 5-40: Replacement costs for the diesel trucks and vans case

Replacement costs (€)		
	PEM	ALK
Vehicles	8,550,000	

Hydrogen cost breakdown

The hydrogen costs presented in Figure 5-33 show that by refuelling in the HRS at the refinery, the company operating the vehicle fleet can purchase hydrogen at a slightly higher price, compared to the ALK on-site scenario.

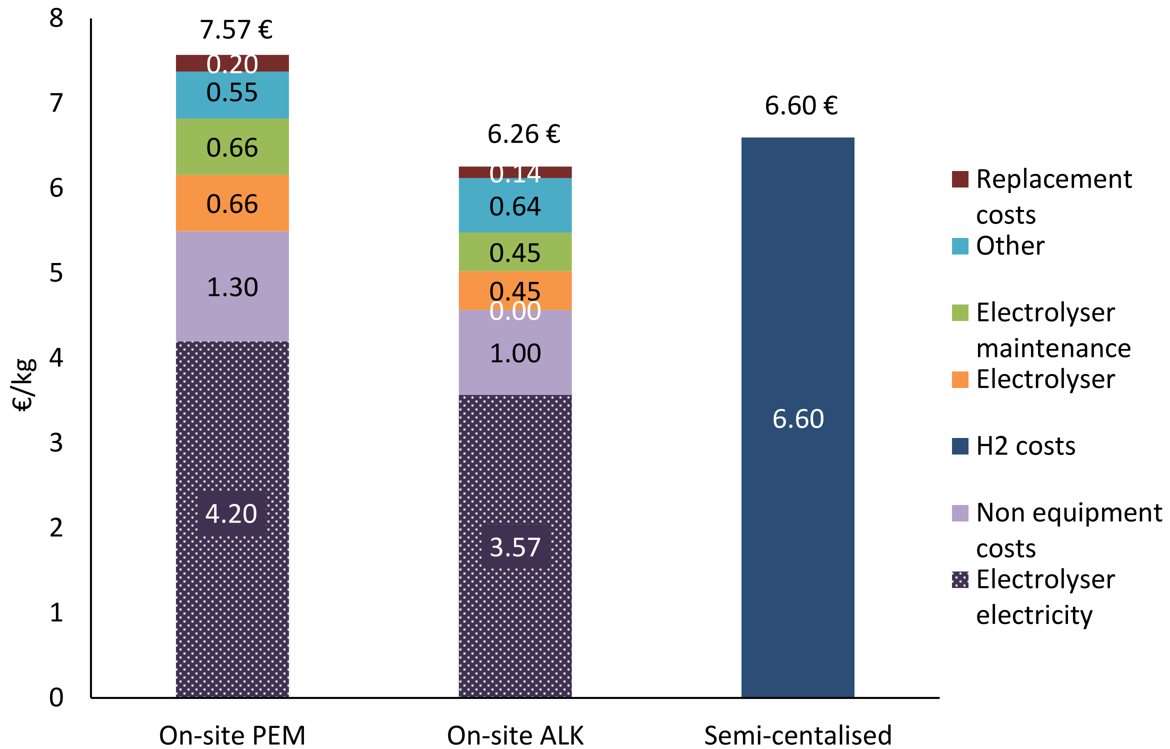


Figure 5-33: Hydrogen cost per kg breakdown for on-site scenarios for vans and trucks

Comparison with base case and on-site scenario

The semi-centralised case results in higher costs over 20 years than the base case. However, at 15%, the additional expenses are not completely prohibiting, for converting a whole fleet to zero-emissions. It is also reminded that the costs of purchasing the FCEVs at Year 1 is completely funded by the buyer and no government incentives are included.

Table 5-41: Net Present Values comparison for the steel plant for every hydrogen production system

Net present value of costs in € (millions)				
	Base Case	On-site		Semi-central
	Third party merchant	PEM	ALK	Third party merchant (refinery)
NPV	42.6	61.7	55.7	49.0
Difference from base case	-	45%	31%	15%

6 Sensitivity analysis

6.1 Introduction

In this chapter, the author investigates the effect of various economic considerations on the present value of costs. First, the effect of the discount rate is investigated. Hydrogen and fuel cell technologies are relatively new, which means that the discount rate, namely the investment risk, is subject to uncertainty.

Then, looking into each separate industry, the author identifies the biggest cost contributors and investigates the effect of a variation of these contributors to the final present value of costs.

6.2 General Parameters

6.2.1 Discount rate

The discount rate greatly affects the NPV of any investment as it determines the time value of money. For a discount rate of zero, the cash flows over the investment horizon will be worth the same in the NPV calculations; €1 earned in year 10 would be the same as €1 earned in year 2. On the other hand, as the discount rate increases, revenues (or expenses) in the future are valued less than cash flows taking place today. Due to this effect, higher discount rates, will decrease the impact of OPEX in NPV calculations and therefore, favour OPEX intense business cases. Taking into account that all of the scenarios in this analysis were made for a rather large timeframe of 20 years, it was imperative to explore the impact of the discount rate. It is also important to notice that the discount rate for the exact same investment might differ between different companies as it lies upon the analyst to choose the rate that best reflects the reality of the project.

Table 6-1: Discount rate sensitivity analysis

Parameter		Range		
	Default	Minimum	Maximum	Reason
Discount rate	8%	5%	10%	Greatly affects the evaluation of an investment by changing the importance of future cash flows in the PV calculation

<u>Refinery</u>

For the on-site production cases (both PEM and ALK), an increase in the discount rate returns a significant reduction in the Present Value (PV) of costs and its difference from the base case. This is due to the high OPEX of the investment, that is discounted more when the rates are higher, resulting in lower PV cost. The semi-centralised scenario behaves differently; the PV of the costs increases and finally overcomes the base case scenario as the discount rate gets higher. This is caused by the decreased PV of future cash inflows from the sales of hydrogen. As these values become less important with a discount rate increase, they are not enough to balance the increased upfront costs.

Figure 6-1 shows the NPVs of the costs for the refinery, including the sales in the case of the semi-centralised scenario, as the discount rate varies from 5% to 10%.

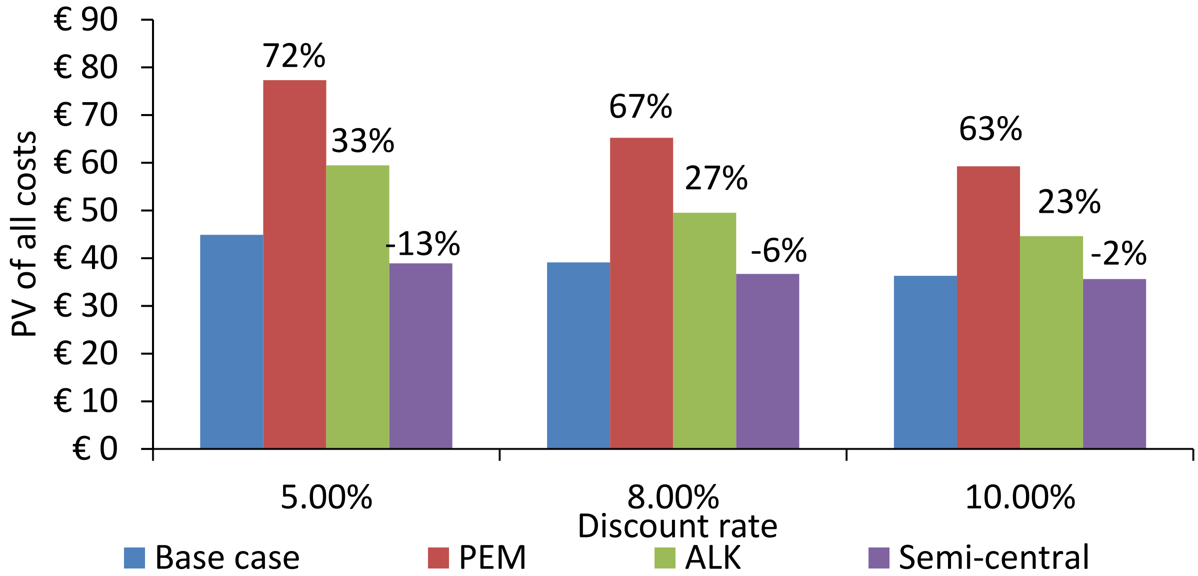


Figure 6-1: Net Present Values of all costs (including sales for semi-central) compared to the base case scenario - discount rate sensitivity for the refinery case

Below in Table 6-2, the internal rate or return (IRR) is shown for the different scenarios.

Table 6-2: Discount rates necessary to breakeven with the base case – refinery

Scenario	IRR
On-site PEM	-∞
On-site ALK	30.38%
Semi-centralised	10. 69%

The PV of costs of the on-site PEM scenario cannot, under any discount rate consideration, match the base case scenario, while for the on-site ALK scenario hydrogen production would require a discount rate of 30.38% or greater to match the costs of the SMR production. That of course is a non-realistic discount rate, since in most analyses, even high rates do not exceed 15%. The semi-centralised case however is a sensible option for discount rates up to 10.69%.

Glass and metallurgy industries

The behaviour of the glass and metallurgy industries to the discount rate changes, is opposite to the refinery, as the expenses are allocated differently. Contrary to the refinery, the on-site production scenarios, have a higher than the base case CAPEX investment, that significantly reduces the OPEX for the next 20 years. As a result, an increase to the discount rate, diminishes this advantage by devaluing the future cost reductions. This behaviour is shown in Figure 6-2 and Figure 6-3 below. The charts also show a constant difference between base case and semi-centralised scenarios regardless of the discount rate. This happens in these industries specifically, due to the similarity between the cost structures; both the base case and semi-central models have identical CAPEX and the OPEX consists only of steady cash outflows from the purchasing of the delivered hydrogen. Therefore, the discount rate affects both cases in the same way, and the gap between them remains constant.

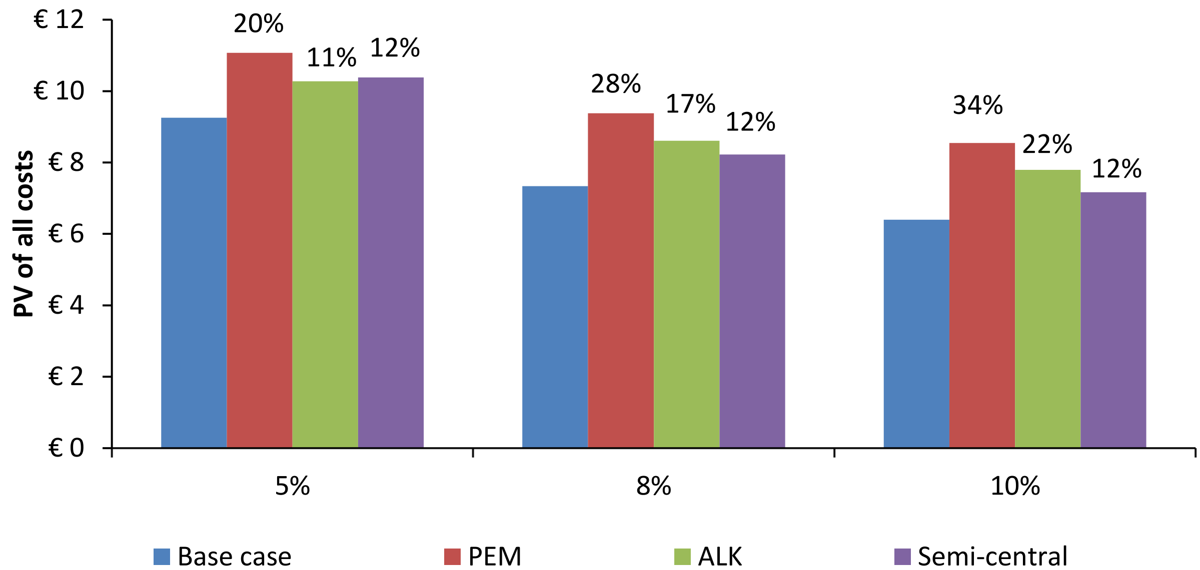


Figure 6-2: Glass industry - PV of total costs and difference from the base case for different discount rates

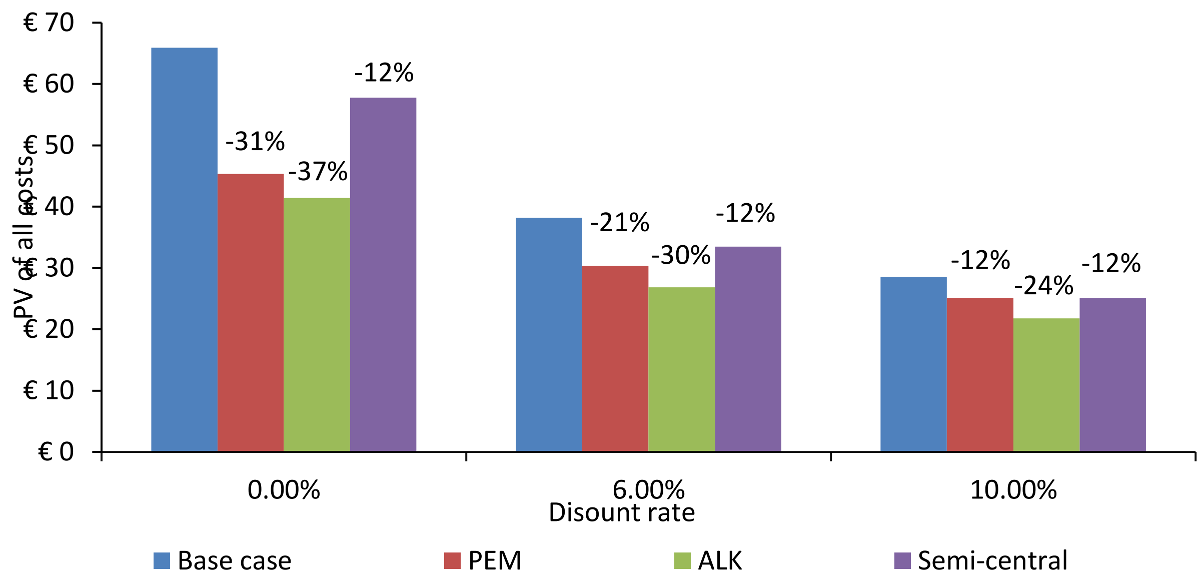


Figure 6-3: Metallurgy industry - PV of total costs and difference from the base case for the different discount rates

As Table 6-3 shows, P2H scenarios cannot match the costs of the base case scenario for any discount rate for the case of the glass industry. For the steel industry, for discount rates below 15.22% and 24.3% the PEM and ALK are, repectively attractive investment options, while the semi-centralised scenario difference from the base case is not affected by the discount rate. These results are also presented in Figure 6-4 and Figure 6-5.

Table 6-3: Discount rates necessary to breakeven with the base case – glass and metallurgy

Scenario	Default discount rate used	IRR	
		Glass	Steel
On-site PEM	5.00%	-	15.22%
On-site ALK		-	24.3%
Semi-centralised		∞	∞

As shown below, in Figure 6-2 and Figure 6-3, in the case of the glass industry, for projects using a discount rate above 5%, the semi-centralised model is a more attractive option for green H_2 adoption, although it can never compete with the base case. For the steel plant, on-site P2H is an attractive option even for a discount rate as high as 10%. The cost advantages, however, quickly diminish as the rate increases. This of course happens due to the smaller value of the future cash savings when high discount rates are used.

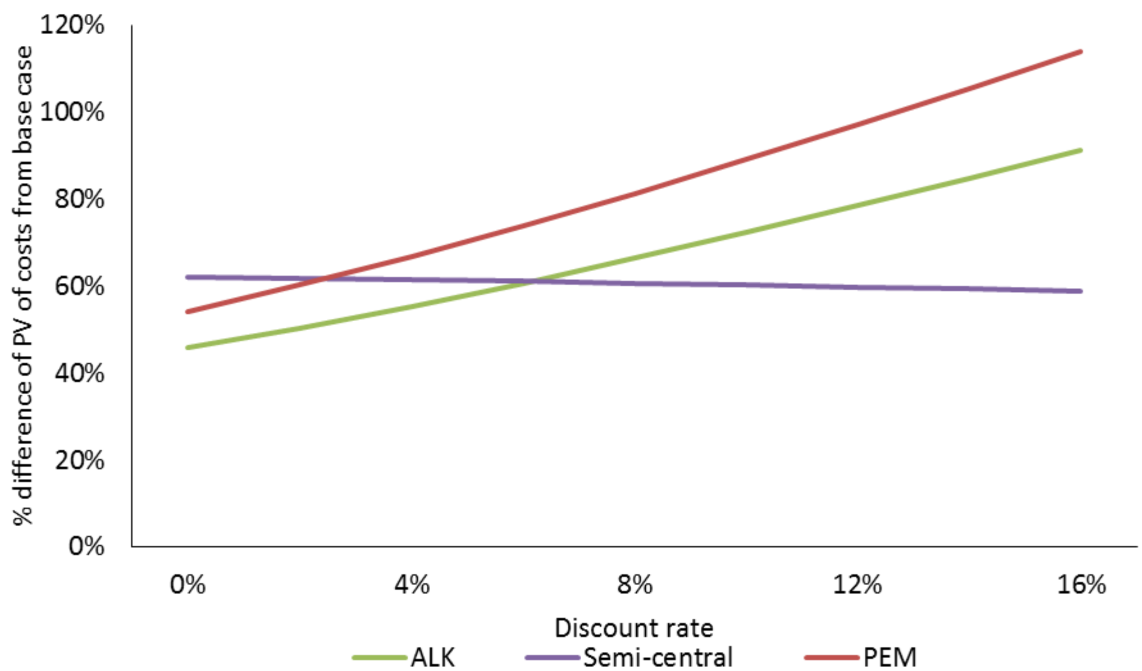


Figure 6-4: Difference of PV of costs of P2H scenarios from base case vs the discount rate for glass industry

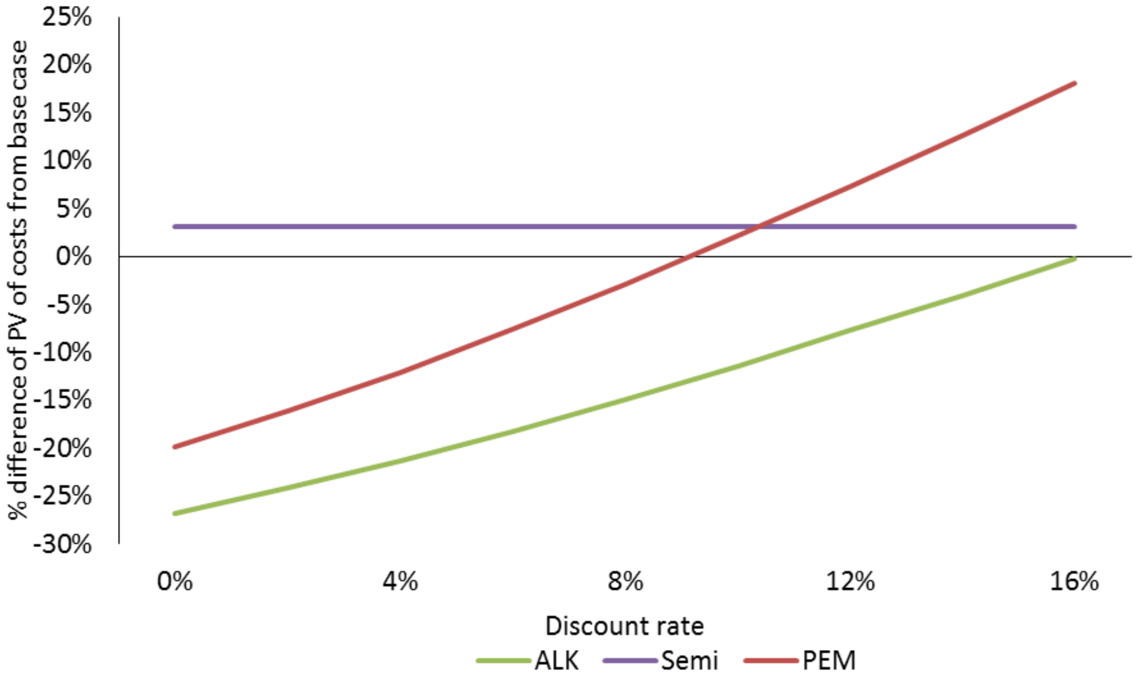


Figure 6-5: Difference of PV of costs of P2H scenarios from base case against the discount rate for metallurgy industry

<u>Forklifts</u>

Forklifts display similar behaviour to the glass/metallurgy industries; the semi-centralised scenario's difference from the base case remains almost steady, while the on-site scenarios become less favourable with increased discount rates. The results are shown in Figure 6-6.

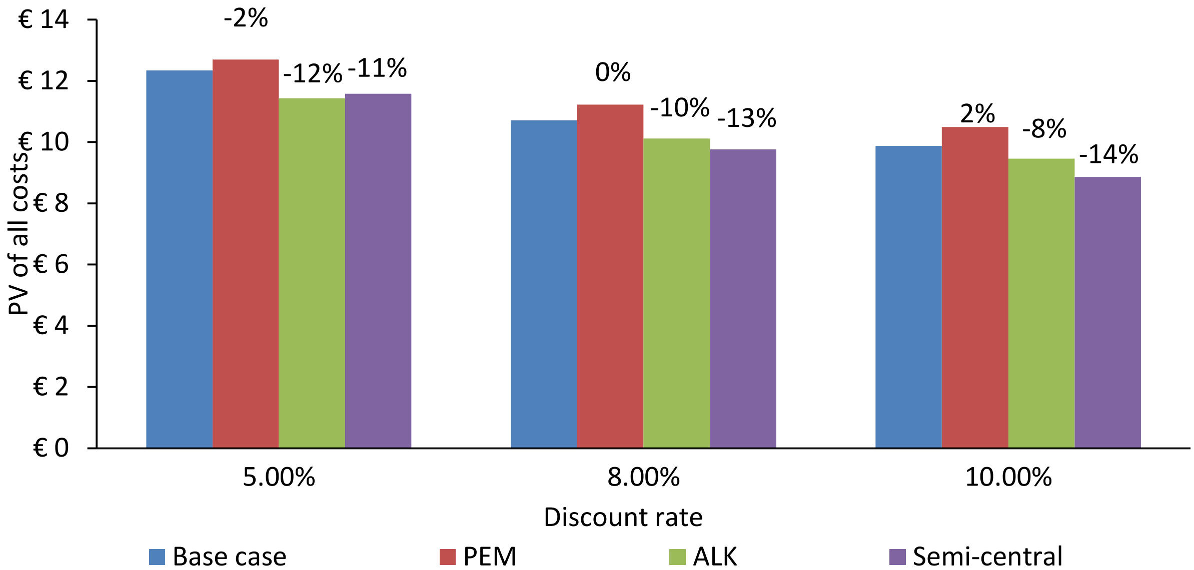


Figure 6-6: Forklifts - PV of total costs and difference from the base case for the different discount rates

On-site hydrogen production using an alkaline electrolyser is the most economically viable option for the assumed warehouse for discount rates below 5.75 %; beyond that, the semi-centralised case is the most profitable.

Table 6-4: Discount rates necessary to breakeven with the base case – forklifts

Scenario	Default discount rate used	IRR
On-site PEM	5.00%	7.78 %
On-site ALK		18.58 %
Semi-centralised		-

As Figure 6-7 shows, the semi centralised scenario has a very small discount rate elasticity; the same case cannot be made for the on-site production scenarios, where a 5% increase of the discount rate can increase by an additional 8% and 9% the PEM and ALK cases – compared to 0.09% for the semi-centralised scenario.

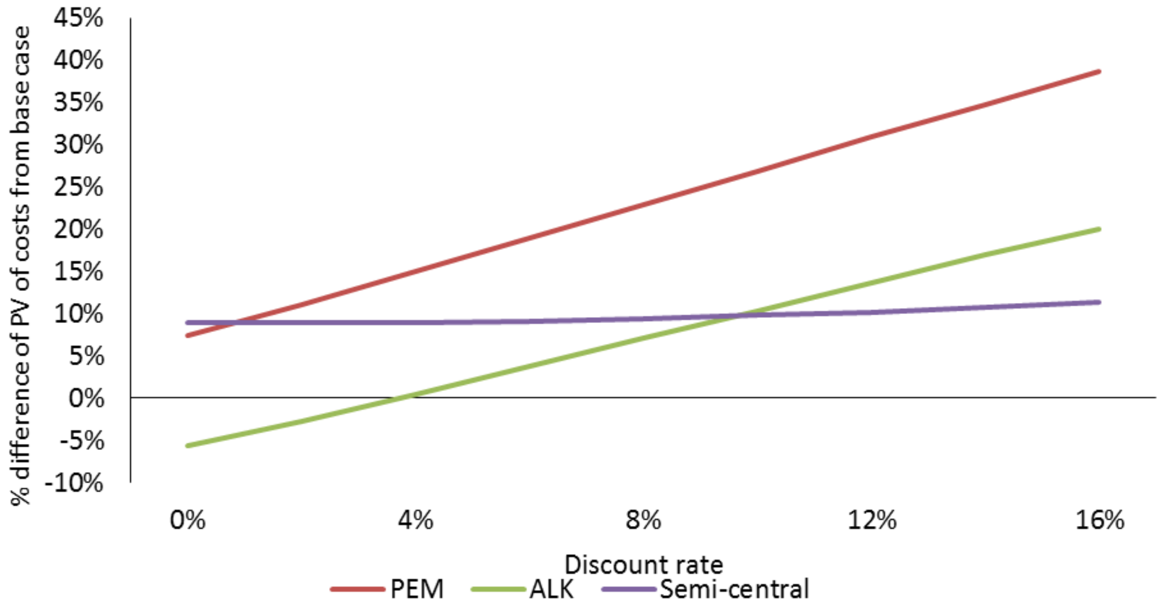


Figure 6-7: Difference of NPVs of P2H scenarios from base case against the discount rate for the forklifts fleet

Vans/Trucks

For the transportation company P2H costs do not match the base case scenario regardless of the assumed discount rate. As with the case of forklifts, an increase of the discount rate follows an increase of the difference between on-site P2H scenarios and base case. Unlike the before however, the cost difference between semi-centralised scenario and base case does not remain constant; it also increases.

The base case scenario for the vans/trucks is OPEX intensive; most of the costs are due to annual expenses for fuel and maintenance. For on-site production scenarios, CAPEX is the main contributor to the overall costs throughout the lifespan of the investment. As before, increasing the discount rate favours the OPEX intense investments (as their impact on PV evaluation is less important) and as a result the base case scenario becomes more attractive with higher rates. This behaviour is presented in Figure 6-8.

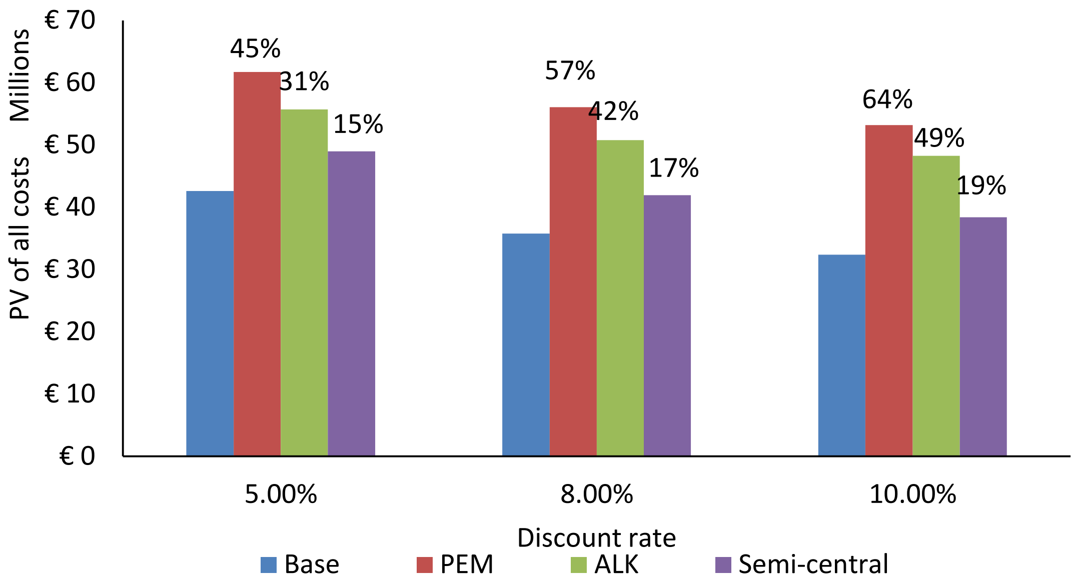


Figure 6-8: Vans/trucks - PV of total costs and difference from the base case for different discount rates

Although the semi-centralised model also becomes more costly as the discount rate increases, it displays a higher resilience with only a 9% cost increase from the base case at the extreme 10% discount rate; on-site scenarios shoot up by 19% and 18%. This is represented by the slope of the semi-central scenario cost curve in Figure 6-9 below.

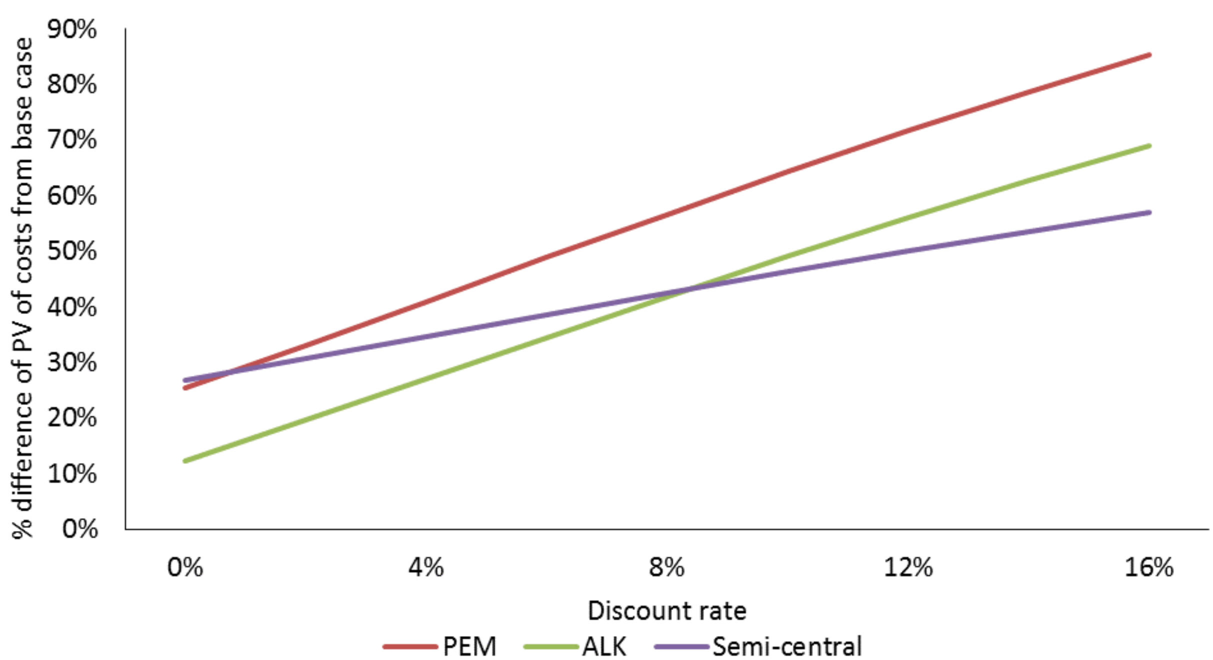


Figure 6-9: Difference of NPVs of P2H scenarios from base case against the discount rate for the vans/trucks fleet

The on-site ALK scenario exceeds the costs of the semi-central scenario for discount rates over 8 % but never breakeven with the base case.

6.3 Sensitivity on specific factors

6.3.1 Refinery

In the case of the refinery the most important cost parameters along with their sensitivity analysis limits are described in

Table 6-5.

Table 6-5: Sensitivity analyses performed for the refinery

Expense type	Parameter	Default	Range		Reason
			Min	Max	
CAPEX	Non equipment costs	(As % of uninstalled CAPEX) 20% for SMR 40% for P2H	20%	60%	Uncertainty of value – Highly variable between sites
OPEX	Maintenance of electrolyser	5% of electrolyser uninstalled CAPEX	3%	7%	Affected by the scale of the site, greatly affecting OPEX
	Daily demand of hydrogen	3,200 kg/day	1,200	6,200	Could lead to increased revenues.
	ETS cost	5.56 €/tonne CO_2 emitted (SMR only)	5.56 €/tonne	30 €/tonne	Future increase due to regulation change – Severe increase of SMR H_2 costs
	Electricity costs (base costs)	0.0500 €/kWh	0.0300 €/kWh	0.0700 €/kWh	Greatest cost parameter of P2H scenarios, possible cost reductions from SPOT market participation

<u>Non equipment cost</u>

Because of a significant amount of uncertainty around the % of the CAPEX that should be used for the P2H scenarios, a sensitivity analysis was carried out. The costs varied from 20% to 60%.

As shown below in, Figure 6-10, the semi-centralised scenario is the most affected by such a variation. The non-equipment costs for the base case were assumed to be 20% of the SMR CAPEX and are not varied in this analysis. This large variation is due to the fact that these costs affect both the production part, as well as the filling site and the Hydrogen Refuelling Station (HRS) of the semi-centralised scenario. Therefore the difference between base case and P2H scenarios, increases, with different rates for on-site and semi-central scenarios.

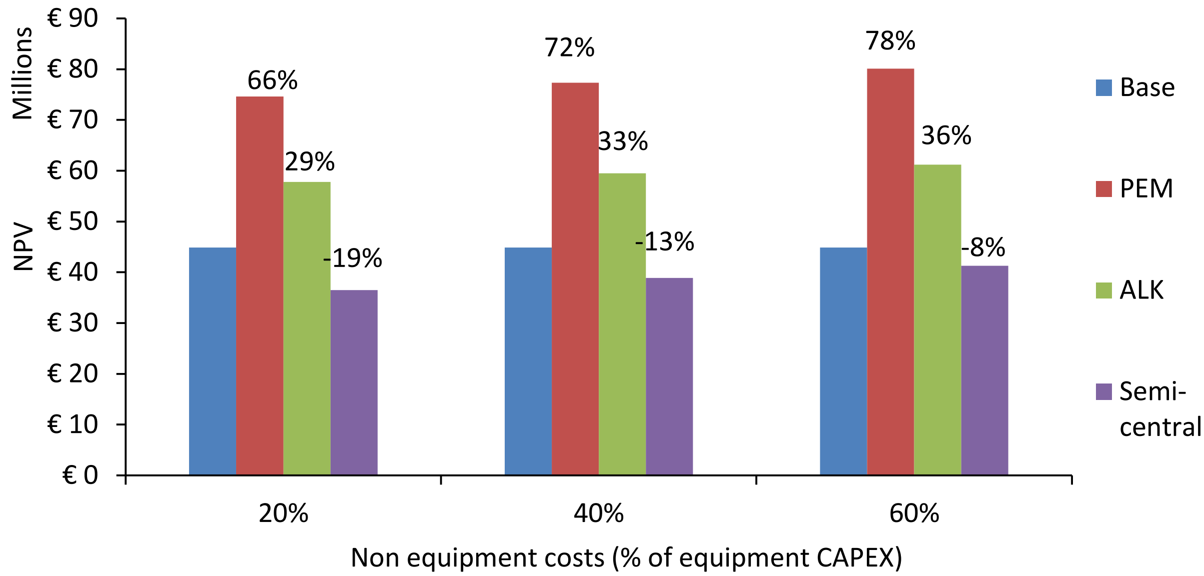


Figure 6-10: PV of costs versus cost of non-equipment costs for the refinery

<u>Electrolyser maintenance</u>

The 5% of the electrolyser's CAPEX that was assumed as the annual expenses of the electrolyser maintenance, are a significant cash outflow and especially for the refinery this percentage might be different than what the literature suggests, due the very large scale.

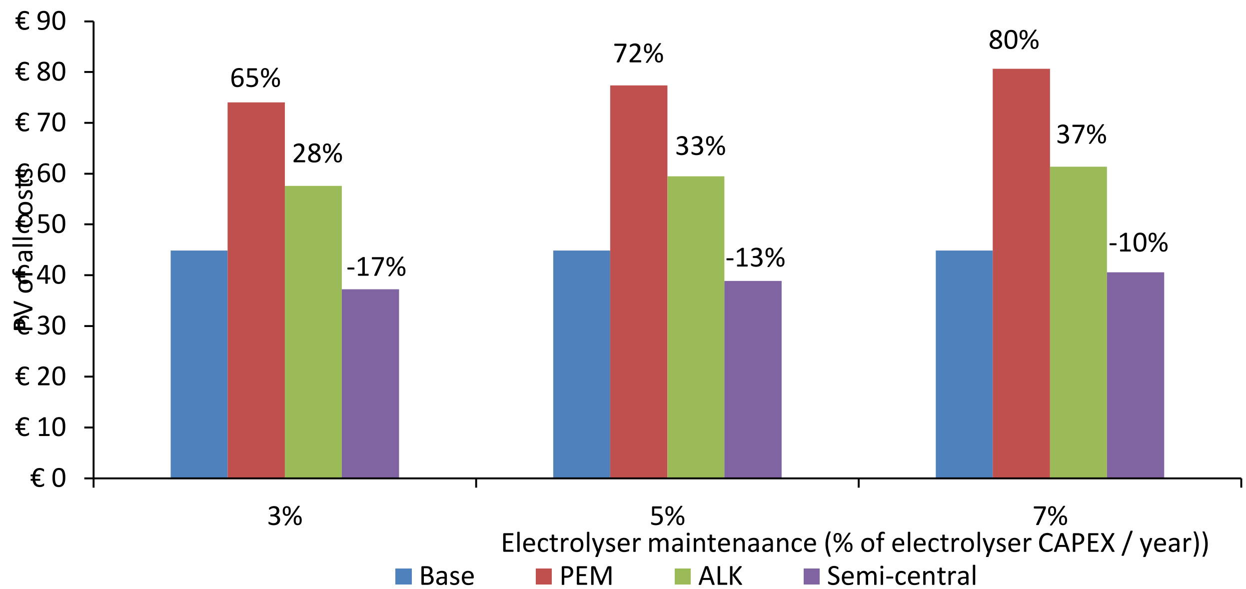


Figure 6-11: NPV of all the scenarios for various annual electrolyser maintenance costs (as % of electrolyser CAPEX)

As Figure 6-11 shows, a change in the annual costs of maintenance affects the profitability of the semi-centralised case over the base case scenario. A 2% decrease in the annual maintenance of the electrolyser results in 4% lower overall costs over the lifetime of the investment.

Electrolyser stack replacement costs

Due to the fact that electrolyser technology is relatively new, the cost of the replacement of the stacks might differ from what was assumed, depending on the progress of the cost reductions that are expected.

The replacement of the stacks that typically occurs after 10 years shows little to no difference in the overall costs of the P2H scenarios. Since it is a one-time future expense, it does not impact greatly the overall performance of the investment. Especially for the case of the semi-centralised system, the difference is negligible, due to the small share of the stack replacement costs to the overall costs.

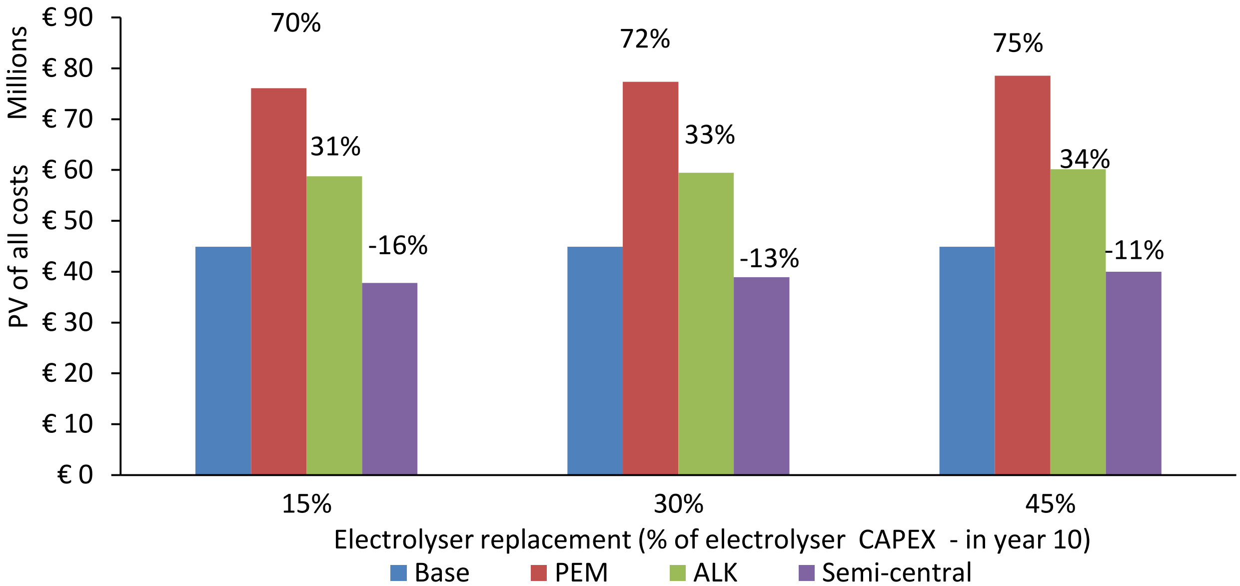


Figure 6-12: PV of all the scenarios for various non-equipment costs for the refinery

Electricity costs

The electricity costs are the most important factor in the production of hydrogen through electrolysis. It is possible that the electricity costs can be reduced even further from participation in the intra-day electricity markets as shown in [70]. It should be noted that this electricity price sensitivity refers to the base price of the electricity, excluding the costs of the guarantees of origin, because of their very small contribution to the overall electricity costs.

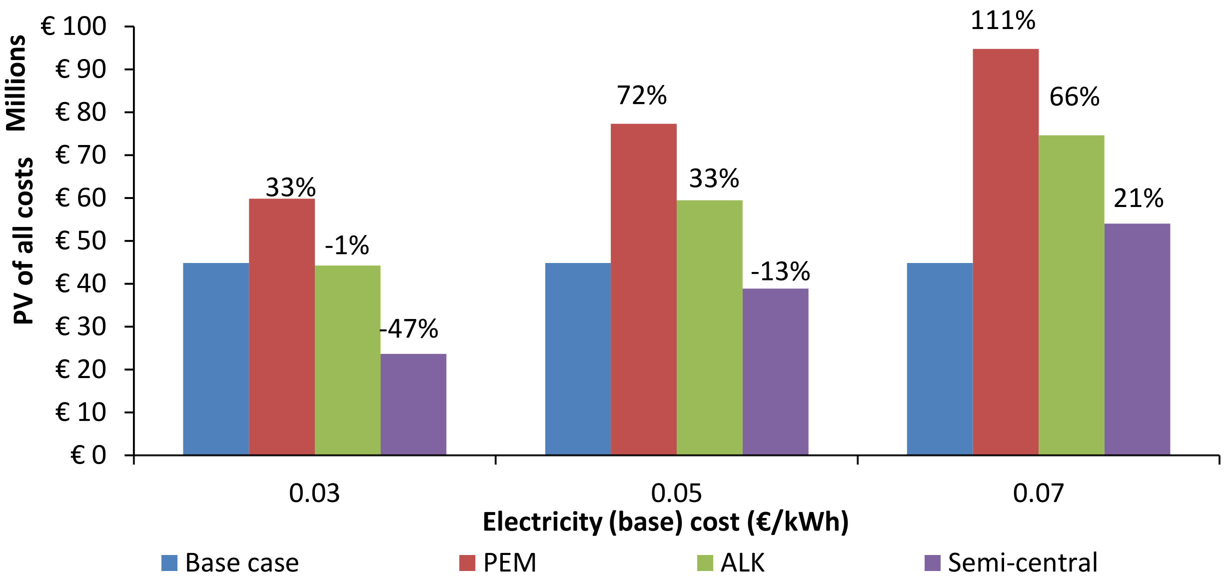


Figure 6-13: PV of all the scenarios for various electricity (base) prices for the refinery

Figure 6-13 shows that changes in electricity price, can drive the NPV of the costs for the different P2H scenarios to the extremes.

A decrease of the electricity price to 0.03 €/kWh decreases the costs by 39%, 34% and 30% for the PEM, ALK and semi centralised scenarios.

Table 6-6: Cost of electricity for P2H scenarios to breakeven

	Breakeven costs of electricity
PEM	12.8 €/MWh
ALK	30.8 €/MWh
Semi-central	57.9 €/MWh

ETS

The price of a tonne of CO_2 emitted from the production of hydrogen using SMR, increases the annual OPEX and therefore affects the NPV of the costs for the base case. The gap between the costs of the P2H scenarios and the SMR case, steadily decreases for the ALK and PEM cases and increases for the semi-centralised scenario. Therefore, an increased emissions price in the ETS, can make the ALK on-site case profitable, but only for prices of €100/tonne$_{CO2}$ and above.

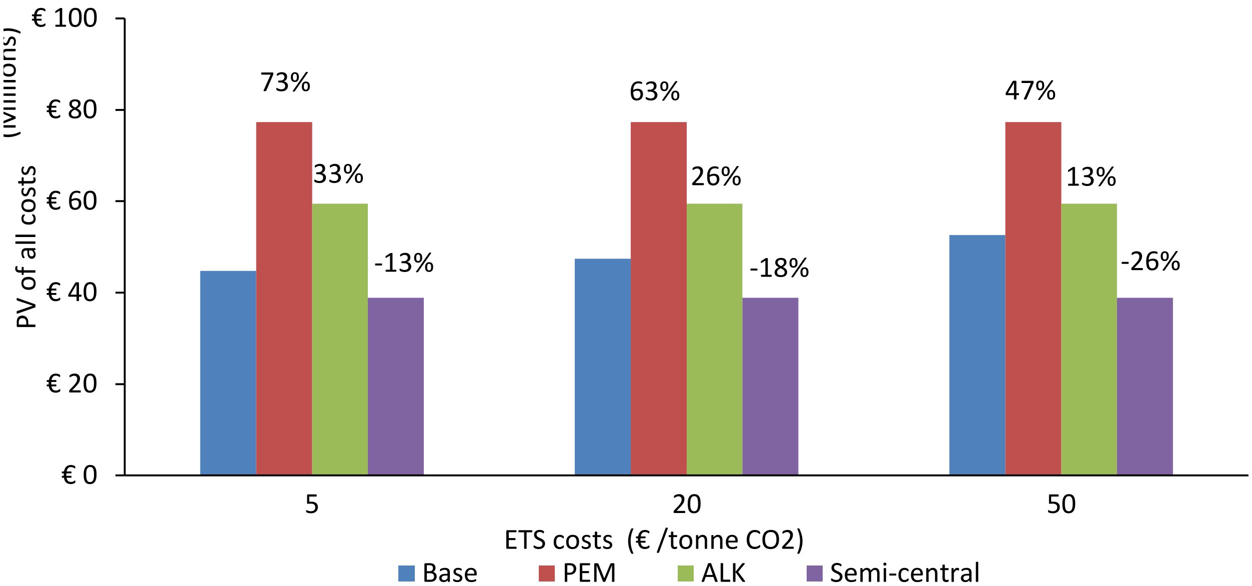


Figure 6-14: PV of all costs for all scenarios for various costs of CO_2 emissions (€/tonne$_{CO2}$)

<u>Daily demand of the refinery</u>

For the default scenario 3,200 kg of hydrogen were assumed to be replaced by the P2H installation, reflecting a 10% replacement of the daily demand by electrolytic hydrogen. As shown in Figure 6-15, an increase of the daily demand, and subsequently the electrolyser's size, results in a closing of the gap for the on-site scenarios. As shown, both ALK and PEM scenarios, improve by about 3% for every additional tonne of daily production. This improvement, caused by the scaling up of the electrolyser, fades as daily production increases, in accordance to Figure 4-17.

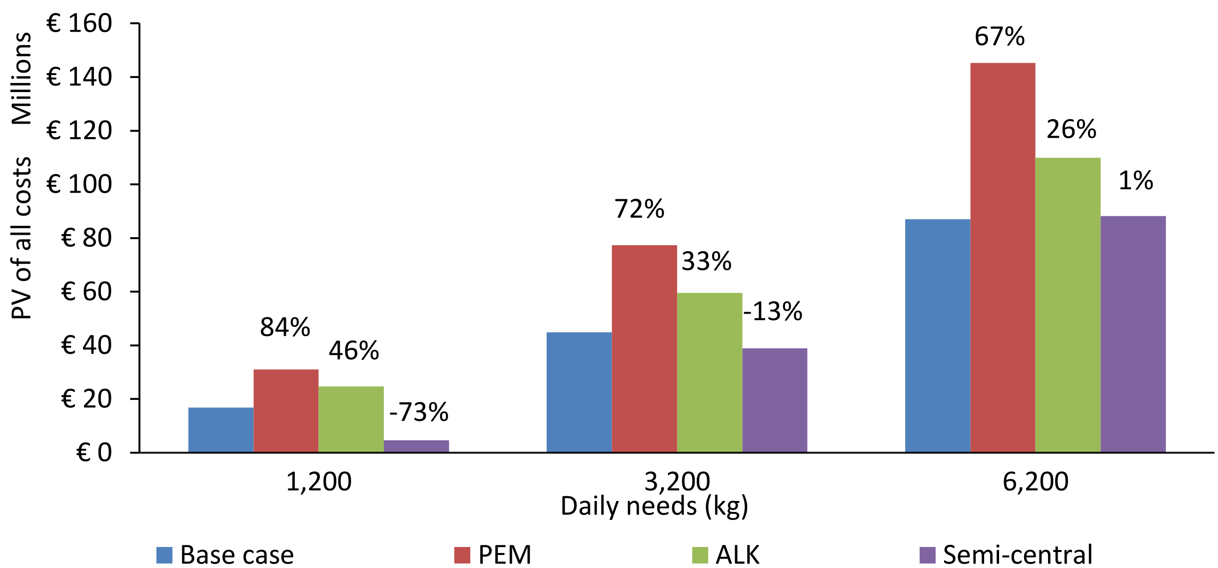


Figure 6-15: PV of all costs for all scenarios for various daily demands of the refinery (other companies' demand unchanged)

The opposite behaviour is exhibited by the semi-centralised model. The main driver of profitability for the semi centralised scenario, is the sales of hydrogen to other companies which ensures adequate income to overhaul the high cost of production of electrolytic hydrogen. As these sales represent a smaller share of the overall cash flows for larger daily refinery needs, the semi-centralised scenario approaches the on-site ALK scenario. On the other hand, for smaller refinery demands, the semi-centralised scenario, approaches a gas vendor business model. In this case most of the hydrogen is sold to the other companies, and the additional cost of green hydrogen production of the refinery is almost entirely covered from the sales of hydrogen.

To identify how much hydrogen needs to be sold to make the investment to the semi-centralised production system worthwhile, the ratio of kg_{H2} sold to other business to kg_{H2} consumed from the refinery was plotted against the difference of the NPV of the semi-centralised case from the base case. The results are presented in Figure 6-16.

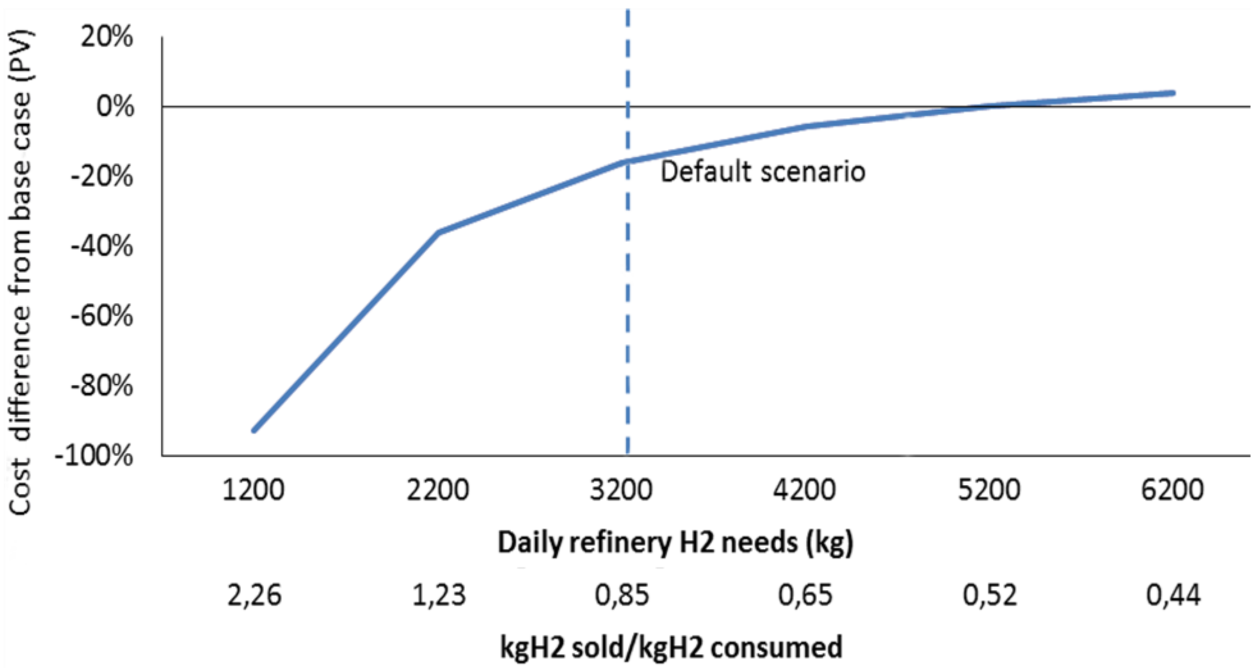


Figure 6-16: Difference of PV of all costs when varying the ratio of H2 sold/H2 consumed for semi-centralised scenario

As shown, more kg sold for every kg consumed, results in an increase in profit or the refinery. The ratio has to be at **least 0.52 kg sold for every kg consumed**, for the semi-centralised case to provide any economic advantages over the base case. For this model, this means that the refinery could consume up to 5,200 kg/day, (or 22 MW of installed electrolyser capacity) given the sales volume it currently has. Any further increases in its consumption, would result in a net loss, unless sales to other businesses increase.

6.3.2 Glass/Steel

Table 6-7: Sensitivity analyses performed for the glass and metallurgy industries

Expense type	Parameter	Range			
		Default	Min	Max	Reason
CAPEX	Daily needs	Glass: 300 kg/day Steel: 1050 kg/day	Glass: 200 kg/day Steel: 650 kg/day	Glass: 400 kg/day Steel: 1450 kg/day	Include larger or smaller industries in study
OPEX	Electricity costs (base costs)	Glass: 0.084 €/kWh Steel: 0.065 €/kWh	Glass: 0.04 €/kWh Steel: 0.03 €/kWh	Glass: 0.12 €/kWh Steel: 0.09 €/kWh	Greatest cost parameter of P2H scenarios, possible cost reductions

Daily hydrogen demand

A sensitivity analysis was run to test the effects of the daily demand of the industry. As shown in Figure 6-17, the cost difference between on-site electrolysis and the base case closes for larger daily needs, due to scaling up of the electrolyser. However, it is not enough to make on-site electrolysis an attractive investment option for the glass industry. The semi-centralised scenario costs are increasing proportionately to the daily demand, at the same rate as the base case and therefore the difference between the two remains constant. At higher consumptions, a very small decrease (<1%) takes place due to the minor scale up in the refinery.

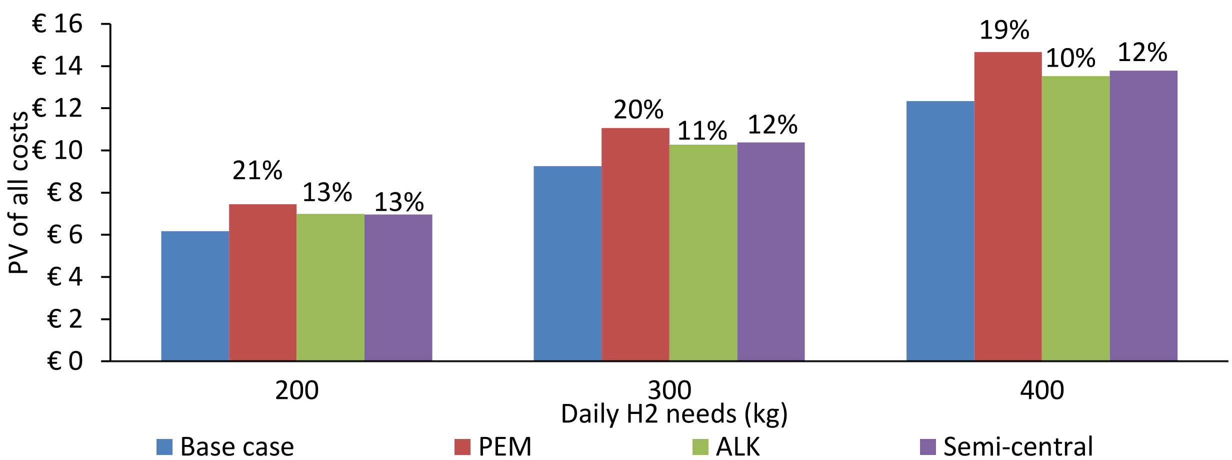


Figure 6-17: PV of all costs for all scenarios for various daily demands for the glass industry

The same behaviour is exhibited in the steel industry. Here however, the semi-centralised scenario shows again a small, but noticeable decrease in costs when the daily hydrogen needs increase. Increasing the demand by 400 kg/day at the steel plant, significantly affects the refinery's P2H production scale. As shown in 6.3.1, scale up reduces the costs at the refinery.

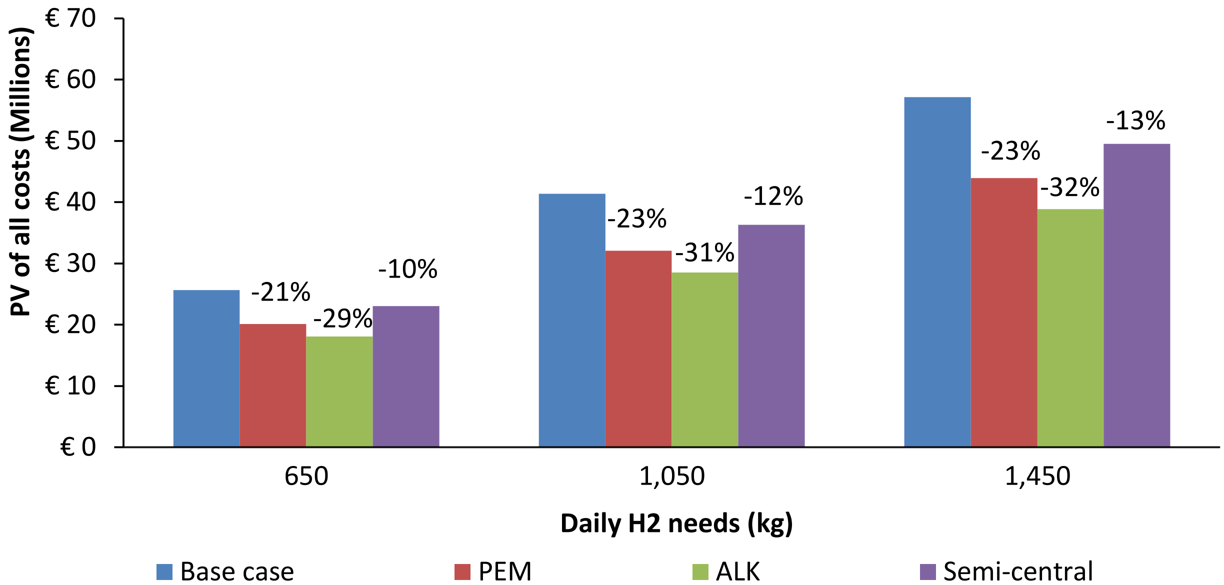


Figure 6-18: PV of all costs for all scenarios for various daily demands for the steel industry

Again the on-site ALK is the most profitable scenario. As shown in chapter 5, the OPEX is much lower compared to the base and semi-centralised case and that contributes to the very low overall costs.

Electricity costs

As with the case of the refinery, the electricity cost is the most important factor to hydrogen production. Here, the base and semi-centralised NPVs remain the same, since no electricity costs are considered.

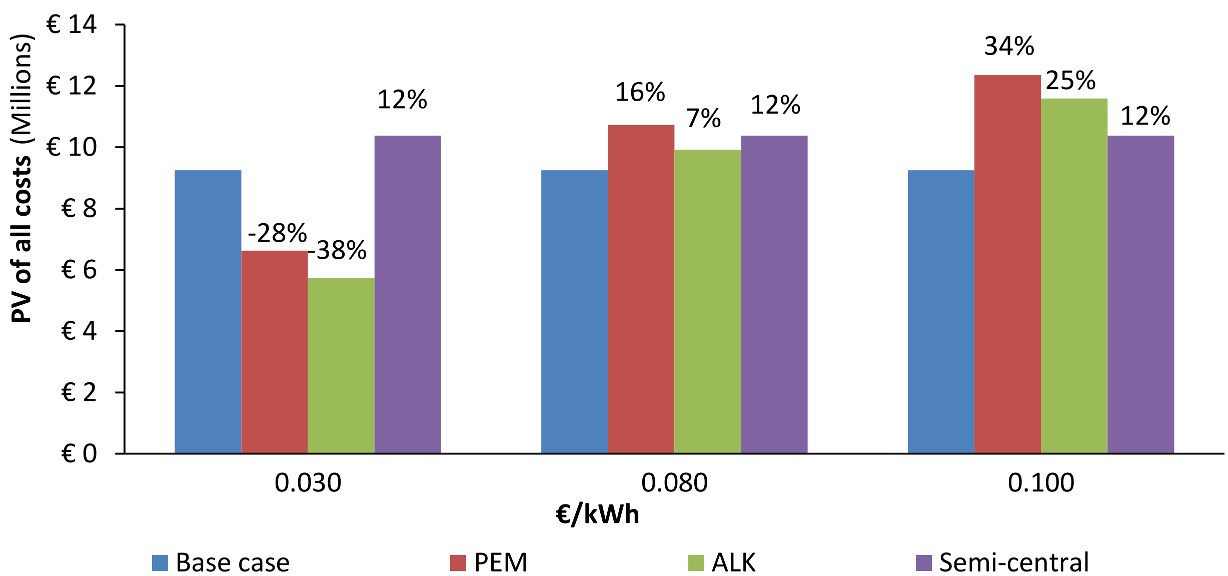


Figure 6-19: PV of all costs for all scenarios for various electricity prices for the glass industry

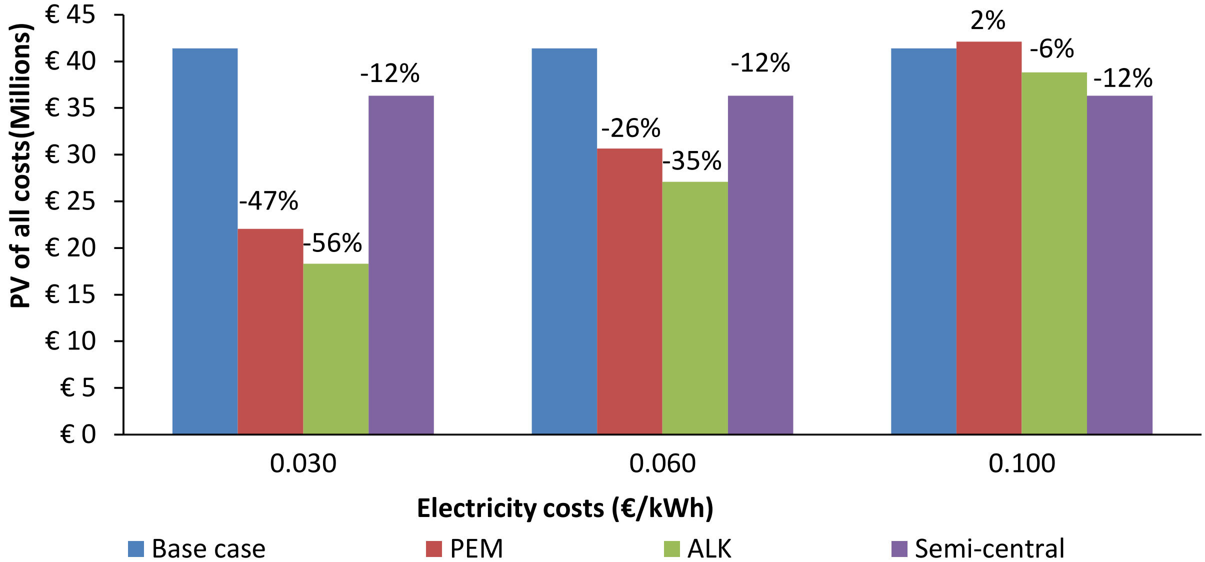


Figure 6-20: PV of all costs for all scenarios for various electricity prices for the steel industry

For both the glass and steel industries the semi-centralised model becomes more attractive for higher electricity price rises, since the price of hydrogen from the refinery remains the same while the costs of on-site production increase.

Table 6-8 shows the electricity prices for which the different P2H scenarios breakeven with the base case for the glass and steel industry.

Table 6-8: Cost of electricity for P2H scenarios to breakeven

	Breakeven costs of electricity	
	Glass	Steel
PEM	62 €/MWh	97 €/MWh
ALK	72 €/MWh	108 €/MWh

Again, no breakeven electricity price was calculated for the semi-centralised system since its costs are (mostly) not affected by the electricity prices.

6.3.3 Forklifts

For the fleet of forklifts, one of the parameters considered was the cost of the fuel cell module that replaces the battery, because of the spread of values in literature as well the potential it has to reduce over the years. Then, we considered the electricity cost, since it still one of the most important factors of the operational expenses. Finally the impact of the size of the fleet was calculated by changing the amount of forklifts operating in the warehouse.

Table 6-9: Sensitivity analyses performed for the forklift fleet

Category	Parameter		Range		
		Default	Min	Max	Why?
CAPEX	Fuel cell stack cost	€30,000 per forklift	€20,000	€40,000	Greatest share of upfront costs. Large variation in literature Costs of stacks are dropping.
OPEX	Electricity costs (base costs)	70 €/MWh	35 €/MWh (-50%)	105 €/MWh (+50%)	Greatest cost parameter of P2H scenarios, possible cost reductions
Other	Fleet size	100 forklifts	50	200	Relevant to scale of equipment and therefore total costs per forklift.

Fuel cell module cost

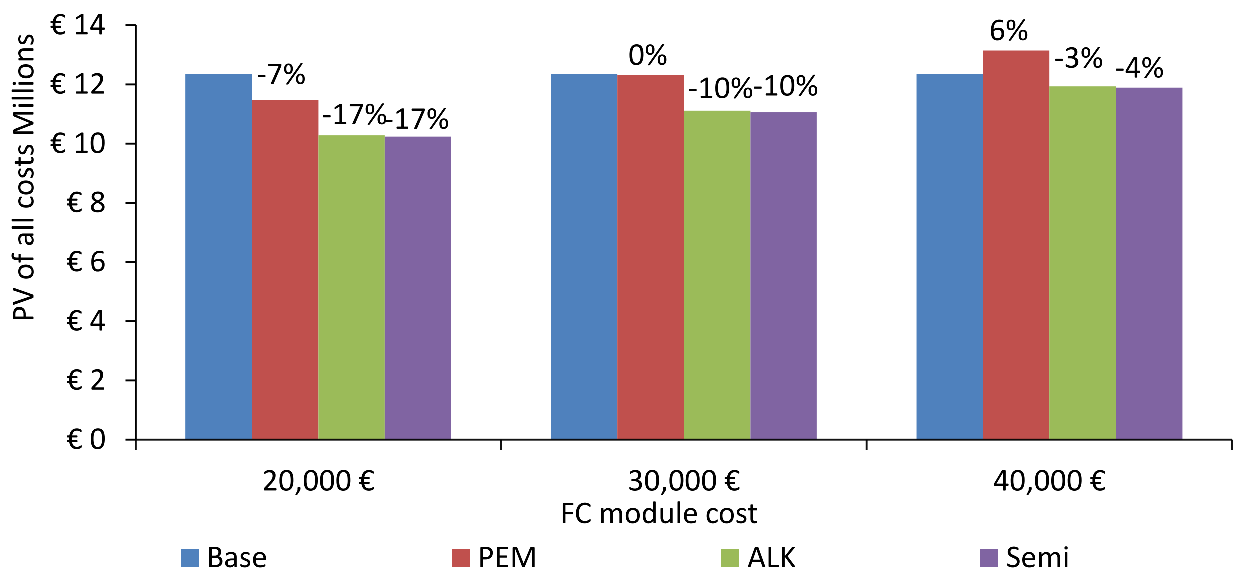


Figure 6-21: PV of all costs for all scenarios for various fuel cell module costs

The fuel cell modules cost is the most important cost factor for the case of the forklifts, even surpassing the cost of the electrolyser for the PEM and ALK scenarios.

A reduction of about 30%, to 20 k€/module, makes the fuel cell forklifts more profitable than the battery electric variants. A 30% change in the costs of the modules, changes the NPV by 8% on all P2H scenarios, showing the importance of this parameter as it is a large cash flow taking place in Year 0 and therefore it is undiscounted.

Electricity costs

As before, the electricity costs are an important sensitivity analysis as they represent the cost of feedstock in P2H scenarios.

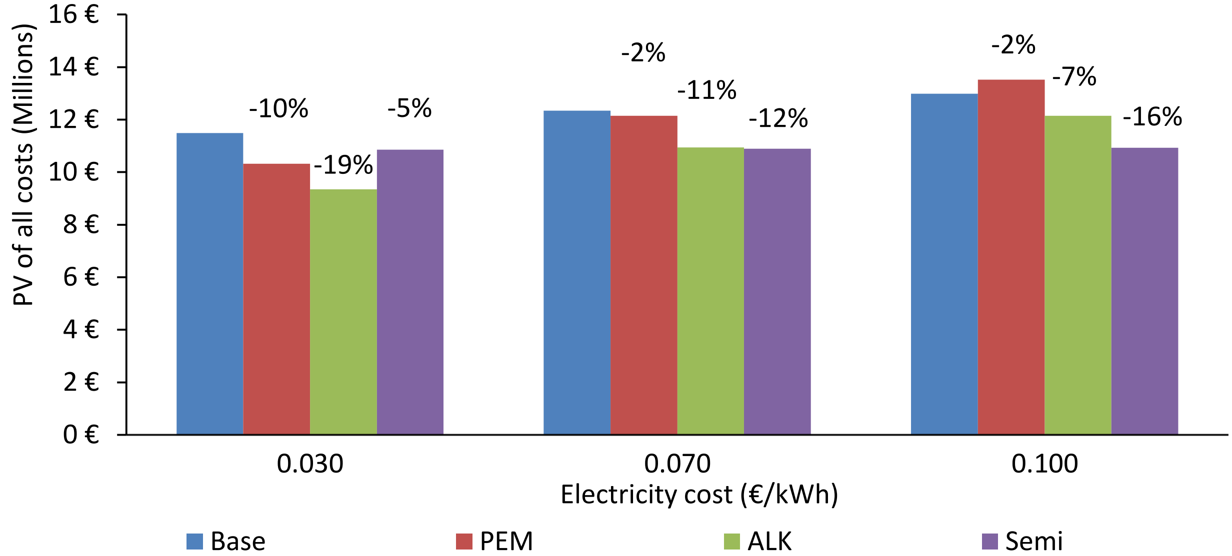


Figure 6-22: PV of all costs for all scenarios for various electricity prices for the forklifts

As shown in Figure 6-22, the fuel cell forklifts with on-site hydrogen production using an ALK electrolyser, prove to be a more profitable investment than the battery electric ones for low electricity prices. In particular, as shown in Table 6-10, electricity price must be below 150 €/MWh for FC forklifts with ALK electrolysis to be an attractive investment for a warehouse operator. The cost difference from the base case, decreases for the semi-centralised scenario as the electricity prices rise.

Table 6-10: Breakeven prices for P2H scenarios for forklifts

Scenario	Electricity price to breakeven with the base case
PEM	80 €/MWh
ALK	150 €/MWh
Semi-central	- €/MWh

Forklifts fleet size

The scale of operations affects the size of the electrolyser, as well as the costs of hydrogen production per kg. Figure 6-23 shows that the P2H scenarios become more profitable compared to the base case as the amount of forklifts increases.

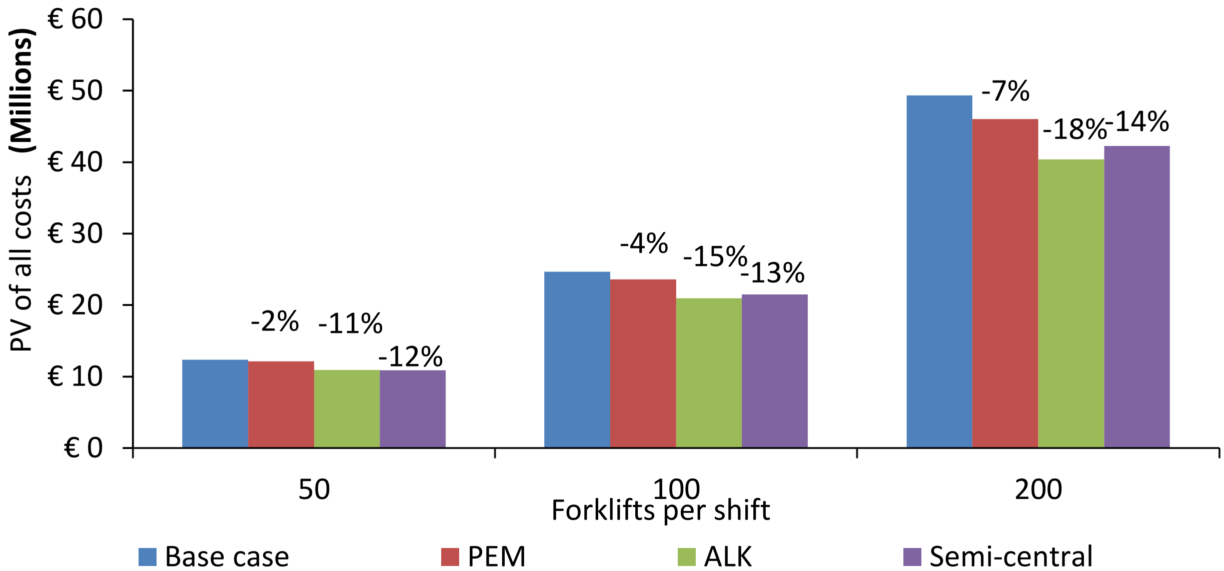


Figure 6-23: PV of all costs for all scenarios for various fleet sizes for the forklifts

As the number of forklifts in the fleet increases the on-site scenarios reduce their relevant costs much more than the semi-centralised scenario. The PEM scenario becomes unprofitable for less than 35 lifts, the ALK for less than 15 and the semi-centralised, for less than 8.

6.4 Vans/trucks

For the vans and trucks fleets of the system the main cost parameter was the cost of the vehicles that was assumed to be 3 times the cost of the diesel equivalent vehicle. A sensitivity analysis was performed for both the initial purchase of vehicles and for their replacement after 10 years as there is large uncertainty about this cost.

Table 6-11: Sensitivity analyses performed for the vans/trucks fleet

Expense type	Parameter		Range		
		Default	Min	Max	Why?
CAPEX	Cost of vehicles	300% of the diesel variant	100%	300%	Greatest share of upfront costs. Costs of stacks are dropping.
OPEX	Diesel cost	1.2 €/L	1.0 €/L	1.5 €/L	Most important OPEX in the base case

Vehicle purchase cost

The most important cost in the case of the vans and trucks is the upfront costs of the vehicles. For the default scenario, a price 3 times higher than a diesel equivalent vehicle was assumed and for the sensitivity analysis the CAPEX was changed again with respect to that.

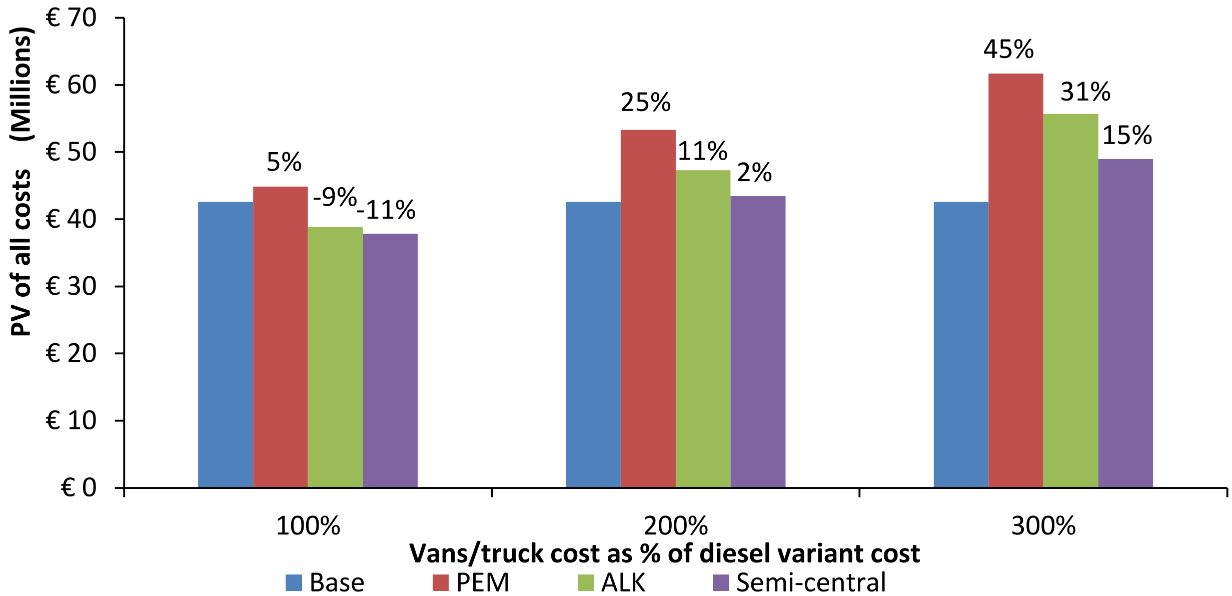


Figure 6-24: PV of all costs for all scenarios for various FCV costs (% of diesel vehicles CAPEX)

Figure 6-24 shows how the vans/trucks CAPEX affects the investment. Note that this includes the replacement costs after 10 years. In the most extreme case, where the cost for a fuel cell vehicle is the same with a diesel vehicle, on-site production using an alkaline electrolyser is 9% more cost effective than the base case, while the semi-centralised scenario saves about 11% from the base case. The breakeven vehicles costs are presented in Table 6 -6-12.

Table 6 -6-12: Breakeven vehicles costs for the different scenarios

	Relative cost price to diesel vehicles	Price	
		Vans	Trucks
Base case – Diesel	0 %	34,000 €	80,000 €
PEM	73 %	24,723 €	58,171 €
ALK	144 %	49,029 €	115,363 €
Semi-central	114 %	38,928 %	91,595 €

Diesel costs

The fuel costs contribute the most to the annual OPEX and therefore reduction would negatively affect the fuel cell vehicle scenarios.

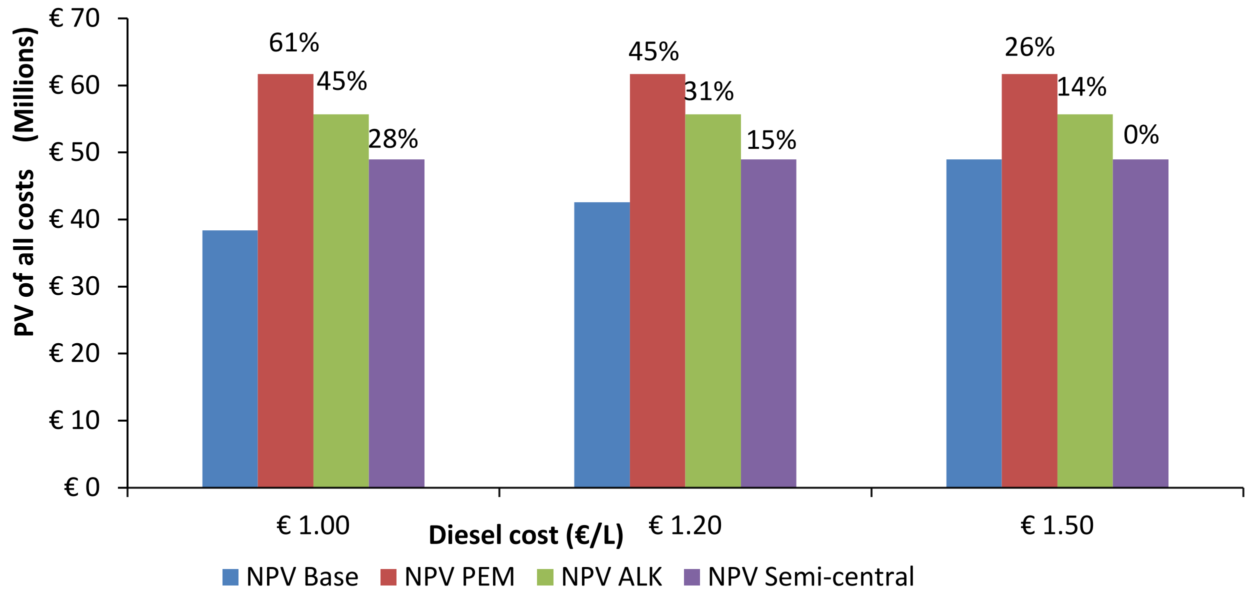


Figure 6-25: PV of all costs for all scenarios for various diesel prices – vans/trucks

Indeed as shown in Figure 6-25, a decrease of the diesel price by 0.1 €/L increases the relative losses of the P2H scenarios by about 6-7% sfor all the scenarios. An equivalent increase has of course the exact opposite result, but the fuel cell commercial vehicles case are still not profitable. Together with the sensitivity analysis for the FCV CAPEX, it is then easy to draw the conclusion that the fuel costs, although important, are not the major factor in the profitability of the hydrogen vans and trucks. Breakeven prices are presented in Table 6-13.

Table 6-13: Diesel price for P2H scenarios to breakeven with base case

	Diesel price (€/L)
PEM	2.10
ALK	1.82
Semi-central	1.50

We need a conclusion section here with a collective table showing all your conclusions. For all cases, for all sensitivities (if one factor was proven not to affect the results then you can emit it).

Spend some time and though on this. It is important.

6.5 Conclusions

Below, the conclusions of the sensitivity analysis are presented in for every industry. Certain parameters that proved to be of lesser importance have been omitted.

Refinery

Table 6-14: Sensitivity analysis conclusions for every industry

Discount rate	High impact over economics of investment. Lower rates favour the semi-centralised model over the base case which breaks even at ≈10%.
Electrolyser maintenance	Despite being an important part of the total costs of the investment, for values within the range that literature suggests, semi-central scenario remains the most profitable P2H scenario
Electricity price	Lower prices reduce overall costs and gap between each scenario and base case. Breakeven prices: • PEM: 12.8 €/MWh • ALK : 30.8 €/MWh • Semi-central : 57.9 €/MWh
ETS	Small changes (±20 €/tonne) have a major impact on results, however, prices above 100€ are necessary for an on-site scenario (no H2 sales) to show profitability over the base case.
Daily hydrogen needs	Higher demands reduce cost difference between base case and ALK/PEM scenarios. For the semi-centralised model, sales must increase on-par with the refinery's consumption, to retain the cost $sold_{H2}/consumed_{H2}$ ratio above 0.52.

Glass and steel industries:

Daily hydrogen needs	Higher daily demands, favour all of the P2H scenarios.
Electricity costs	On-site P2H installation profitable only for very low (<28 €/MWh) electricity prices in glass. Semi-central costs are unaffected by the by electricity prices at the glass/steel plant.

Forklifts

Fuel cell module cost	Important parameter of profitability. Breakeven costs at 27k€ and 18k€ per module for ALK and semi-central scenarios respectively.
Electricity costs	Most crucial in determining forklift propulsion (FC vs battery) and also hydrogen production method (semi-central vs on-site). • <70 €/MWh → FC with ALK • >70 €/MWh → FC with semi-central delivery

Vans and trucks

Vehicle purchase cost	Most important cost factor. ALK and semi-central break even only if final cost of FC vehciles is less than 150% their diesel variant.
Diesel fuel cost	Higher diesel prices improve the economics of P2H. Costs reduction of 5-6% per 10 ct€/L increase. Breakeven (ALK and semi-central) for prices <≈1.9 €/L.

7 Conclusions and future work

7.1 Conclusions

In this study an economic evaluation was performed regarding the application of Power-to-Hydrogen (P2H) technology in an industrial region, consisting of different types of industrial plants (oil refinery, glass and metallurgy plants) and logistics companies (warehouse with forklifts and van/truck fleet). Two different hydrogen supply methods were modelled – on-site electrolysis and semi-centralised electrolysis. Then these were compared to a base case scenario that simulates the current economy of such an industrial area.

7.1.1 Cost comparison for each industry type

Refinery:

For the case of the refinery, the analysis showed that on-site generation and consumption of hydrogen using P2H is an unattractive option for expanding the hydrogen production capacity of the plant. The costs over the lifetime of the investment exceeded 70% and 30% if PEM or alkaline electrolysers are used respectively.

In the case of the semi-centralised system, the refinery also produces the hydrogen required by all the other companies in the system. If the sales of this additional hydrogen are taken into account, the refinery's overall costs are 13% lower compared to the base case scenario. Moreover, because renewable refinery is used to produce hydrogen instead of reforming of natural gas, the refinery's emissions are reduced by 277,000 tonnes of CO_2 over the 20 years of the investment. In a favourable electricity price environment, with costs of electricity at 30 €/MWh (instead of 50 €/MWh assumed as default), the overall costs could be reduced by almost 50% compared to the base case scenario.

Glass and steel industries:

The glass industry, as modelled in this study, cannot benefit economically from the adoption of P2H as the costs are increased by 20% and 11% in the cases of on-site electrolysis using a PEM or alkaline electrolyser respectively. The semi-centralised model results in 12% higher costs for the glass, providing a viable option for adopting green hydrogen if a company is willing to bear some extra costs

The steel plant assumed in this study, does however see benefits from integrating green hydrogen in its production. On-site generation of hydrogen using a PEM or alkaline electrolyser results in 23% and 31% lower costs, respectively, over the lifetime of the investment, compared to the base case scenario. Reductions in electricity prices reduce even further the costs with 47 and 56% cost reduction for PEM and alkaline electrolysis, respectively. The semi-centralised model, has almost 12% higher costs than the base case, regardless of the steel industry's electricity prices.

Forklifts

The forklifts fleet, in the base case scenario use batteries, while in the hydrogen scenarios converts to fuel cell electric forklifts. If the production of the hydrogen takes place on-site, the costs decrease by 2% and 11%, for PEM and alkaline electrolysis, while in the semi-central scenario the cost are 12% lower than the base case scenario. For lower electricity prices than the ones assumed as default in this study (70 €/MWh) the hydrogen forklift conversion along with on-site production becomes especially more attractive than, while for higher electricity prices the semi-centralised model offers lower costs than all of the alternatives.

Vans and trucks:

For the vans and trucks fleet, due to the lack of any available commercial examples an estimation of the cost of fuel cell vehicles was made, at 3 times the cost of their diesel equivalents. Because of this very large capital cost difference, a conversion of the fleet to hydrogen fuel cells, results in 45% or 31% cost increase of the lifetime, if PEM or alkaline electrolysis is chosen, respectively. In the case of the semi-centralised model, the costs are only 15% higher than the base case scenario. To make a business case out of hydrogen fuel cell vehicles for light and heavy duty road transport, along a hydrogen production cost decrease – mainly through electricity price reduction – the costs of the fuel cell vehicles would have to approach those of diesel at approximately 1.5 times the cost of a similar diesel vehicle.

7.1.2 Overall comparison of different P2H investment scenario costs:

Table 7-1 presents the costs of the base case scenario in million € and the relative difference of the P2H scenarios. This overview, shows that, the minimum costs for transitioning to renewable hydrogen in an industrial area, are achieved when the hydrogen is produced through a semi-central production model, although this might not seem like the optimal choice for individual investors.

By replacing hydrogen production from fossil fuels, diesel powered commercial vehicles and battery electric forklifts the overall costs of the industrial area are reduced by 3.3%. For the system studied in this analysis, this translates to almost 5 million € over 20 years.

Table 7-1: Costs of the base case scenario for every industry of the system and relative cost difference for the P2H scenarios

	Base case cost (million €)	On-site costs		Semi-central costs
		PEM	ALK	
Refinery	42.1	+72%	+32%	-13%
Glass	6.5	+20%	+11%	+12%
Steel	35.6	- 23%	-31%	-12%
Forklifts	21.3	-2%	-11%	-12%
Vans/Trucks	42.6	+45%	+31%	+15%
System	**148.2**	**+29%**	**+9.6%**	**-3.3%**

As a result of such a transition, the overall CO_2 emissions can be reduced by approximately 25,000 tonnes/year, or 500,000 tonnes over the lifetime of the investment, as presented in Figure 7-1.

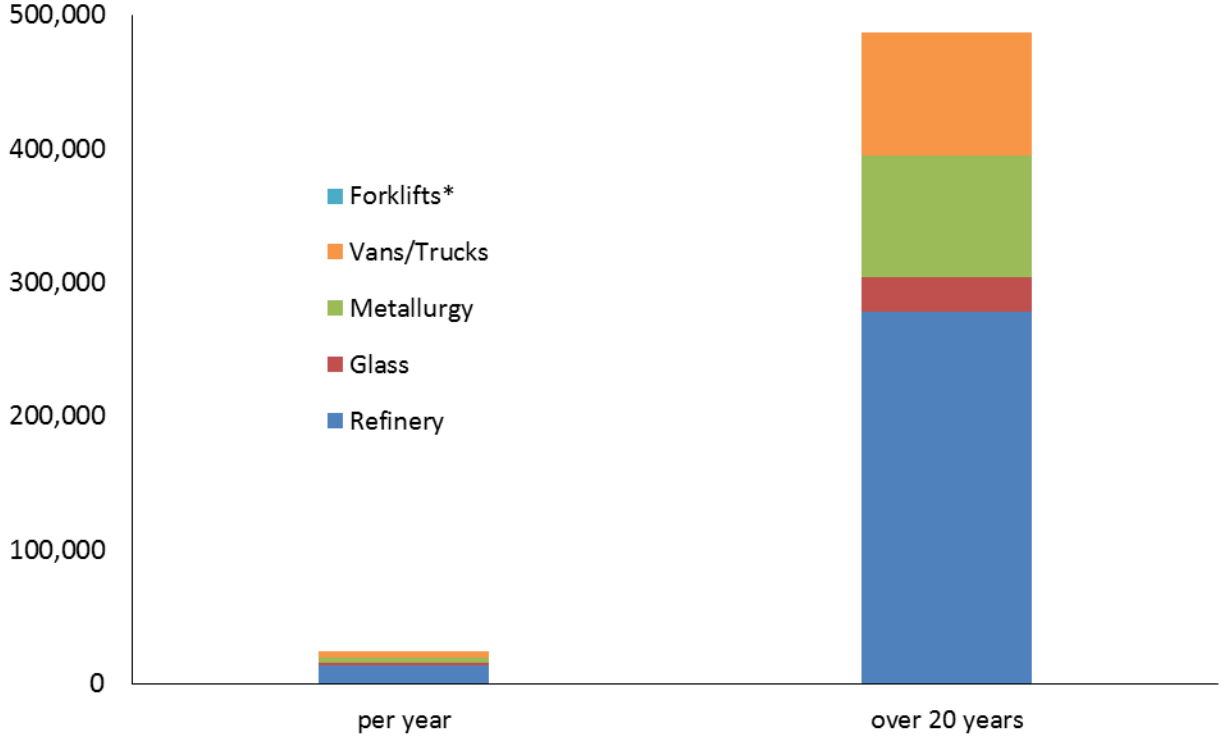


Figure 7-1: CO2 emissions (tonnes) avoided for every company of the industrial area per year and over the investment lifetime

Furthermore, as the hydrogen is produced only at the refinery and the transportation costs are kept to a minimum, in the case of more favourable electricity prices, the costs of electrolytic hydrogen reach very low levels, slightly higher than those of a central methane reforming facility. Figure 7-2 shows the electrolysis costs per kg of hydrogen, for electricity prices of 30 €/MWh. In such a scenario the cost of electrolysis approaches 2.6 €/kg_{H2}.

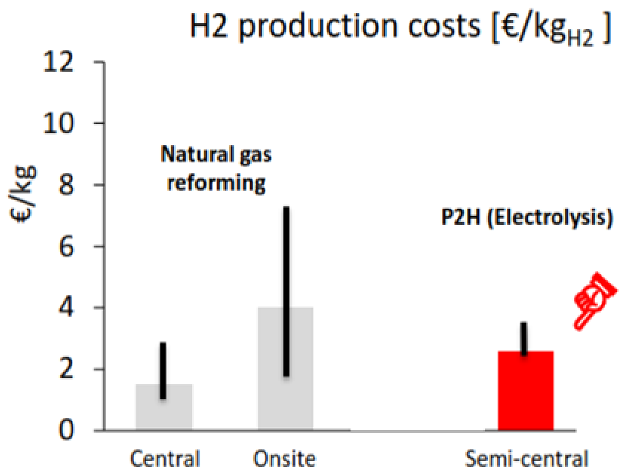


Figure 7-2: Costs of semi-central electrolysis (for refinery electricity prices 30 €/MWh)

7.2 Future Work

In this study specific types of companies have modelled, using average values from the available literature and creating a generic European industrial region.

To study more accurately the benefits of hydrogen in an industrial region and specifically the impact of a semi-centralised model, dedicated case studies for each specific European industrial region would be necessary. Also in this study, the companies considered, especially in the logistics sector (forklifts, vans/trucks) had rather large fleet. A system with multiple smaller fleets should be examined as in many industrial areas smaller logistics warehouses exist as well, and for these cases on-site hydrogen generation would be economically unattractive due to very small scale.

For the analysis of the commercial road vehicles as well as the forklifts, the results and the sensitivity analysis have shown that the cost of the fuel cell technology is critical to the profitability of renewable hydrogen as fuel. Although future cost reductions in fuel cell technology were estimated and used analysis, the author acknowledges that the eminent massive uptake of FC vehicles could potentially trigger a more drastic cost reduction an efficiency improvement. In this respect, future work could include the re-evaluation of specific components of this model, after the further experience with fuel cells is acquired, especially, in the road transport industry.

As it was shown in many instances of this study, electricity was one of the most important cost parameters for any company and any scenario. A promising way to reduce the cost of electricity is to participate in a dynamic electricity market where the prices of electricity change multiple times within the day. Such a system would require careful sizing of the electrolysers as well as an optimisation of their operation schedule to meet both the necessary daily demand while operating only during the lowest electricity cost periods.

The cost of electricity is also affected by the relevant regulatory framework that imposes taxes, fees or levies on top of the actual cost of the commodity. Currently, to the author's knowledge, renewable hydrogen production through electrolysis, is not subject to any special electricity pricing or reduction.

Changes in this respect will change the dynamics of the model and should be further studied, should they occur.

Regulation can also increase the cost of polluting industrial activities through mechanisms like the ETS or increased road taxes for diesel vehicles. As stricter laws are applied, a re-evaluation of the cost of P2H for industrial applications would be necessary.

7.3 Recommendations

7.3.1 Recommendations to industries

According to the results of this study, a transition to renewable hydrogen production is not a prohibitively costly investment under certain circumstances. It is advised, that industries create a local network where a large producer takes over the hydrogen supply of a whole area. Possibly under the form of a consortium of companies, this network will help alleviate the increased high costs for early adopters as well as reduce the risks associated with new, innovative investments, while greatly reducing their carbon footprint.

It is also advised that logistics companies seeking to reduce the costs of labour while increasing the available space in their warehouses, look into the conversion of their battery forklift fleets to hydrogen fuel cells. Especially, companies with low priced electricity available (<60 €/MWh), should further research the prospective of installing an electrolyser on-site. Companies with increased costs of battery charging due to high electricity prices (<100 €/Mwh), could join other local enterprises in consortiums, as described above, to create a semi-centralised green hydrogen system.

7.3.2 Recommendations to regulators

It is essential that the regulatory framework changes in order for electrolysis and semi-central production models to function.

First and foremost, electricity intended for the production of renewable fuel or feedstock must be governed by a specific rule set, that partially reduces or completely removes taxes and fees that burden the final price.

Furthermore, regulators should move forward with the establishment of a certification process for green hydrogen. Although this effort has been initiated with the CertifHy project, it is imperative that to make it a requirement for green hydrogen production facilities. The creation of a market for guarantees of origin (GoO) for green hydrogen, would not only create additional revenues for the producer but also detach the “renewable” character of hydrogen from the actual product. As a result, the “renewable nature” of hydrogen would be sold separately from the actual product, leading to potential customers outside the industrial area, where the transportation of green hydrogen would be uneconomical.

It is also very important, that this type of investments, that deal with the creation of whole local economies, rather than small individual cost saving investments, are incentivised through funding, tax/fees reduction and bureaucratic support. As descried in the previous chapters, CAPEX is a very important part of the investment and organisations like the Fuel Cells and Hydrogen Joint Undertaking (FCH-JU) that fund such projects, should starting dealing with regional projects involving different types of industries.

7.3.3 Recommendations to Toyota

Toyota has already launched products for the logistics industry, in the form of fuel cell modules for forklifts as well as a working prototype of a hydrogen fuel cell heavy truck. The results of this study, show the cost objectives for these products, to make them competitive alternatives to mainstream forklifts and trucks.

Fuel cell modules for forklifts should be brought to a final cost around 20 k€/module to ensure that hydrogen as a forklift fuel is an attractive option for warehouse operators. Heavy and light commercial vehicles cost targets should be below 2x the cost of their diesel equivalents or below 50k€ for FC vans and 115k€ for trucks, in order for early adopters to face a reasonable additional cost. Promoting such products in areas of high industrial activity either though targeted marketing or forming consortiums with relevant companies, would kick-start a large demand for hydrogen fuel, further motivating third party production and refuelling infrastructure development.

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