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Impact of Electrolysers on the Network

Part of the Aberdeen Hydrogen Project

Research Report

November 2016

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Contents

1. Introduction

The use of fuel cell electric vehicles (FCEV) powered by hydrogen has the potential to compete with fossil fuelled vehicles in the foreseeable future. The UK H2Mobility Project [1] predicts that there could be over 1.6 million such vehicles in the UK by 2030, involving public transport, goods and private vehicles. For FCEV to be a viable alternative to conventional fossil fuelled vehicles, a reliable supply and storage/dispensing infrastructure for hydrogen will be required. UK H2Mobility suggests that 51% of required hydrogen will be produced by electrolysers in 2030. FCEV do not produce any direct carbon emissions; however the production of hydrogen through electrolysis requires electricity. This increased demand for electricity will place additional demands on the electricity network which may initiate a need for network reinforcement. Network reinforcement can be costly, time consuming, and disruptive to local communities.

The Scottish Government's 'Electricity Generation Policy Statement – 2013' sets out a target of delivering the equivalent of 100% of Scottish gross electricity consumption from renewables by 2020. There is growing consensus that the electricity network needs to become more flexible to accommodate this move to a lower carbon generation mix. The National Infrastructure Committee report published earlier in 2016 identifies three sources for this flexibility – increased interconnection, energy storage and demand side management. Electrolysers can provide both energy storage and demand side management and could offer significant benefits by providing grid-balancing services, which could allow the deployment of additional renewable generation and may alleviate network constraints. It is clear that the ability of electrolysers to be integrated with renewable technologies needs to be better understood to realise these potential benefits.

The "Impact of Electrolysers on the Distribution Network" project was commissioned to establish if it is possible to manage the production of hydrogen by electrolysis such that the need for network reinforcement is reduced, delayed or removed, and also to investigate the impact on renewable generation output where electrolysers are integrated with renewable technologies.

Scottish and Southern Electricity Networks (SSEN) operated as a partner in the Aberdeen Hydrogen Bus Project which included the design, construction and operation of a Hydrogen Refuelling Station (HRS) located in the Kittybrewster area of Aberdeen.

SSEN developed a control system to run trials on the Kittybrewster HRS. Through the trials a series of network scenarios were simulated including demand-constrained and generation-constrained networks. The capacity of the electrolysers to operate flexibly in response to network, generation, and economic signals was also investigated and the outcomes of these trials are contained in this report.

Through the development and implementation of these trials it was important to recognise that as the HRS is a fully operational site, the key and overriding requirement was to ensure that enough hydrogen was available to meet the refuelling needs of the ten hydrogen fuel cell buses that were operating across Aberdeen as part of the Aberdeen Hydrogen Bus Project.

1.1 Aberdeen Hydrogen Bus Project

The Aberdeen Hydrogen Bus Project (AHP), which has backing from public and private sector organisations from the UK and Europe, was delivered as part of the Aberdeen City Council's H2 Aberdeen initiative. The Project established the first commercial-scale hydrogen production and bus refuelling station in the UK, the Kittybrewster hydrogen refuelling station (HRS), to fuel ten hydrogen buses in operation in Aberdeen City [2].

The Impact of Electrolysers on the Distribution Network project received Ofgem Low Carbon Networks Fund (LCNF) Tier 1 and Network Innovation Allowance (NIA) funding to undertake additional testing at the Kittybrewster HRS to specifically identify the risks and opportunities to the network associated with any future uptake of this technology in the UK.

The AHP has been co-funded by Scottish, UK and European partners including Innovate UK, Scottish Government, Scottish Enterprise, Fuel Cells and Hydrogen Joint Undertaking (FCHJU) through the High V.LO-City and HyTransit projects, Aberdeen City Council, First, Stagecoach, SSEN, and SGN. BOC has invested £1 million in the hydrogen production and refuelling station constructed at Kittybrewster.

1.2 Overview of Kittybrewster Hydrogen Refuelling Station

The physical arrangement of the plant at Kittybrewster in Aberdeen city includes three Hydrogenics Hystat™60 electrolysers (hydrogen generator units) [3], two hydrogen compressors, two hydrogen dispensers, hydrogen storage and associated control systems and cooling plant. Hydrogen is dispensed under pressure to fuel a fleet of ten buses which operate on scheduled routes around Aberdeen. This equipment is described in more detail in the sections below.

1.2.1 Compressor and dispensers

The Linde IC 90 compressor takes gas at a maximum pressure of 30bar and compresses it, using multiple piston stages, to 500bar in this case. The maximum stated operating pressure is 1000bar and the maximum delivered flow rate is 33.6/67.2kg/h for single or double line units. The nominal power consumption is 2.7kWh/kg, corresponding to a power demand of 90/180kW.

1.2.2 Electrolysers

The filling station includes three Hydrogenics Hystat^{TM}60 alkaline electrolysers, each of which operates at approximately 80^{o}C and 10bar providing a maximum hydrogen flow rate of 60Nmt/h or 5.4kg/h. The power demand at this rate of production is stated as 312kW.

1.2.3 Storage

The onsite storage comprises 120 cylinders divided into three banks. All of the storage banks can be charged to 500bar.The system discharges H_2 from the tank with the lowest pressure required to fuel each bus, moving up to higher pressure tanks as required. This ensures that as the stores are depleted there is still high pressure H_2 available to fill the bus, as shown in Figure 1.1. The onsite storage feeds two hydrogen dispensers, each capable of providing a 30kg fill in approximately ten minutes. The layout is shown in Figure 1.2.

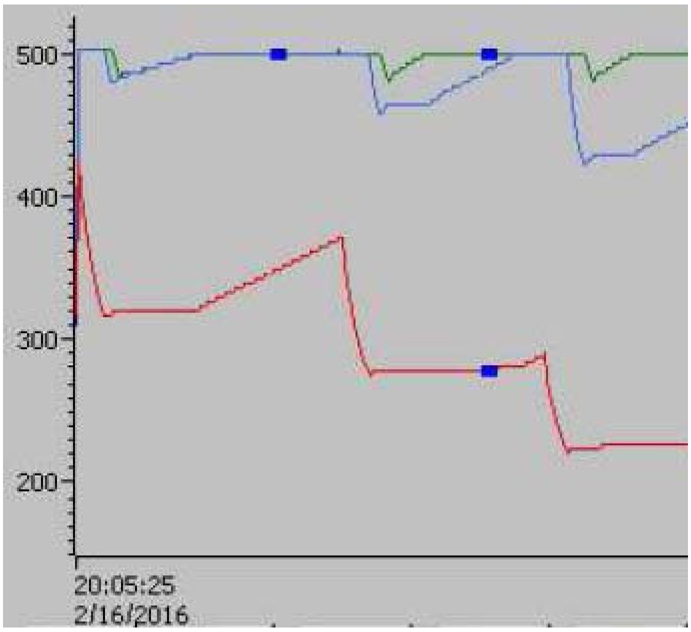


Figure 1.1: Screenshot (Courtesy of BOC) showing depletion of hydrogen storage. The system uses the lowest possible pressure to refuel the bus, taking only a portion from the high pressure tank.

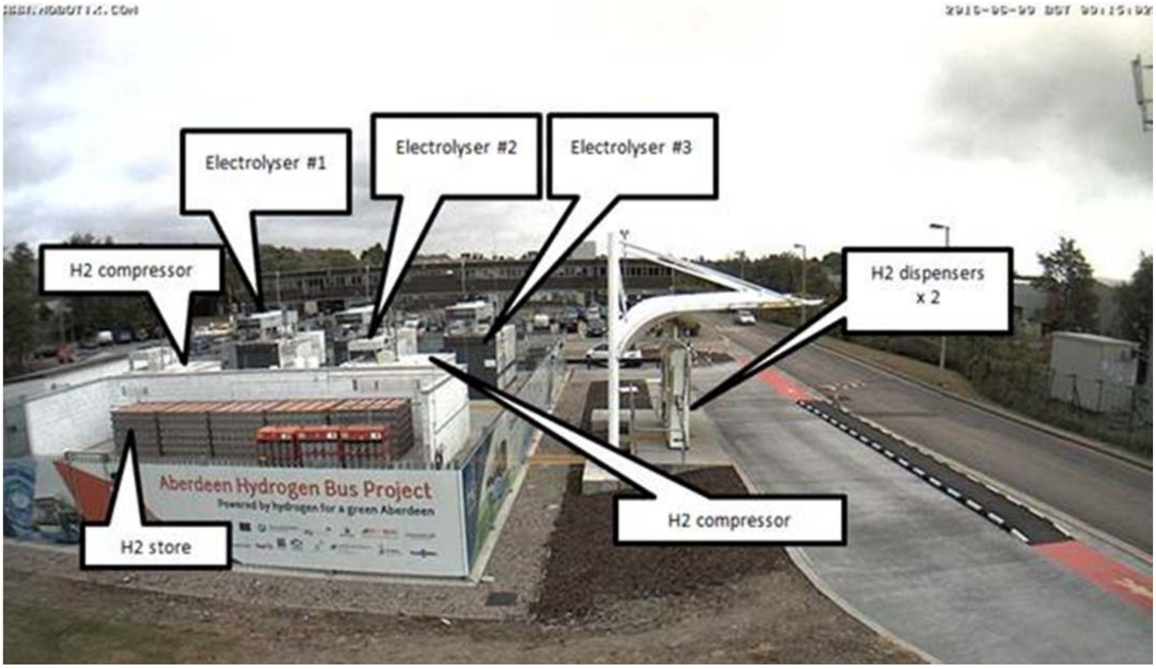


Figure 1.2: Kittybrewster filling station layout (image: Aberdeen City Council)

2. Predicted roll-out of electrolysers

To understand the scale of potential electrolyser deployment on the distribution network a review of the UK H_2 Mobility Project [1] was undertaken.

2.1 UK H_2 Mobility Project

Fuel Cell Electrical Vehicles (FCEV) provide the potential to decarbonise road transport, create new economic opportunities, diversify national energy supply, and reduce significantly the local environmental impacts of road transport. The UK H_2 Mobility project was established to evaluate the benefits of FCEV to the UK and to develop a roadmap for the introduction of vehicles and hydrogen refuelling infrastructure.

The roll-out of FCEV will depend on a successful commercialisation and will require the development of a hydrogen refuelling network to support FCEV and their sales..

2.1.1 UK market for FCEV

A number of analyses looked into the demand model and consumer analysis and some of the key findings include:

- **By 2030 a cumulative FCEV fleet of 1.6 million** vehicles can be achieved as the vehicles become cost-competitive and the Hydrogen refuelling station (HRS) network develops. Annual sales could exceed 300,000 p.a. by 2030.
- **Early demand will be driven by the 10% of the population** attracted to and willing to buy FCEV at the prevailing total cost of ownership. These early adopters would generate sales of FCEV in the UK of approximately 10,000p.a. by 2020.
- **Initial uptake rates, amounting to 13,000 vehicles in the first five years**, are limited by the cost of buying the vehicles. No subsidy for FCEV purchase or operation has been assumed in the roadmap. Accelerating demand in this period requires a substantial reduction in the premium of FCEV over diesel vehicles.
- The market growth predicted in the UK H2 Mobility roadmap implies a UK share of 10-15% of expected global FCEV sales.
- The expectations of the vehicle manufacturers and the consumer demand model show a strong correlation. **The demand curve is very similar to the experience of other new technology vehicles introduced in the past ten years**, e.g. petrol-electric hybrids: a slow take-up in the early years followed by acceleration thereafter as costs fall.

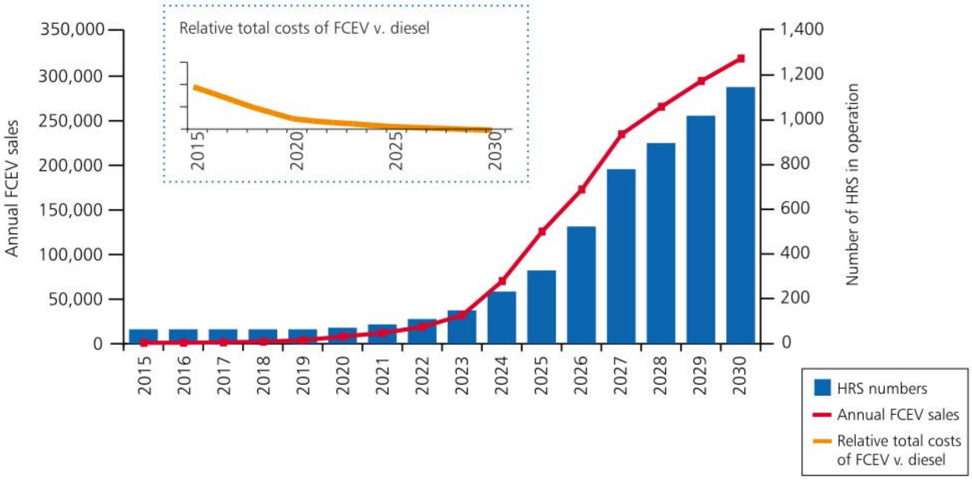


Figure 2.1 UK consumer demand for FCEV increases as the cost premium diminishes and the network of HRS expands [1]

2.1.2 Supplying the consumer with hydrogen

Convenient and accessible hydrogen refuelling stations (HRS) are critical for the FCEV uptake, as analysis shows that the availability of hydrogen and cost of ownership are consumers' primary concerns. The report indicated that consumers expected that the convenience of the HRS network would be similar to the diesel refuelling network. As shown in Figure 2.2, convenient access to HRS has a significant effect on customers' attitude towards FCEV.

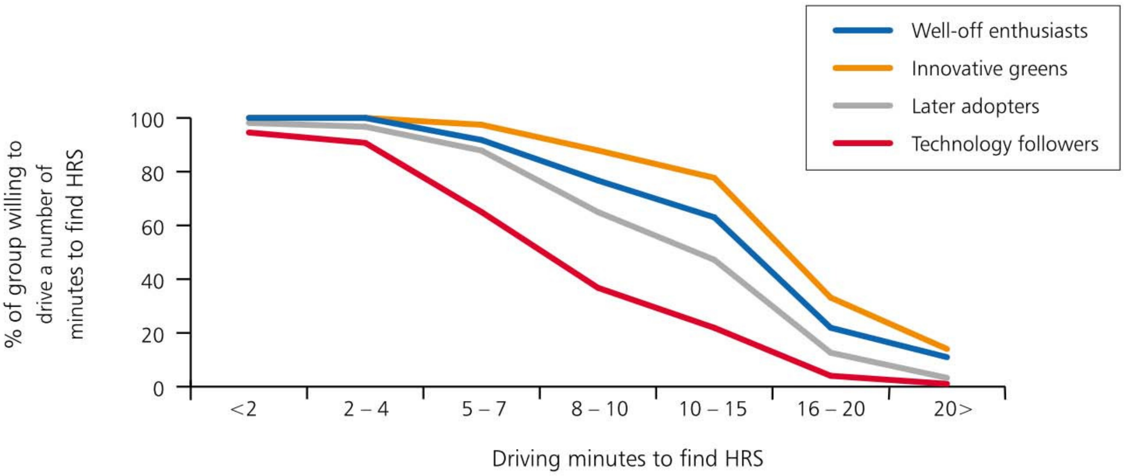


Figure 2.2 Early adopter groups are willing to drive further to refuel their FCEV than late adopters and followers [1]

As a suitable HRS network is crucial, the UK H2 Mobility project states that it is important to consider the following issues:

- Creating a network which provides accessibility for the maximum number of consumers.

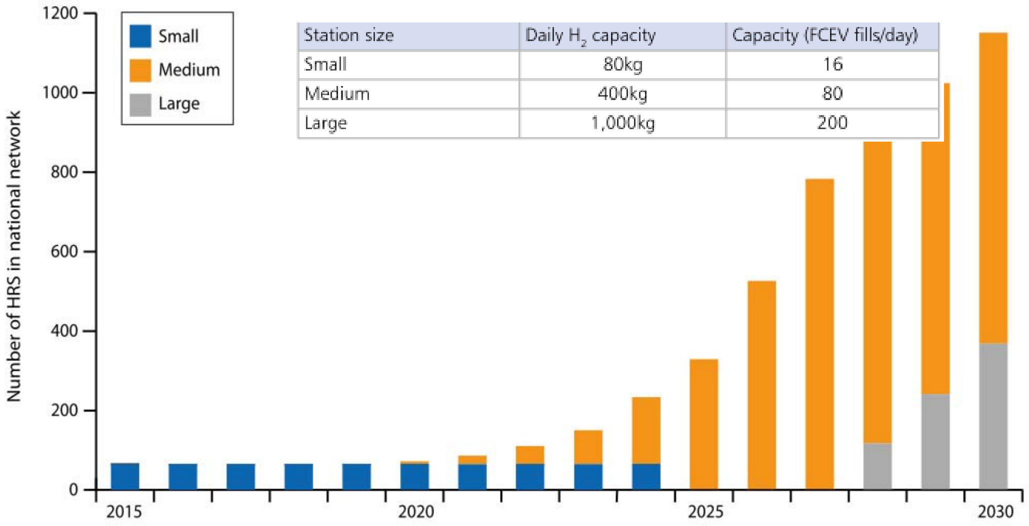
- Creating a network that delivers the best possible return on the up-front investment.

This means that successful roll-out of HRS network will need to cover the most populous areas in the UK and also key motorway and trunk routes. The development of this network should start from the outset as a “national” network of HRS, as this will enable both localised commuting, and weekday and weekend travel for the population, while crucially also providing for national travel for commercial vehicles.

Access to only one local HRS has been perceived as a significant inconvenience, which means that the successful HRS roll-out will require at least two, and in some instances more, HRS per Local Authority District (LAD).

An initial network of stations is necessary to get the market started, and a key finding of the UK H_2 Mobility project is that an optimised roll-out strategy involves introducing FCEV and HRS first in selected localities, with an initial minimum network of 65 stations across the UK in the right locations. This network would cover major population centres, and connecting motorways and A roads to enable national mobility. It is based on having a minimum of two HRS per LAD in the targeted regions, with 8km between HRS and within a ten minute drive.

As shown in Figure 2.3, the model indicates a need for the HRS network to grow to 329 stations by 2025 (with the appearance of medium size HRS), and to further expand to 1,150 stations by 2030 (when all of the HRS are predicted to be of the medium or large size). This would mean that all of the UK’s population would have access to an HRS (defined as having at least one HRS in their LAD). The majority would have access to more than one station locally, as shown in Figure 2.4.



Station size	Daily H_2 capacity	Capacity (FCEV fills/day)
Small	80kg	16
Medium	400kg	80
Large	1,000kg	200

Figure 2.3 The development of HRS (taken from the UK H2 Mobility roadmap).

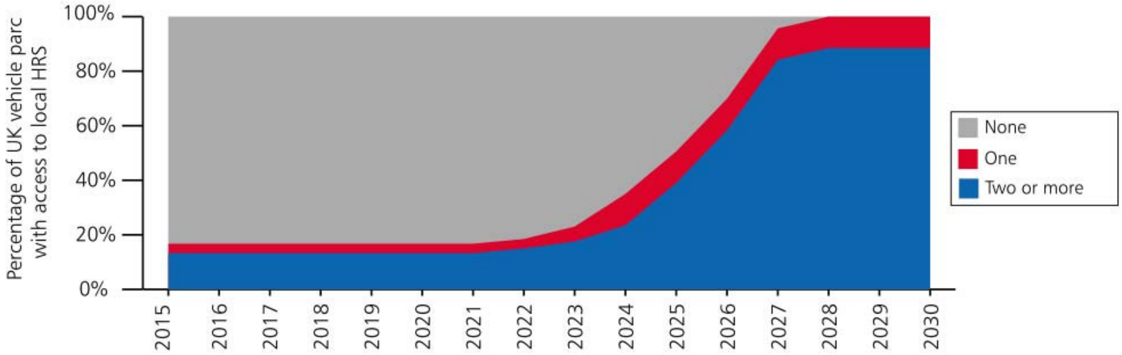


Figure 2.4 The development of local HRS network coverage in terms of the proportion of the UK vehicle fleet with access to zero, one and two or more HRS in their local district

2.1.3 The refuelling network map

With an estimated 51% of hydrogen being delivered by electrolysers, we can conclude that the roll-out of HRS could have significant impact on the power system network, as the electrolysers connect to the network. Figure 2.5 indicates the expected density of FCEV and location of HRS in 2030, which can be used to evaluate effects of rollout of FCEV and HRS on electricity infrastructure.

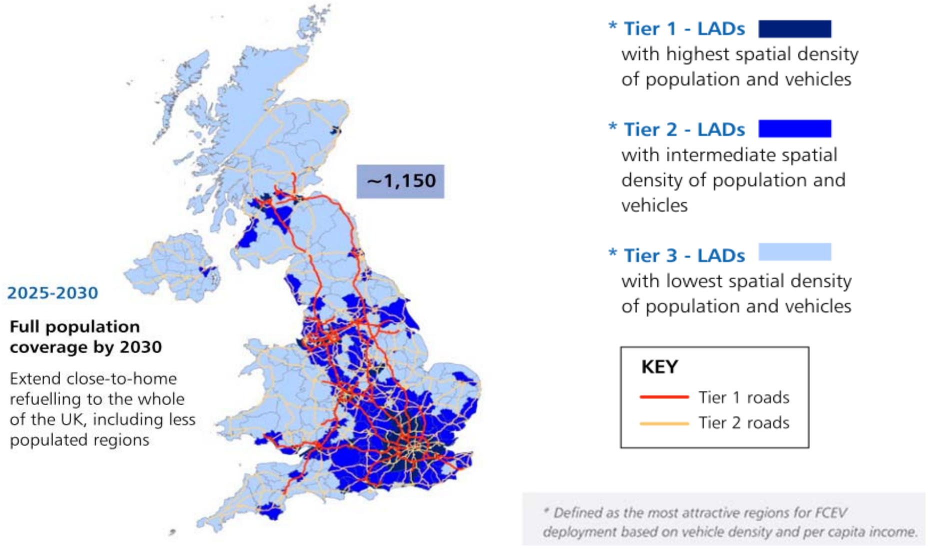


Figure 2.5 HRS network in 2030

It is expected that the HRS network will increase electricity demand, which may require network upgrades. However, as a number of projects, including this one show, electrolysers can be operated as a flexible load. Despite increasing network load, if appropriate Demand Side Management (DSM) schemes and pricing strategies are developed, hydrogen electrolysers can help mitigate network infrastructure investments and potentially provide services which could be used to help tackle other network issues such as improving renewable generation integration and participating in the provision of ancillary services.

3. Understanding the impact of electrolysers on the electrical distribution network

3.1 Method to evaluate the impact of HRS roll-out

One of the aims of modelling the impact of electrolysers is to study if the roll-out of HRS and FCEV across the UK (as described in Chapter 2: Predicted roll-out of electrolysers) will lead to additional requirements for network reinforcement.

The number of hydrogen FCEV has been estimated based on data published by the Office for National Statistics (ONS) [67], which summarises the number of vehicles available in each Local Authority District (LAD). It is estimated by UK H2Mobility report that there will be 1.6 million FCEV in the UK by 2030, with 51% of the hydrogen required produced by hydrogen electrolysers.

SSEN used this data to approximate the number of FCEV in each area by 2030. The analysis assumed that the 1.6 million FCEV would be distributed among LAD proportionally to the current car ownerships as per national statistics. The electrolyser connection requirements in a particular LAD can then be evaluated based on the estimated number of hydrogen vehicles and conclusions from the UK H2 Mobility report that successful HRS roll-out requires at least two HRS per LAD.

The potential impact of electrolysers was modelled by the University of Strathclyde (UoS) by adding an adequate number of electrolysers in a distribution network, as described above. Connecting points of electrolysers, i.e. hydrogen refuelling stations, in each of the representative local networks were selected to ensure convenience for customers, and were therefore chosen where possible to be at an intersection of main roads, and close to population centres. Furthermore, 2030 levels of the electricity demand in the network were estimated based on the SSEN Long Term Development Strategy (LTDS).

As described above, the evaluation methodology used in this project consists of the following steps:

- For the chosen LAD, determine the number of expected FCEV based on ONS data for car ownership.
- Determine the total number of electrolyser units and their sizes to provide sufficient hydrogen supply for the estimated number of FCEV.
- Select locations and connection points of HRS and distribute all electrolyser units determined in the previous step among these stations. The connection locations of the HRS are selected to be close to main roads or main road intersections, and to be close to population centres. To avoid reducing ability of the neighbouring LADs to serve their load, each of these sections of the networks were modelled as islands that could be served only from the substations located within the considered LAD. This

assumption provides a more critical case, but avoids potentially reducing the ability of the neighbouring LADs to supply FCEV on their territory.

- Evaluate how connections of the HRS affect system operation and network capacity.

The method was applied to two types of distribution networks urban network and semi-urban/rural at two instants in time: current (2016 demand), and future 2030 demand. In addition, each scenario was modelled with distributed generation running at maximum output and at zero output. The impact of electrolysers on the network is analysed by evaluating power flows and the need for the network upgrades is indicated by overloads.

3.2 Method to evaluate electrolyser operation for different objectives and constraints

3.2.1 Simulation system to run trials

While NREL tests [14] sought to evaluate physical characteristics of an electrolyser in the laboratory, and how quickly it could respond to variations in set-points, this project evaluated how operation of an electrolyser can be managed in an operational setting.

This project aimed to explore and develop operational practices to evaluate how future implementation of new equipment will impact on the distribution system, and how this can be managed. Scottish and Southern Electricity Networks (SSEN) has previously implemented a number of Active Network Management (ANM) schemes, where the variable output of renewable (wind) generators is managed in real time to ensure that network capacity is not exceeded. Through this mechanism network assets can be utilised better, resulting in reduced spending on network reinforcement and quicker connections for generators. These trials explored how electrolysers producing hydrogen can be used to act as a flexible demand, thereby providing a service to the electrical network to manage capacity or participate in energy and ancillary services markets.

3.2.2 Simulation set-up

Evaluation of how the electrolyser can respond to various technical and commercial requests has been tested via a number of trials which have simulated instructions to change a set point. The aim was to evaluate how the electrolyser would follow such outside signals instructing it to change its set-point, while also ensuring predefined hydrogen levels in the storage tanks would be met. The simulation control signals were determined using software supplied by SSEN and SGS, but the owner of the electrolyser (BOC) was able to override these simulation signals if it deemed that hydrogen targets would not be met, or if the level of hydrogen in storage went below pre-specified limits.

A high-level trial system diagram is shown in Figure 3.1.

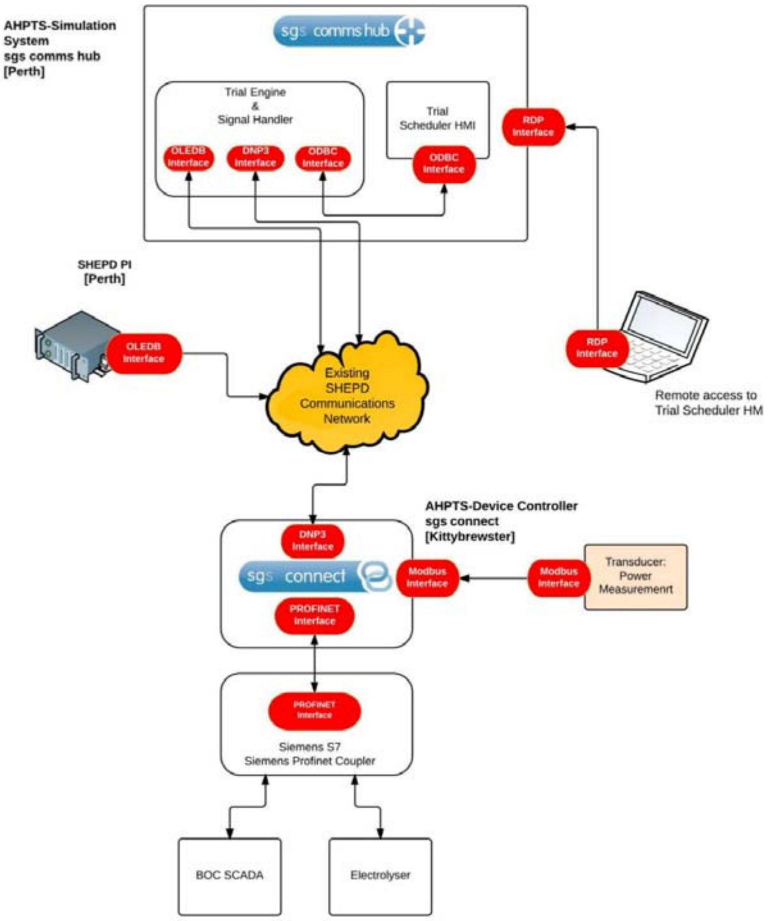


Figure 3.1 Aberdeen Hydrogen Project Trial System (AHPTS) [image: Smarter Grid Solutions]

The AHPTS consists of three components:

- The AHPTS-Simulation System, ("sgs comms hub") located at SSEN premises
- The AHPTS-Device Controller, ("sgs connect") located at the Kittybrewster site with the Electrolyser
- The AHPTS-Trial Scheduler application (HMI). The AHPTS-Trial Scheduler is a Windows application providing a user interface that allows authorised users to schedule Trials within the AHPTS. An operator can remotely login to the "sgs comms hub" to access the HMI.

The AHPTS-Simulation System itself consists of:

- The AHPTS-Trial Engine which runs the Trials, using data collected by the AHPTS-Signal Handler and passing a set point to the electrolyser, via the AHPTS-Signal Handler and AHPTS-Device Controller.
- The AHPTS-Signal Handler which is based on Smarter Grid Solutions' "sgs comms hub" platform to collect data from, and pass data to, the AHPTS-Device Controller and an OPC driver to collect data from the SSEN PI system.

3.3 Trial objectives and potential value

3.3.1 Introduction to trials

The electrolyser is operated under scenarios defined by SSEN to reflect potential future scenarios for HRS operation in the UK. The scenarios include operating the electrolyser to satisfy network condition limitations, to minimise operation during network peaks, and to use renewable energy resources to power the electrolyser. All of the scenarios must ensure that there is sufficient hydrogen supply for the ten hydrogen fuel cell buses that are running daily and require refuelling.

3.3.2 Electrolyser set points

The site at Kittybrewster has three individual electrolyser units. In the rest of the report the term 'electrolyser' is used to describe a single entity with the maximum power consumption of all three units, (excluding compressors and other balance of plant equipment). Table 1 summarises the range of set points available to the AHPTS when different numbers of electrolyser units are available. The minimum set point is 13.33% of the full capacity value.

Table 1 Electrolyser set points

Number of electrolysers available	**Maximum set point**	**Minimum set point**
3	100%	13.33%
2	66.7%	13.33%
1	33.3%	13.33%

3.3.3 Time of Use (ToU) pricing scheme

Under a Time of Use (ToU) energy price tariff, the energy price has different (pre-determined) values at different time periods of the day. This pricing scheme is used to entice flexible demand to shift operation from peak to off-peak hours. Typically, energy price during peak time periods will be higher while prices at night time will be lower.

For a number of trials, ToU was used as an incentive for the electrolyser to reduce its operational costs, while helping system operator reduce (or at least not significantly increase) the peak demand. The ToU pricing scheme used in AHP consists of four energy price bands: Red, Amber, Green, and Night. Red time period has the most expensive energy price, while Night has the least expensive value.

3.3.4 Scheduling of hydrogen production

Based on the above defined objectives, and considering all of the constraints, the aim of each simulated trial is to determine values of the set points that electrolyser should follow for the reminder of the trial, considering the level of stored hydrogen and other constraints, as defined by each of the trial or by technical limitations of the electrolyser. If the trial schedule is unable to meet H_2 demand during a trial the BOC system will take over control and revert to maximum production to ensure the bus demand is met; this may cause the HRS to operate during peak electricity hours and/or to breach a (simulated) demand constraint.

An example of a schedule to avoid breaching a demand constraint is shown in Figure 3.2.

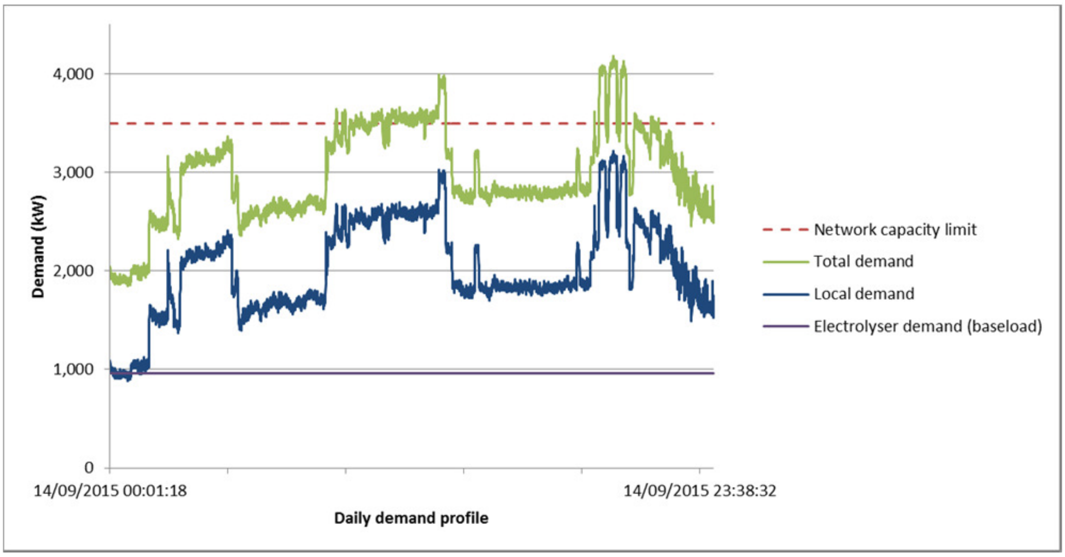


Figure 3.2 Local demand and additional electrolyser demand could breach local network limit at some periods of the day.

Flexibility provided by electrolysers that have storage capacity can allow the suspension or reduction of operation during peak periods. As shown in Figure 3.3, for the same daily demand profile the combined local and electrolyser demand can remain below the network capacity limit.

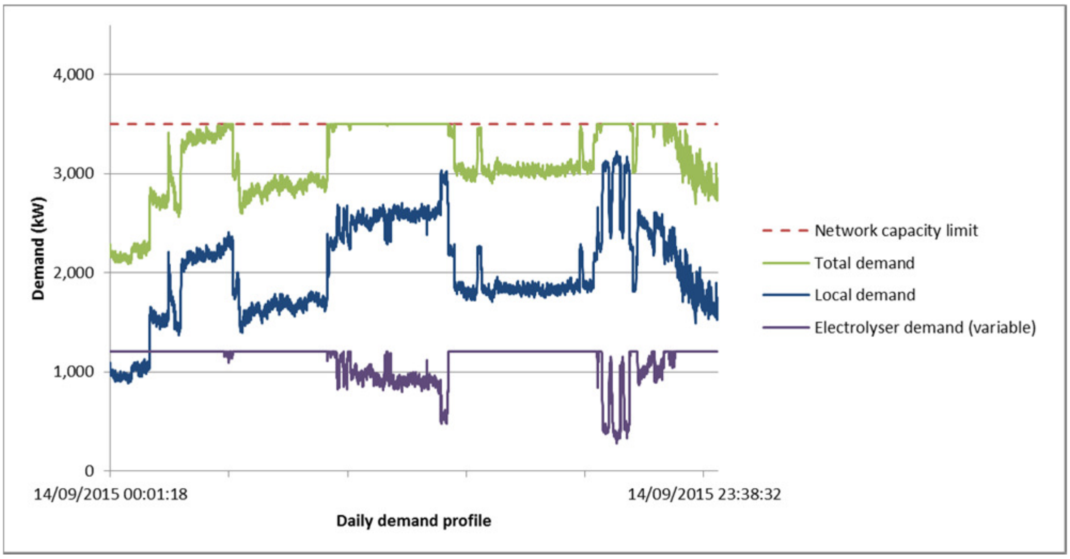


Figure 3.3 Electrolyser demand takes account of local demand to avoid breaching local network limit.

3.4 Trial types

The main constraints for each trial type are summarised in Table 2.

It is worth noting that the primary constraint on each trial was that the level of stored H_2 at the end of the trial period should match a specified target value. As the buses were able to refuel at any point during the trial, the electrolyser set-points were constantly re-calculated throughout the trials to ensure this level could be met in the remaining trial time. Where buses refuelled towards the end of the trial the electrolysers would be set to run using maximum available power, even if this fell during a Red pricing period. This characteristic would not occur during normal operation of an electrolyser and is specific to the trials.

Network limits were set to simulate demand or generation constrained networks. Data taken from a windfarm, a PV site, and the local substation were used to introduce constraints on available power. To protect the electrolyser from excessive cycling, a baseload of available power was implemented during some trials using renewable energy.

Table 2 Summary of objectives and constraints for the 12 project trials

Due to the similarity between trials 4/11 and trials 5/12, these have been grouped in the table

Trials	**Constraints**						
	Hydrogen Demand	Renewables output	Minimise Cost	Network Constraint	Local Demand	Follow Gas	Base load
Trial 1 **Demand management network constraint**	✔		✔	✔	✔		
Trial 2 **Cheapest H_2**	✔		✔				
Trial 3 **Gas flows**	✔		✔			✔	
Trial 4/11 **Maximise net wind/PV**	✔	✔			✔		✔
Trial 5/12 **Network constraint wind/PV**	✔	✔		✔			✔
Trial 6 **Demand management network constraint 2**	✔		✔	✔	✔		
Trial 7 **Wind farm tracking**	✔	✔					✔
Trial 8 **Earliest wind**	✔	✔					
Trial 9 **Max Wind & Fastest**	✔	✔					
Trial 10 **Off Peak & wind**	✔	✔	✔				

Trial 1 - Demand management network constraint

During Trial 1, the electrolyser is simulated to be placed in part of an electrical network where there is a demand constraint. The electrolyser set point is calculated so that the ‘available power’ to the electrolyser is restricted by the constrained network power supply. The forecast constraint is an average hourly value, and is used to create a H_2 production schedule to minimise cost, based on the TOU tariff.

Trial 2 - Cheapest H_2

Trial 2 schedules the electrolyser to minimise H_2 production cost (based on the ToU tariff). There is no limit on the power that it can use for hydrogen production at any time period - least cost of hydrogen production is the only aim of this trial.

Trial 3 - Gas flows

During Trial 3, the production of H2 must match the demand from a gas injection point, which is variable throughout the day. The H_2 production schedule is based on minimising H_2 production cost based on the ToU tariff.

Trial 4 - Maximise net wind

Trial 4 assumes that the available power to the electrolyser follows the output profile of a simulated wind farm with an associated local electrical demand. There is no wind forecast data for this trial. The power from the wind farm is used to fulfil the local demand, and any excess power from the wind farm (the ‘spill’) is used to operate the electrolyser. A baseload is in place to avoid cycling of the electrolyser if available power dips below the minimum required to operate. This means that even if there is no ‘spill’ power available the electrolyser will continue to produce hydrogen at a low rate.

Trial 5 - Network constraint (wind)

Trial 5 assumes that the available power to the electrolyser follows the output profile of a simulated wind farm where there is a local generation constraint. Hence, there will be times when the wind farm is unable to operate at full capacity. During Trial 5, the electrolyser will be run at times when the wind farm would normally be constrained in order to take up the excess capacity from the wind farm. If the excess capacity falls below a set base load value then the electrolyser will continue to operate at the base load level.

Trial 6 - Demand management network constraint 2

Trial 6 is similar to Trial 1, where the operation of the electrolyser is based on a locally constrained power supply. The electrolyser set point is calculated so that the ‘available power’ to the electrolyser is restricted by the constrained network power supply. The forecast constraint is a maximum hourly value (rather than average), and is used to create a H_2 production schedule to minimise cost, based on the TOU tariff.

Trial 7 - Wind farm tracking

Trial 7 assumes that the available power to the electrolyser follows the output profile of a simulated wind farm (without any local demand). There is no wind forecast data for this trial. A baseload is in place to avoid cycling of the electrolyser.

Trial 8 - Earliest wind

During Trial 8, the electrolyser is run at full capacity until the predicted output from the forecast wind generation is sufficient to generate the remainder of the required H_2.

Trial 9 - Max wind & fastest

During Trial 9, the electrolyser is scheduled to run at full available power capacity only during the forecast periods of maximum wind generation.

Trial 10 - Off peak & wind

For Trial 10, the electrolyser runs at full capacity during off peak hours (i.e. Green pricing). During peak hours (Red and Amber price bands), the electrolyser is powered solely by the wind farm. There is no forecast data.

Trial 11 - Maximise net PV

Trial 11 is the same as Trial 4, except it uses power from a PV solar farm rather than a wind farm.

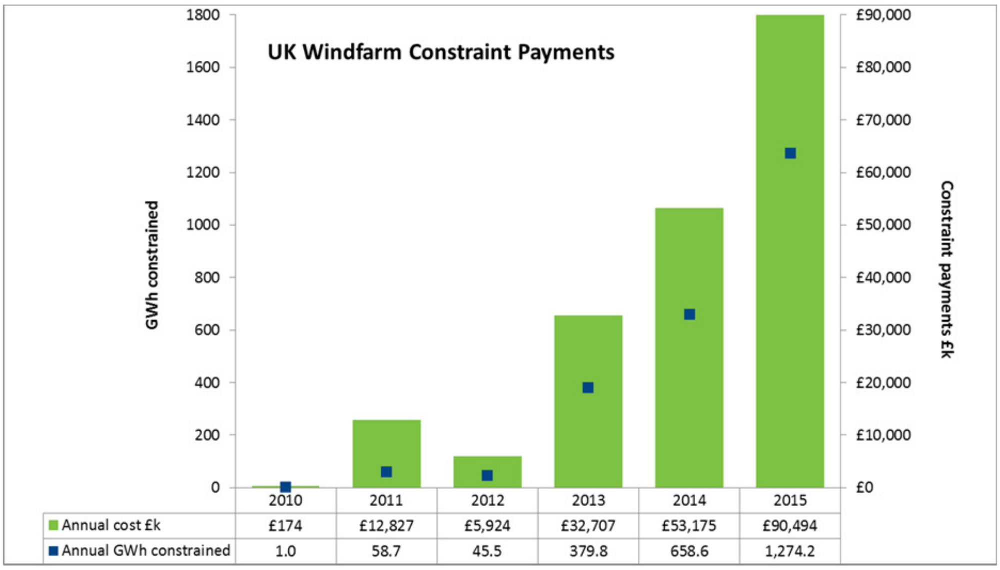
Trial 12 - Network constraint PV

Trial 12 is the same as Trial 5, except it uses power from a PV solar farm rather than a wind farm.

3.4.1 Trial Benefits

A number of the trials were designed to help increase utilisation of renewable generation such as wind and PV. For example, the electrolyser can consume excessive renewable power to avoid wind/PV curtailments. As Figure 3.4 illustrates, the UK made constraint payments of £170k in 2010. The trend of increasing renewable generation curtailment and constraint payments led to 877GWh of energy curtailed in 2015, with associated curtailment payments of £90.5 million [69]. Electrolysers could be used to increase demand during periods of high renewable generation so that these payments could be reduced.

Trials 1, 2 and 6 all seek to minimise the cost of running the electrolyser, so they benefit the electrolyser owner by lowering the overall cost of operation, and the end-user who will pay less for the product. Trials 1 and 6 also schedule the electrolyser under a demand constrained network and thus may enable deferral or avoidance of network reinforcement.



	2010	2011	2012	2013	2014	2015
🟩 Annual cost £k	£174	£12,827	£5,924	£32,707	£53,175	£90,494
■ Annual GWh constrained	1.0	58.7	45.5	379.8	658.6	1,274.2

Figure 3.4 Constraint Payments UK [69]

The remaining trial types are linked to renewable resources and could result in benefits including a reduction in constraint payments, avoidance of network reinforcement and faster connection for generation customers, improved use of network assets (allowing higher utilisation during periods of low demand/high renewable generation) which can reduce overall network charges to all customers.

3.4.2 Trial execution

The 12 Trials were conducted over an eight-month period, and aimed to understand the impact on DNOs if the roll-out of this technology becomes more widespread.

Within each of the trials the operation of the electrolyser is given via the calculation of set points.

Depending on the trial, network capacity, real-time data from a local demand, a gas injection supply point, historic wind farm and PV data are used as inputs for scheduling purposes. In addition, Time of Use (ToU) pricing is applied to several trials where a commercial aspect is considered.

The amount of hydrogen stored is monitored during the scheduling process in order to ensure the hydrogen supply is adequate. If the level of hydrogen goes below a predefined lower level, the BOC control system overrides any trial in progress to implement maximum hydrogen production. This procedure is terminated once the hydrogen storage reaches a predefined upper level.

The results for the trials undertaken are divided into successful and unsuccessful trials. The criteria for a successful trial include:

- Trial control time greater than 10% of the total trial duration. This is the time where an override is not in place due to low H_2 storage levels, so the trial is being controlled by SSEN.
- The amount of hydrogen generated during the trial is greater than 5kg. This removes any trials where, due to limited demand from the buses, there was minimal requirement to actually run the electrolyser.

The number of successful and unsuccessful instances for each of the 12 Trials is shown in Figure 3.5. At the beginning of the project we experienced a relatively high number of unsuccessful trials as we developed our understanding of the impact of bus fills on the control strategy.

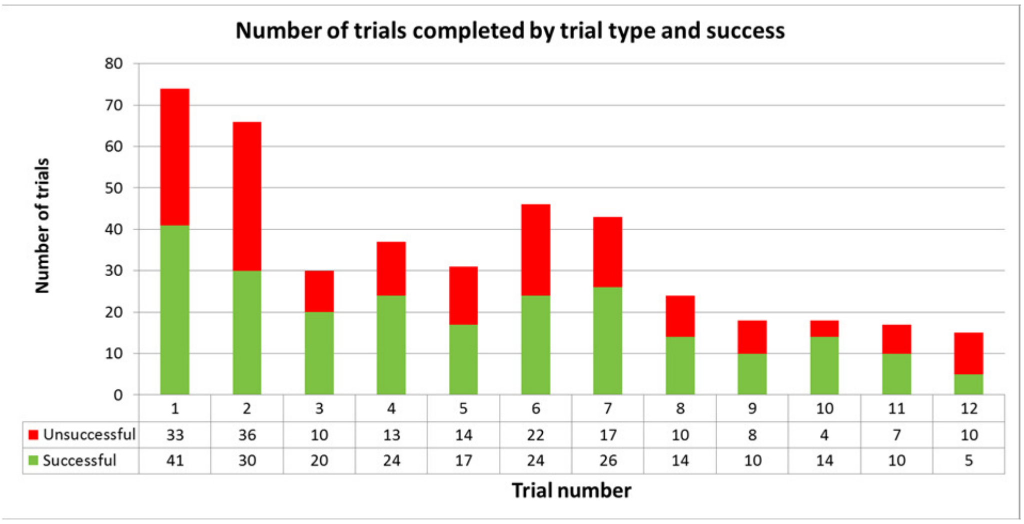


Figure 3.5 Number of trials completed by trial type and success

3.4.3 Weekly data analysis

Figure 3.6 summarizes the amount of hydrogen generated in each calendar week for a period of 2015 and 2016 and Figure 3.7 shows the number of buses refilled during the same period. As expected the amount of hydrogen produced mirrors the demand of the buses.

The average hydrogen generated during the successful trials was around 740kg for one calendar week. The lowest hydrogen generation in one week was 115kg, while hydrogen production was above 1000kg during other weeks; this is directly linked to the amount of hydrogen required by the fuel cell buses running daily in Aberdeen area. Discrepancies in the amount of hydrogen produced do occur where we have experienced unsuccessful trials during the week, where hydrogen was produced under control of BOC.

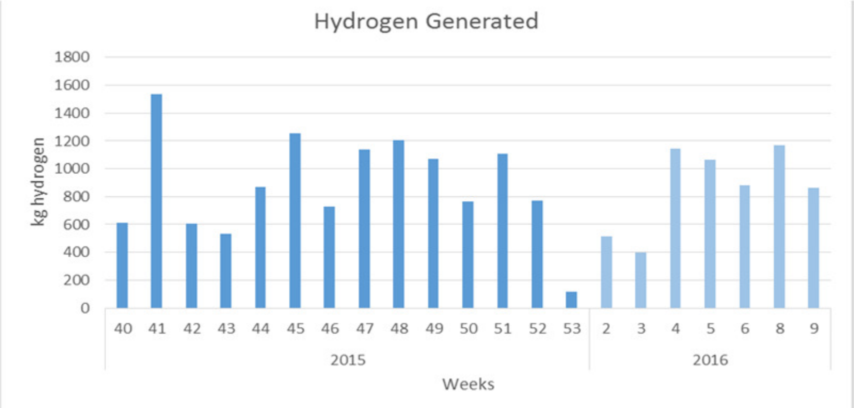


Figure 3.6 Summary of hydrogen generated by calendar weeks

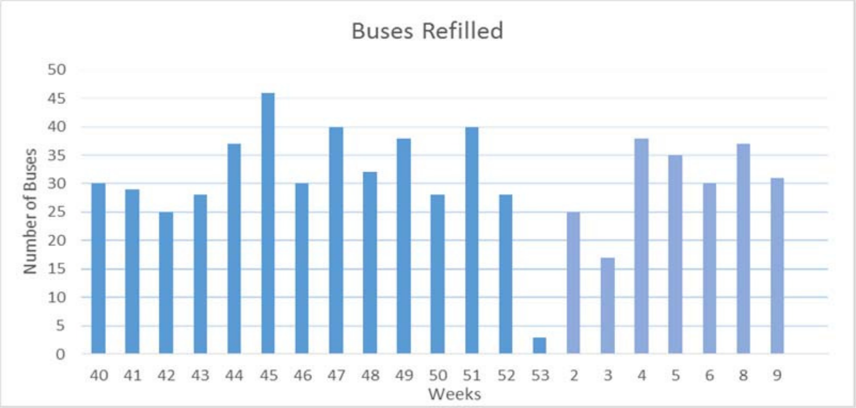


Figure 3.7 Summary of number of buses refilled by calendar weeks

The efficiency indicates how much energy has been used to produce one kilogram of hydrogen. This is shown in Figure 3.8 for each trial type. The average efficiency across all trials (following removal of outliers) was found to be 69.3kWh/kg.

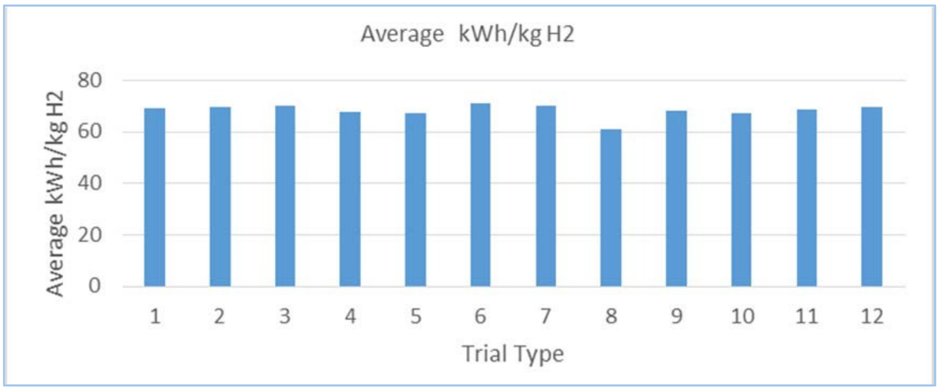


Figure 3.8 Summary of average power requirement by trial type

3.4.4 Utilisation

The utilization indicates the percentage of time that hydrogen production is controlled by the scheduler compared to the total trial time period. The average utilisation of all the successful trials is around 41%. The utilisation reflects the total time where the electrolyser was producing hydrogen under control by SSEN. A low utilisation figure reflects trials where hydrogen production is low (due to low demand or unsuitable conditions), or where hydrogen storage has dropped below a pre-set level leading to an override of the system by BOC.

Trials with a utilisation figure less than 10% are deemed 'unsuccessful'.

3.4.5 Variance

The average variance between the set point issued to the electrolyser and the actual power consumed by the electrolyser is summarized Figure 3.9. The difference between the set point issued and the actual measured power is mainly caused by the power consumed by compressors and other circuit components linked with the electrolyser. Moreover, a large variance can be caused by the BOC automated override, which ignores system set-points when the hydrogen levels fall below a set level. Also, for those trials which have no baseload level configured to prevent electrolyser cycling, the measured power finds it hard to follow frequent on/off of set points in a cycling period, and this can also lead to variance between the set point and actual power.

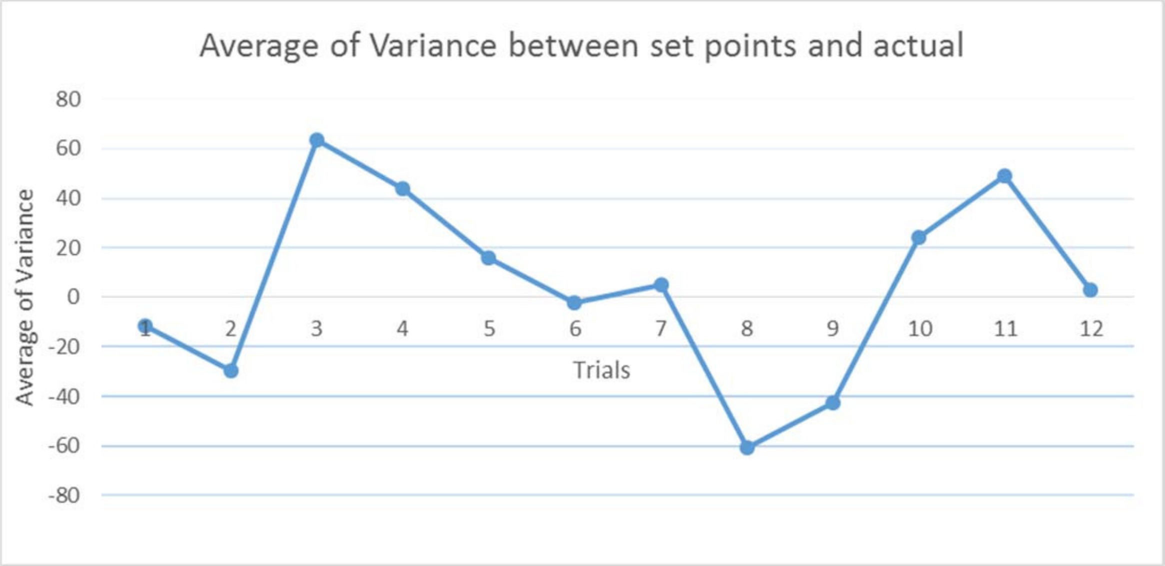


Figure 3.9 Summary of average of variance between set points and actual by trials

3.5 Trial results

The configuration of the trials considers various operational constraints and possible commercial arrangements for electrolyser, and the aim of testing the electrolyser under trials is to study the potential effect that the increasing number of hydrogen refuelling stations will bring. Through analysing the behaviour of the electrolyser under different trials, the trial results will help DNOs with future planning and operating issues that they may face.

In the following analysis trials are divided into three categories depending on the operational scenarios, and are evaluated on the basis of the objectives and constraints involved in each category. Typical trial results are presented and reviewed to illustrate certain behaviours of the electrolyser, and certain control aspects regarding the performance of the electrolyser.

3.5.1 Trials evaluating Network Management objectives

With growing demand and roll out of electrolysers in the near future, it can be expected that network capacity will be exceeded in certain areas. One category of the trials tested the operation of electrolysers in a constrained network. This was to evaluate if they can be operated to avoid triggering network reinforcement. The following trials fall into this category: Trial 1 (Demand Management Network Constraint), Trial 5/12 (Network Constraint Wind/PV), and Trial 6 (Demand Management Network Constraint 2).

Figure 3.10 shows an extract of results for one successful run of Trial 1. During this trial the electrolyser is simulated to be placed in part of an electrical network which is demand constrained. The electrolyser set point is calculated so that the ‘available power’ to the electrolyser is restricted based on local demand. The forecast constraint is an average hourly value, and is used to create a H_2 production schedule to minimise cost, based on the TOU tariff.

At the beginning of the results shown, 05:00, the hydrogen tank is not full and can been seen dropping as two buses refuel. Since the electricity tariff for this period is low, the scheduler triggers the electrolyser to produce hydrogen at maximum rate, using all three units. As local demand increases (local demand includes the demand of the electrolyser), the electrolyser output is restricted to avoid breaching local network limits. Note this is a modelled network limit and not an actual limit on the Kittybrewster network. The yellow curve shows the rate of hydrogen production drops as the electrolyser operation is restricted; however it is still being produced and stored.

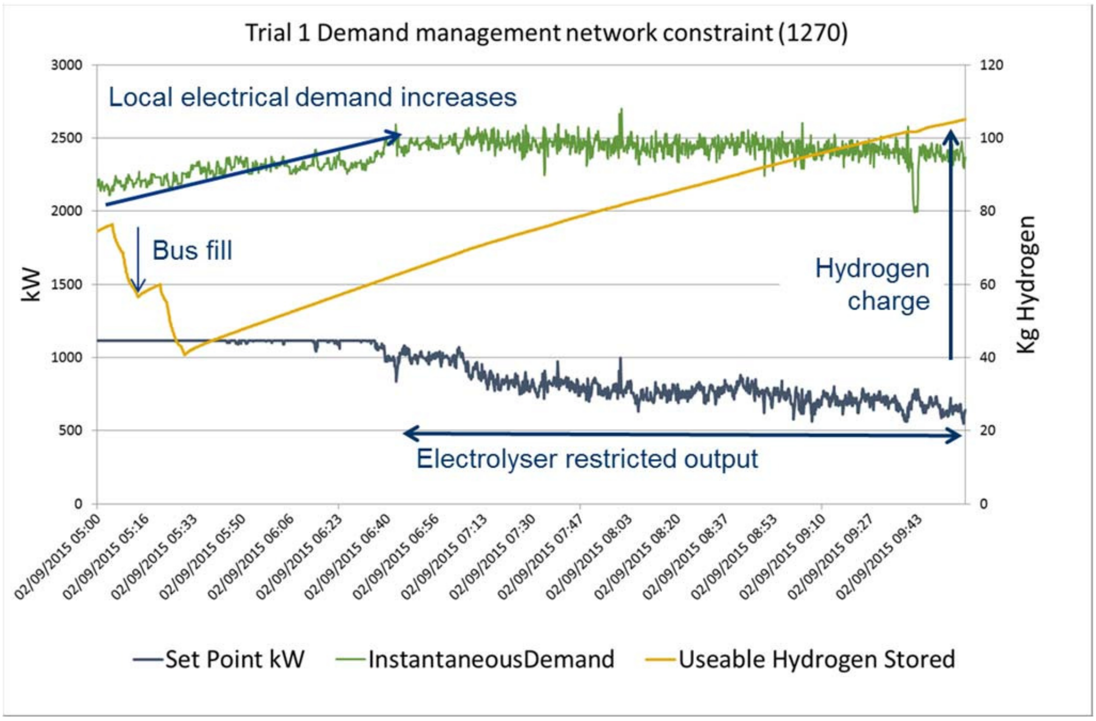


Figure 3.10 Scheduling results for Trial 1 (ID 1270)

3.5.2 Assessing responsiveness and controllability of the electrolyser during the trials

Electrolysers, in addition to generating hydrogen, have the potential to provide support to the electrical power systems sector by modulating their electricity consumption profile [12]. Alkaline electrolysers can change their electricity consumption in the range 15–120% of their nominal power within one second [58]. This feature makes them attractive for coupling with wind turbines. In addition, electrolysers available now in the market have the ability to provide fast response and thus can be used to maintain network frequency within operational limits by altering their consumed power as a function of the network frequency [59], [60], and [61]. A test performed on an alkaline electrolyser with rated power of 40kW shows that alkaline electrolysers can provide a fast response by increasing or decreasing load in just 0.2 seconds following a set-point change. The test results also show that the electrolyser starts to respond to the received set-point in less than 24.3 milliseconds [55].

A number of trials have been conducted to assess the controllability and response of the electrolyser at Kittybrewster. During these trials, the electrolyser was exposed to different scheduled operational and network constraints including the utilization of renewables such as wind and solar PV systems.

3.5.3 Controllability of the electrolyser during the trials

A number of trials have shown that the electrolyser can be controlled effectively through set points even where these follow an erratic profile such as that of a windfarm output. Figure 3.11 shows an example of results of a trial 4 – Maximise net wind. During this trial, power from the wind farm is used to fulfil the local demand, and any excess power from the wind farm (the 'spill') is used to operate the electrolyser. A baseload is in place to avoid cycling of the electrolyser if available power dips below the minimum required to operate. This means that even if there is no 'spill' power available the electrolyser will continue to produce hydrogen at a low rate. It is clear from the figure that the electrolyser is acting as responsive load as it starts consuming the additional power generated by the wind farm.

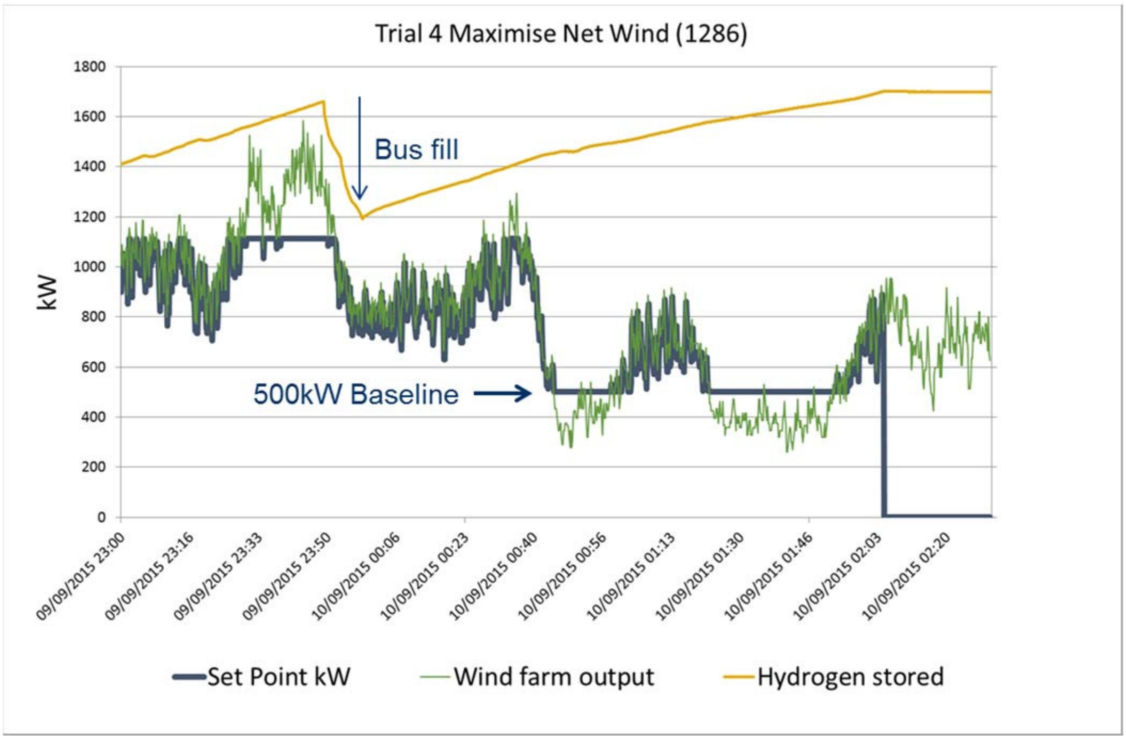


Figure 3.11 Results of Trial 5 network constraint wind (1478)

3.5.4 Additional power consumption

When the hydrogen tank is full, the set-point goes to zero, but the measured power takes time to reach the set-point value. About 400kW is consumed for ten minutes and then reduced to 150kW for another five minutes before following the set-point. This is due to the plant ancillary loads. Moreover, there is a small difference in power between the set-point and the measured power, which is usually in the range of 40-80kW. This can be the active power losses from power converter. An electrolyser's cell stacks typically require DC to split water, thus power electronics is used to convert AC to DC. The power loss of an AC/DC converter is generally assumed to be between 5–10% of the rated power by most of the manufacturers. There are also a few auxiliary independent circuits that support the hydrogen production and storage process which add to the difference in measured power versus set-point.

3.5.5 Responsiveness of the electrolyser during the trials

As the previous results show that the electrolyser load can be successfully controlled, the time taken by the electrolyser to start changing its load following a set-point change is very important factor. Figure 3.12 shows the electrolyser response time to rapid load variations. It is clear that the electrolyser responds to the set-point change within several seconds.

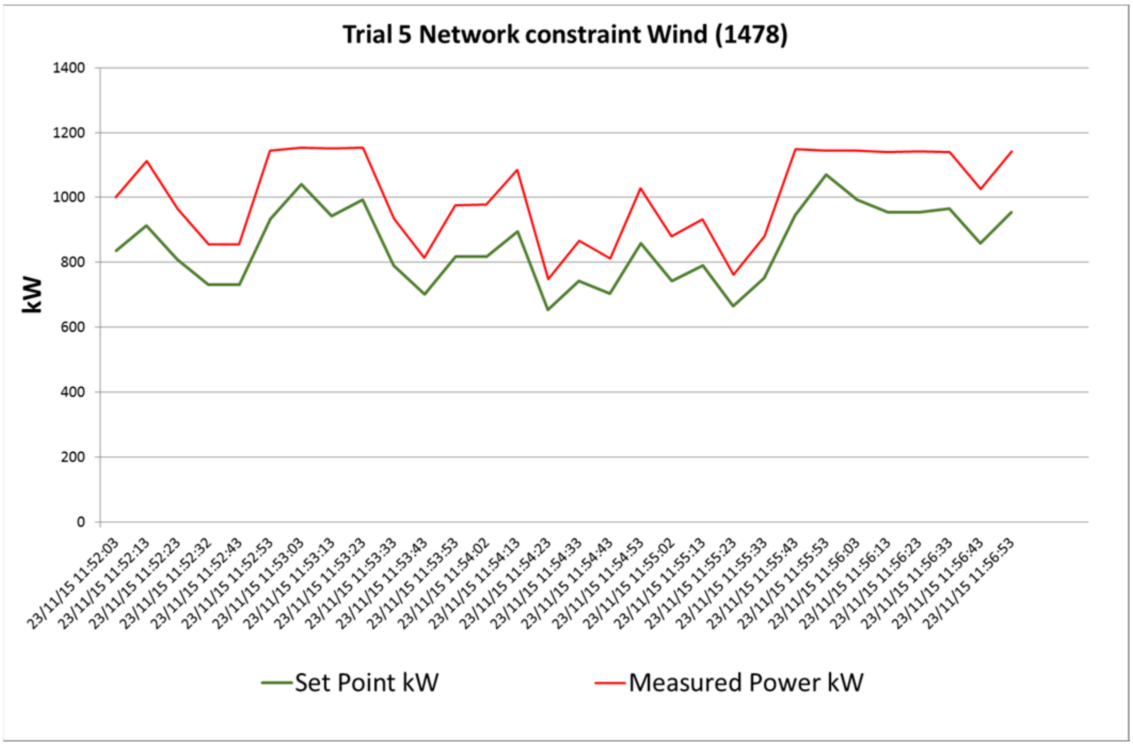


Figure 3.12 Response of the electrolyser to rapid load variations

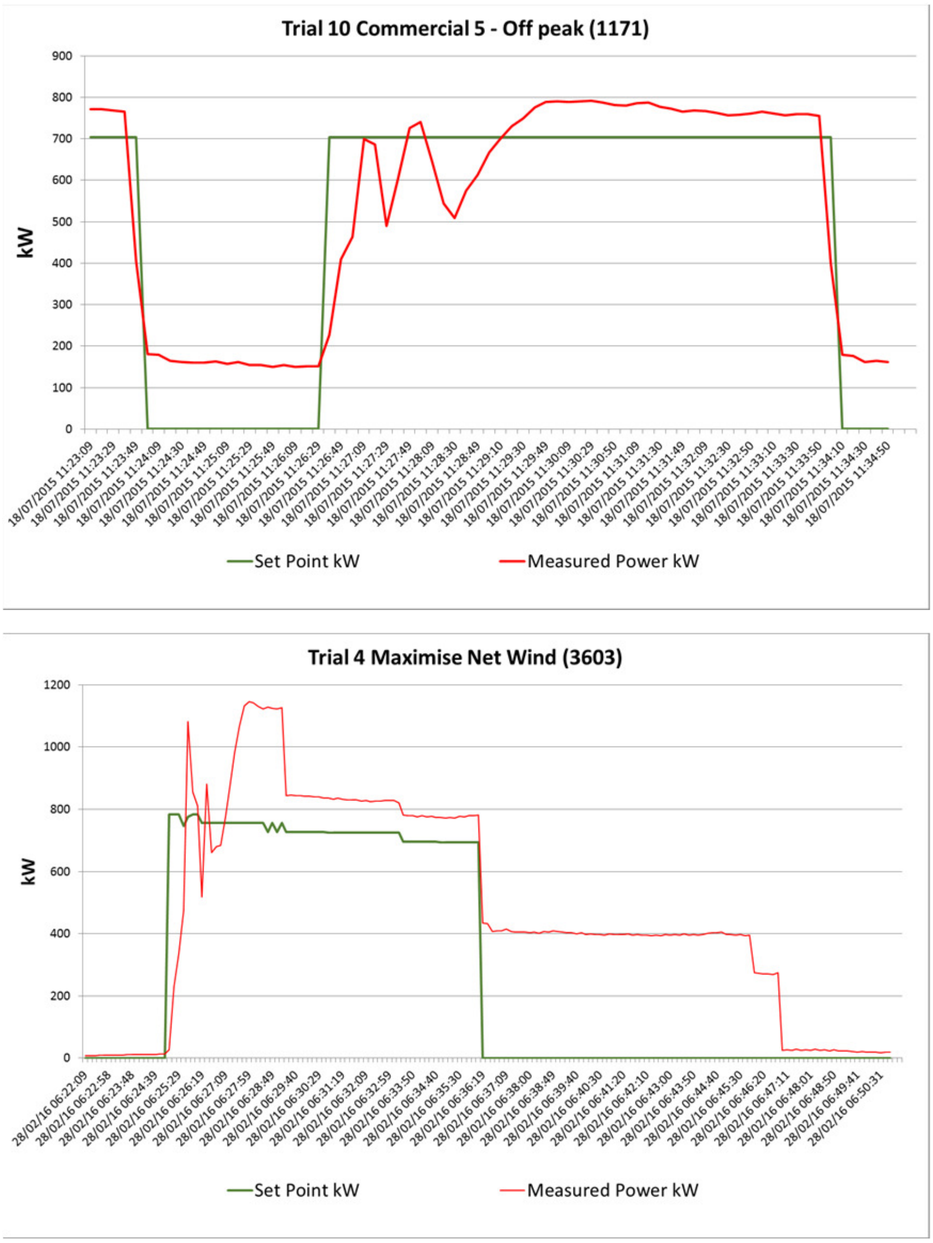


Figure 3.13 Response of the electrolyser to a step change in set-point

Two examples showing the response of the electrolyser to a step response signal can be seen in Figure 3.13. The set-point begins to respond to both an increase and decrease in set-point within the ten second data measurement. Note in Trial 1171 the measured power appears to begin to ramp-down before the set-point is changed; this is due to the ten-second measurement step, and indicates the electrolyser has begun to respond in less than ten seconds. Although the target power is zero, the consumed measured power settled at around 180kW due to the independent auxiliary circuits that support hydrogen production and storage. In Trial 3603 the measured power remains at 400kW for ten minutes after the set-point change, probably due to the operation of the compressors.

Although the ramp-down is leaner, the overall response time is slow in comparison to the 0.2 seconds response time cited from trials of a smaller alkaline electrolyser with a rated power of 40kW [55]. The slow response of some trials can prevent the electrolyser from participation in certain applications such as dynamic frequency response.

Most of the trials show that the electrolyser has a good initial response, and the set-point is achieved quickly. Most of the trials with power variations caused by network limitations and the utilization of renewables have successfully accommodated the power fluctuations. Thus, electrolysers can be a valuable asset in the integration of intermittent generation from renewable sources. To assess the electrolyser response time in greater detail, a measurement step-time of one second or less would be essential, as the electrolyser response time is within this time frame.

The conclusion that can be drawn from the current ten seconds time-step is that the electrolyser has the ability to respond to the predefined set-points within this time. For regulation markets requiring a response time on the order of minutes the electrolyser can respond quickly enough to participate in regulation markets while producing hydrogen – see Figure 3.14 for typical ancillary services requirements.

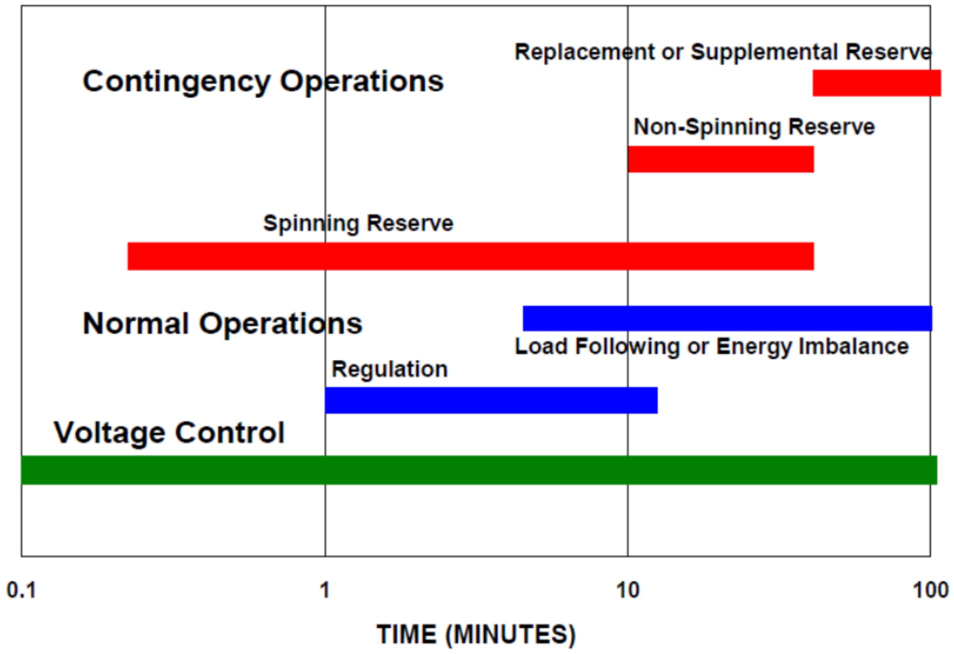


Figure 3.14 Response time and duration of different ancillary services [62].

3.6 Power Quality of the electrolyser during the trials

3.6.1 Voltage

Distribution Electrical Network Operators are required to manage and control the voltage on the electrical network. Voltage is carefully managed by tap changers on transformers at the substations. Therefore any new load or generation added to the network may adversely affect the voltage. In order to ensure that the voltage remain with limits the DNO may need to re design the electricity network. This may involve installing new substations, new lines and cables, or the changing of equipment in existing substations. This can be a costly exercise.

During the course of this project SSEN installed additional monitoring equipment to the network to monitor the effects of the electrolyser on the primary substation.

Figure 3.15 below shows the stepped voltage changes before the installation of the electrolyser and during Trials 1, 3 and 4.

The electrolyser is installed on the 11kV network. An increase in the number of step changes above 1% (0.11kV) would be considered detrimental; it should be noted that the small spike in changes around 0.5% and 0.6% are likely to be due to the operation of the tap changer at the 33/11kV substation to restore the voltage to its target level.

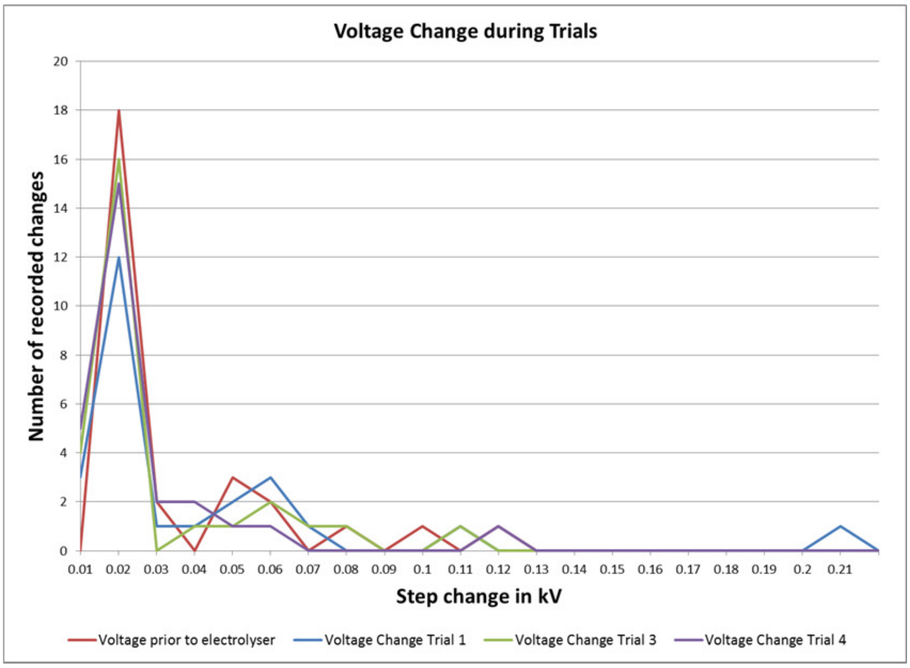
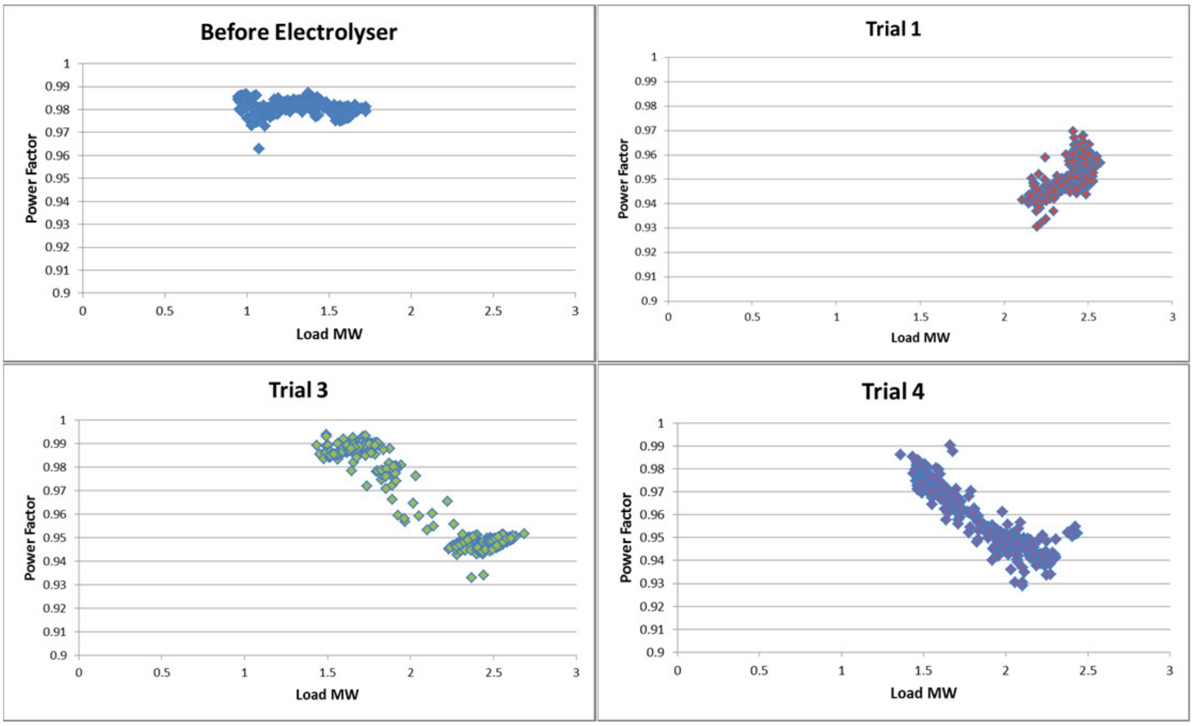


*Figure 3.15: Voltage change and number of changes on the 11kV network (*measured over a three hour period at similar times of day)*

The graph shows that the installation of the electrolyser has not had a detrimental impact on the network during the trials as there has not been any significant increase in the number of voltage changes. In addition there is no significant difference in the profiles between the three selected trials.

3.6.2 Power Factor

The power factor has been plotted against the load at the primary substation prior to the electrolyser and for the above trials in Figure 3.16.



Before Electrolyser

Trial 1

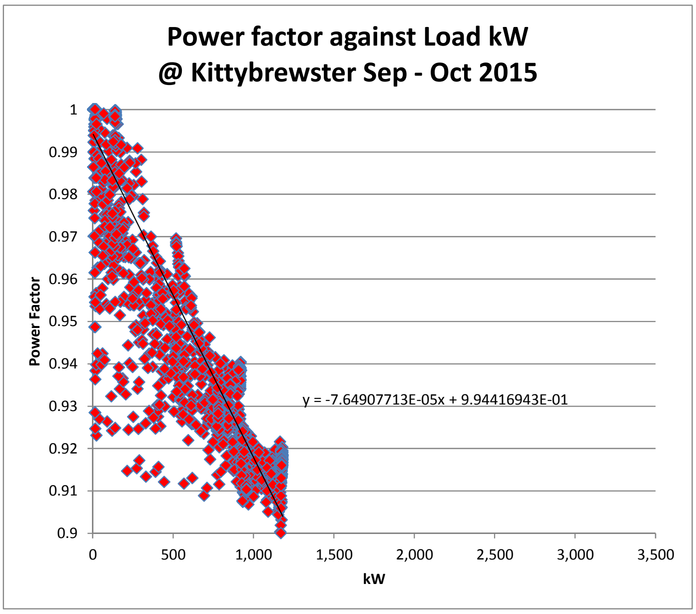
Trial 3

Trial 4

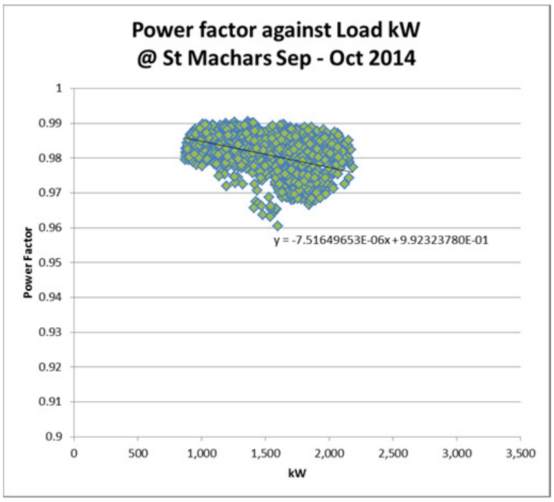
Figure 3.16 Load affecting Power factor measured at the primary substation

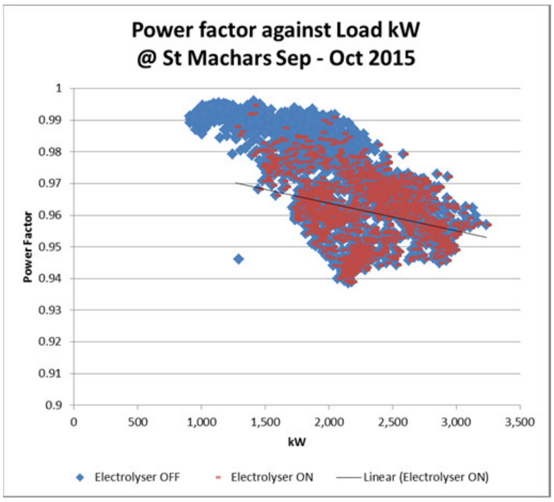
Figure 3.16 shows a clear correlation between load increase and a decrease in power factor. Consumers are penalised for increasing the MVA and reducing the power factor.

Further analysis was undertaken over a longer period to ascertain the impact of the electrolyser on the electrical network. Metering data was obtained from the electrolyser site and the power factor was plotted against the load for the period September to October 2015.



Measurements for the same period were also taken at the primary substation for the previous year prior to its installation.





This confirms that the increased load at the electrolyser site has decreased the power factor on the network and that this has been carried through to the primary substation.

The electrolyser site already has power factor correction equipment with 6 x 100kVAR and 6 x 50kVAR stages built in. Further analysis was undertaken to ascertain the added levels of power correction required in order to maintain a 0.95 power factor at the electrolyser site, which demonstrated that a further 200kVAR would be required.

An increase in reactive power on a network is not necessarily a bad thing and if electrolyser were placed on parts of the network where there was wind generation this reactive power could be used to manage the voltage issues that can be created by wind generators.

3.7 Impact of HRS on the Aberdeen Network

The methodology for evaluating the impact of the HRS roll-out on the network, presented in Section 3.1 of this report, is now used to assess effects on the Aberdeen Network, where the electrolyser is connected for the AHP project. It is estimated there will be 7,317 FCEV cars in Aberdeen Local Authority Area.

To support this number of FCEV, the electrolyser connection requirement is 8.5MVA.

3.7.1 Connection Points

Based on methods described above it is assumed that there will be four HRS connected at Bridge of Don, St Machar, Haudagain and Stoneywood, as illustrated in Figure 3.17, belonging to the Persley Network.

The Persley network has connections of both distributed generation (DG) and a number of loads. Modelling was undertaken for a case with DG at both maximum and at zero output levels.

Results of the network analysis given in Table 8 showed that two transformers would be overloaded in 2029/30, however this overload would be caused by a forecast increase in general demand, and not solely due to HRS connections.

Table 3 summarizes the potential size and location of the assumed four HRS stations.

Table 3 Summary of Hydrogen Refuelling Station Potential Connection Points in Aberdeen

Station	Type	Connection	Substation	Circuit kV
1	4 x Hystat60	2 MVA	Bridge of Don	33/11
2	4 x Hystat60	2 MVA	St Machar	33/11
3	4 x Hystat60	2 MVA	Haudagain	33/11
4	5 x Hystat60	2.5 MVA	Stoneywood	33/11

It can be concluded that Persley Network will not be negatively affected by HRS connections in 2029/30, as only two transformers need to be upgraded, but mainly due to demand increase. Nevertheless, trials carried out also investigated enabling DG connections, and flexible electrolysers demand might help avoid possible renewable curtailments.

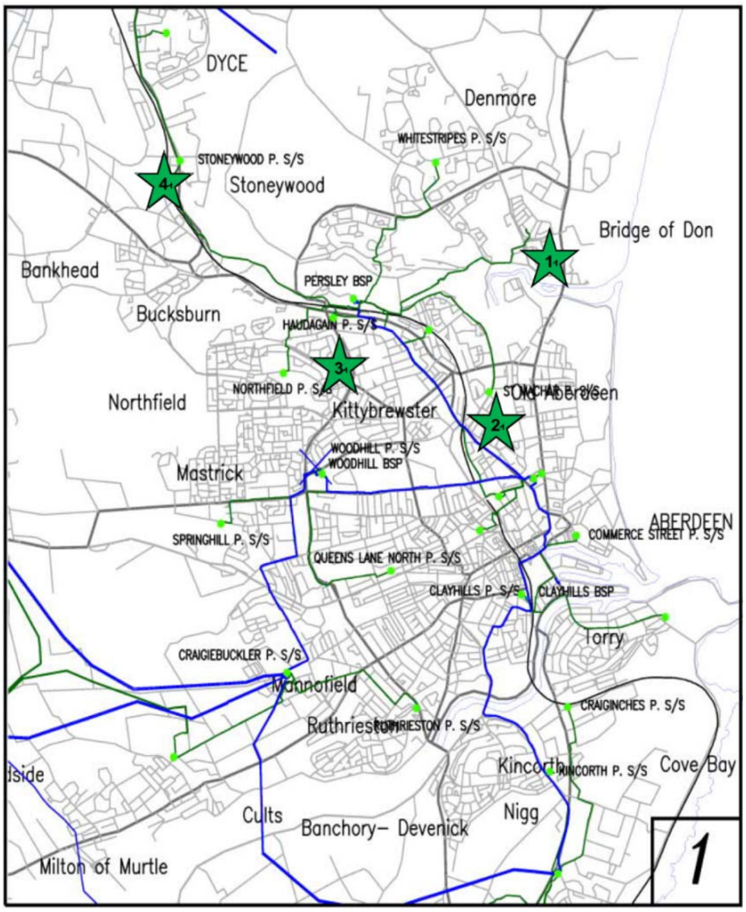


Figure 3.17 Potential Electrolyser Connection Points for Aberdeen City area

Table 4 Case Studies Results for Transformers in 2029/30 Persley Network

Transformers	Base Case		Stoneywood		Bridge of Don		St Machar		Haudagain		Stoneywood +Bridge of Don+ St Machar+Haudagain	
	DG@ max	**DG@ 0**	**DG@ max**	**DG@ 0**	**DG@ max**	**DG@ 0**	**DG@ max**	**DG@ 0**	**DG@ max**	**DG@ 0**	**DG@ max**	**DG@0**
T1	54.2%	54.2%	58.3%	58.3%	54.2%	54.2%	54.2%	54.2%	54.2%	54.2%	54.2%	54.2%
T2	50.2%	50.2%	54.3%	54.3%	50.2%	50.2%	50.2%	50.2%	50.2%	50.2%	50.2%	50.2%
T3	25.0%	33.3%	25.0%	33.3%	29.2%	37.5%	25.0%	33.3%	25.0%	33.3%	25.0%	33.3%
T4	25.0%	33.3%	25.0%	33.3%	29.2%	37.5%	25.0%	33.3%	25.0%	33.3%	25.0%	33.3%
T5	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%
T6	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%	146.8%
T7	41.7%	45.8%	41.7%	45.8%	41.7%	45.8%	45.8%	50.0%	41.7%	45.8%	41.7%	45.8%
T8	41.7%	45.8%	41.7%	45.8%	41.7%	45.8%	45.8%	50.0%	41.7%	45.8%	41.7%	45.8%
T9	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	17.4%	17.4%	17.4%	17.4%
T10	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	17.4%	17.4%	17.4%	17.4%

4. Modelling the Aberdeen hydrogen refuelling station

4.1 Overview

This report looks at the main components of the Aberdeen filling station (storage, electrolyser and compressor) and comprises two main parts. The first looks at the use of the hydrogen system as it is currently configured using basic state equations to investigate the characteristics of on board and on site hydrogen storage charging and discharging. The second part looks at how the operation of the filling station system using modelling and simulation, with an attempt to optimise the size of the filling station against different hydrogen demands and operating strategies.

4.2 Initial characterisation of storage charge/discharge

Spreadsheet models of the hydrogen storage, and bus fuel tank were developed. These made use of the "REFPROP" excel library extension from the US National Institute for Standards and Technology [70], which enables the properties of a gas at any pressure or temperature to be determined from an extensive empirical database. For hydrogen, this is preferable to using an idea gas model, as at high pressures and low temperatures hydrogen ceases to behave as an ideal gas.

4.2.1 Bus fuel tank

The bus fuel tank holds approximately 50kg of hydrogen at 15°C and 350bar [71]; this indicates an on board storage volume of roughly 2m^3. A typical bus fill is around 30kg, so there is a residual 20kg of hydrogen remaining prior to a hydrogen fill.

Figure 4.1 shows the variation and pressure for a 30kg charge, starting from 20kg of residual hydrogen. This assumes that the incoming hydrogen is at 15°C and that the on-board hydrogen is at the same temperature.

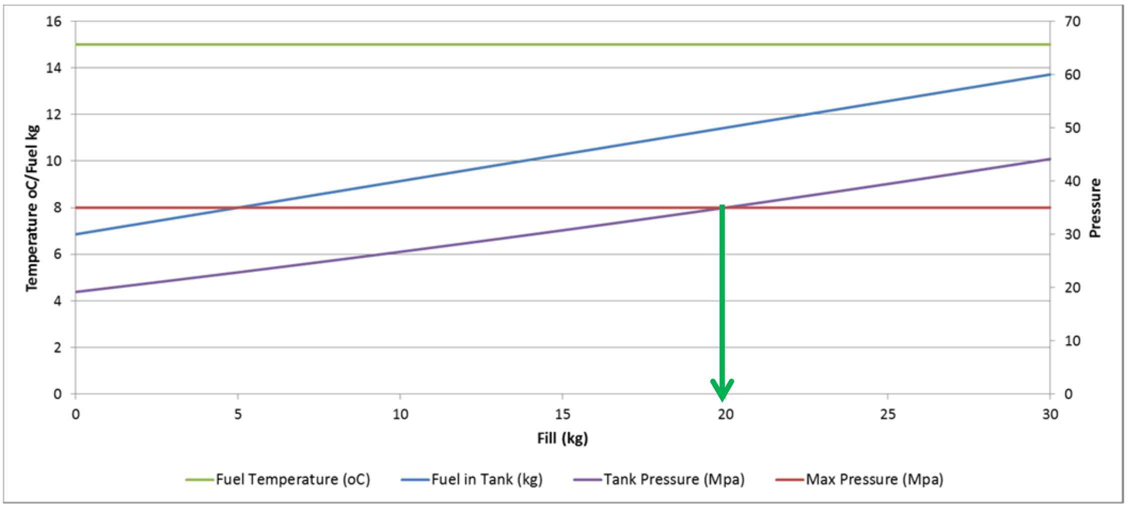


Figure 4.1 Variation in bus fuel tank pressure during an isothermal fill.

The tank pressure at the beginning of the fill is approximately 200bar, rising to 350bar at the end of the fill. Note that if the fuel is pre-cooled, then a greater mass of hydrogen could be stored on board. For example, if the incoming fuel is cooled to -40^{o}C, then an additional 4kg of H_2 could be added before the 350bar limit was reached (Figure 4.2), increasing the range of the bus between fills. The Linde website indicates that the H_2 leaving the IC90 compressor is cooled to -40^{o}C [77]. However, the hydrogen leaving the compressor at the Aberdeen site is only cooled to 10^{o}C [75]. Hydrogen heats as it expands (owing to its negative Joule-Thomson coefficient above 200K), so the temperature in the tank will be higher than 10^{o}C.

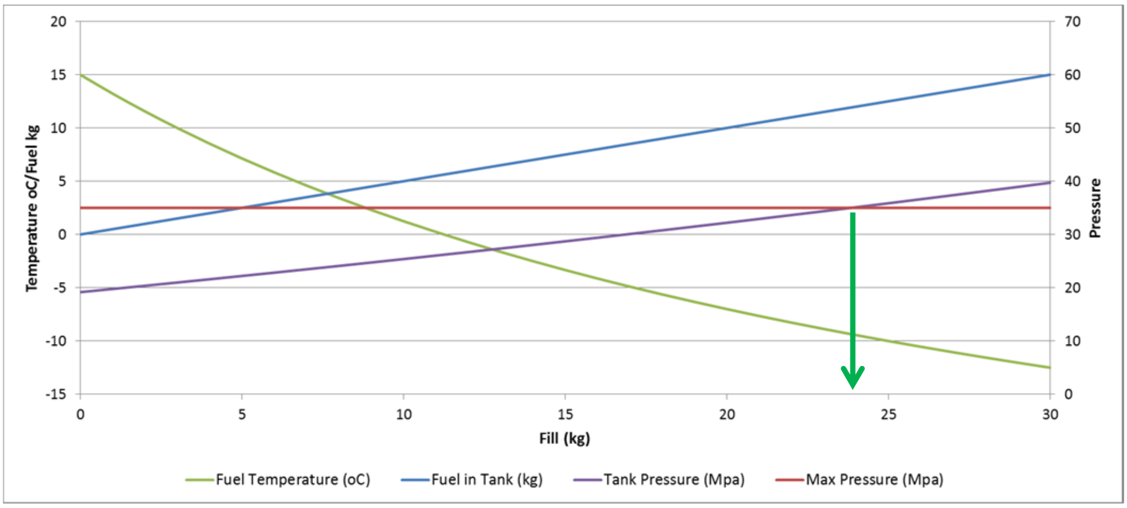


Figure 4.2 Non-isothermal bus tank fill. Initial tank temperature is 15°C and incoming fuel temperature is -40°C.

4.2.2 Storage

The onsite storage comprises 120 cylinders that can hold approximately 400kg of hydrogen at 15°C. The store is divided into three banks all of which are charged to 500bar. As a pressure difference is required to push H_2 into the bus tank, then at least one of the storage banks must at a pressure above 400bar for the bus fuel tank to be fully filled. Figure 4.3 shows the variation in pressure of the storage tank as it discharges.

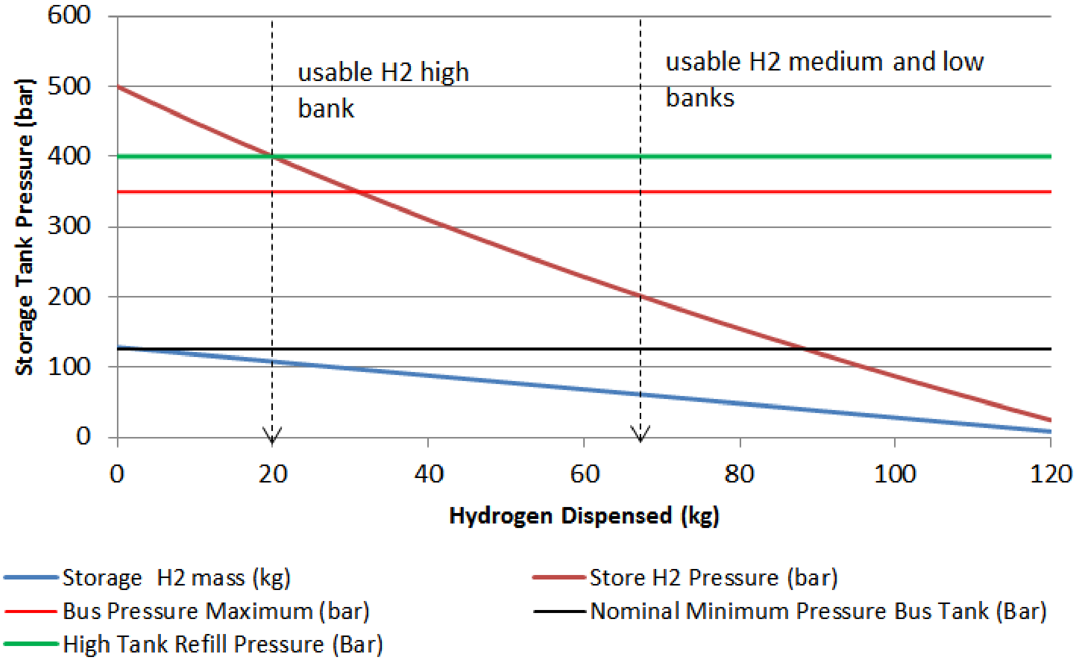


Figure 4.3 Variation in stored H_2 mass and pressure in a single storage bank.

Assuming that the hydrogen is in equilibrium with surroundings (approx. 10°C), then the maximum pressure for the store is approximately 530bar. According to BOC the 'high' storage bank is discharged until it drops to 400bar, while the pressure can drop to 200bar in the other banks. This gives a usable mass of approximately 150kg of hydrogen for the three banks.

4.2.3 Compressor

The Linde IC 90 compressor takes gas at a maximum pressure of 30bar and compresses it to 500bar using multiple piston stages. The maximum stated operating pressure is 1,000bar and the maximum delivered flow rate is 33.6/67.2kg/h for single or double line units. The nominal power consumption is 2.7kWh/kg, corresponding to a power demand of 90/180kW. The hydrogen is cooled to 10^{o}C after compression.

4.2.4 Electrolyser

The filling station features three Hydrogenics Hystat60 alkaline electrolysers, each of which operates at 75°C and 10bar providing a maximum hydrogen flow rate of 5.3kg/h. The power demand at this rate of production is stated as 312kW. Measurements by SSEN indicate that the power consumption including balance of plant is closer to 374kW. Based on the storage analysis, the three electrolysers would need to run at full capacity for approximately nine hours to replenish the onsite storage (150kg).

4.3 Simulation model

A simulation model of the Aberdeen filling station model has been developed using the TRNSYS systems simulation tool. The theoretical basis for both TRNSYS and its hydrogen component models can be found in TRNSYS [80] and Ulleberg [79] respectively. TRNSYS has been used extensively in the modelling of H_2 demonstration projects including the Utsira standalone H_2 system, the Reykjavik filling station and Pacific spirit filling station in Vancouver [78].

TRNSYS is a systems modelling and simulation tool, where a system is described using a connected network of connected components. Each component is essentially a mathematical model that calculates an output state or states based on one or more inputs. TRNSYS solves the resulting coupled set of equations, with boundary conditions (e.g. climate) and control constraints allow the evolving state of the system with time to be determined.

The TRNSYS model of the Aberdeen HRS is shown in Figure 4.4. This includes the key components of the electrolysers, compressor, storage banks, and charge/storage controllers.

The hydrogen draw from the filling station is represented as a time varying demand profile, where the demand is expressed in kg/s.

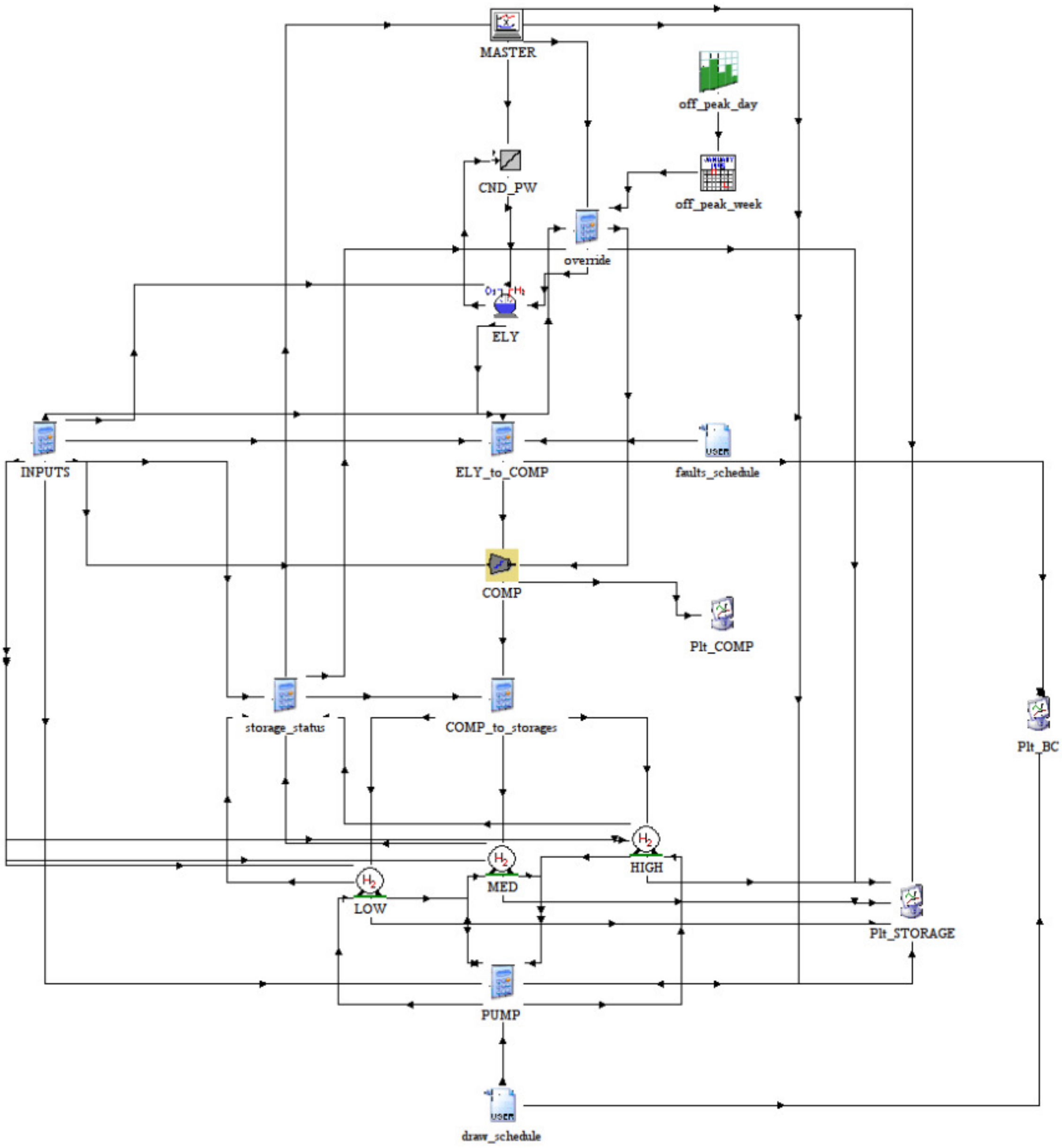


Figure 4.4 TRNSYS model of the AHP station

The main components of the TRNSYS model are as follows:

4.3.1 Master controller

This determines when the electrolysers and the compressor are working, according to the pressure of the compressed storage tanks. Its main parameters are the maximum and the minimum electrical power to the electrolysers, and the storage levels triggering an on or off signal for the electrolysers and compressors.

The maximum power given to the electrolysers when they are producing hydrogen has been taken from monitored data at 374kW per electrolyser; this figure includes the power draws for balance of plant, but not the demand from the compressors. The minimum power provided to the electrolysers when they are in stand-by is 120kW per electrolyser.

The maximum pressure level allowed in the compressed storage tanks has been set at 550bar. The nominal operating pressure is 500bar.

Following a site visit to the filling station and analysis of the monitored data, the minimum pressure level allowed inside the medium and low storage tanks, has been set to 200bar. If the pressure of the stored hydrogen drops below 400bar in the high tank the pressure level inside all of the storage tanks is recovered to 500bar by starting the production of hydrogen in the electrolysers and the compressor.

4.3.2 Electrolysers

Three identical electrolyser models are used. The important model parameters include the area of the electrode; the number of cells; the number of stacks per electrolyser the operating temperature (75°C) and pressure.

The number of stacks and the electrolyser pressure has been taken from the Hydrogenics specifications as four stacks and 10bar. The cell area was estimated as 1.0m^2, while the electrolyser temperature has been assumed constant and equal to 75°C. The maximum hydrogen production rate is 120kg/day.

4.3.3 Compressor

The component used represents a 5-stage poly-tropic compressor. It compresses the hydrogen produced by the three electrolysers from 10bar to 500bar and fills the three compressed storage tanks according to the control law established in storage controller.

4.3.4 Storage controller

This determines the proportions of produced hydrogen filling the three compressed storage tanks. Currently the filling is performed so that the pressure levels inside the different tanks increase at the same rate once the minimum pressure has been reached in the “high” pressure storage bank. This component also measures the maximum pressure level in the three tanks and passes this to the master controller, so that if the storage pressure level in the high bank drop below the 400bar, an automated, unscheduled re-charging fill is triggered.

4.3.5 Storage tanks

There are three compressed storage tank banks on site, all of them at the same nominal pressure of 500bar and each with a storage volume of 4m^3.

4.4 Optimisation studies

A series of optimisations were undertaken with the TRNSYS model, looking at the size of storage and number of electrolysers required to supply different daily volumes of hydrogen, minimising an indicative ten-year cost for the filling station.

A link between the TRNSYS simulation environment and the optimisation tool GENOPT has been included in the model, in order to perform optimisation analysis, particularly in relation to component sizes and capacities. The operation of the tools is shown in Figure 4.5.

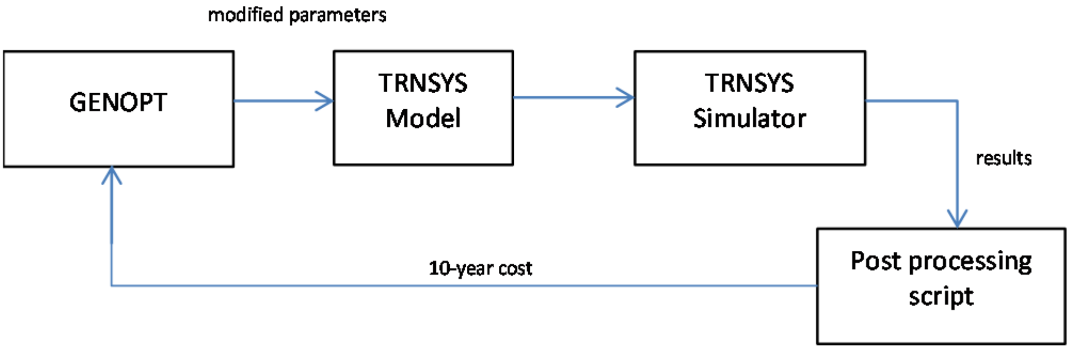


Figure 4.5 Operation of the TRNSYS and GENOPT tool

4.4.1 Cost function

The filling station system was optimised against an indicative ten-year cost, which included the cost for the electrolysers, compressors and storage, along with running costs for the electrolysers and compressors. In this instance optimisation implies sizing the number of electrolysers, compressors and size of storage for minimum running costs against a fixed hydrogen demand profile.

$$C_{10} = aC_E + bC_s + cC_C + 520\left[\int_0^T [e_E(t) + e_C(t)]dt + aPC_F + eC_X\right] \tag{1}$$

C_{10} is the indicative ten-year station cost, which includes capital and running costs; C_E is the electrolyser unit cost and a is the number of electrolysers; C_s is the storage unit cost and b is the storage volume; C_C is the compressor unit cost; and C_X is an automated, unscheduled re-charging fill cost penalty and e is the number of automated, unscheduled re-charging fills, C_v is an unused storage penalty, V is any unused storage volume. Running costs include $e_E(t)$, the electrolyser time-varying electricity price and $e_C(t)$ the compressor time varying electricity price. C_F is a fixed weekly capacity charge, related to the size of the filling station supply – in the simulations, this was taken as the installed capacity of the electrolysers.

The key objective of the optimisation process was to run the filling station normally, without the need for an automated, unscheduled re-charging fill – i.e. where the hydrogen storage tanks need to be filled at unscheduled times when the pressure in the “high” storage bank dropped below 400bar. During an automated, unscheduled re-charging fill, dispensing of hydrogen was stopped. The penalty for an automated, unscheduled re-charging fill occurring during the simulation was therefore set at £1,000,000, consequently any configuration that required an automated, unscheduled re-charging fill has a very high ten-year cost and is highly unlikely to be an optimum solution.

A further cost penalty for unused storage was introduced to prevent the optimisation routine searching through solutions that included significant volume of unused storage.

The costs employed were as follows:

Table 5 Costs used in cost function equation

Electrolyser (£/kW)	700	**Electricity fixed (£/MVA/day)**	96
Compressor (£/kg/24h)	5600	**Automated, unscheduled re-charging fill (£)**	1,000,000
Storage (£/kg)	5475	**Dispenser (£ each)**	42500

Electricity costs reflect Distribution Use of System (DUoS) charges with tariffs as shown in Figure 4.6 along with a fixed capacity charge of £670/MVA/week. This figure is therefore sensitive to the number of installed electrolysers.

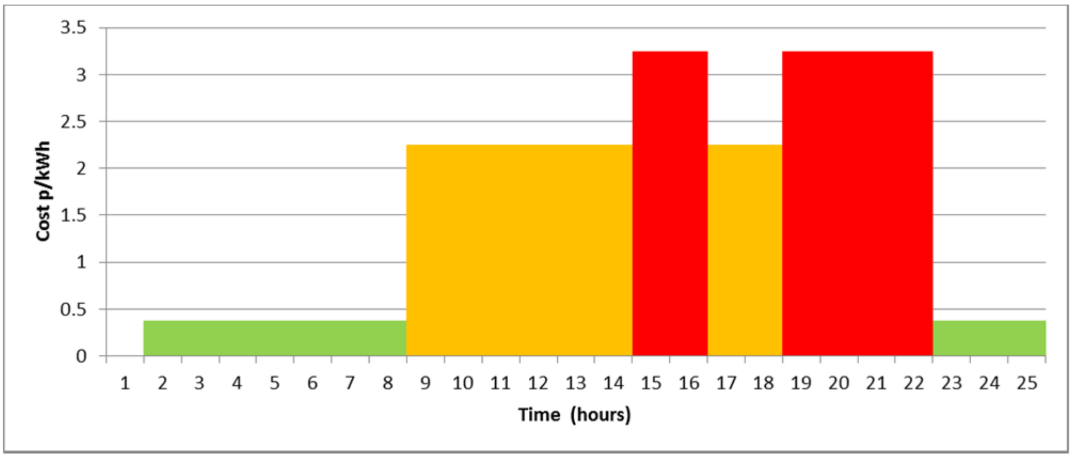


Figure 4.6 Variation in the electricity tariff over the course of a day.

4.4.2 Scenarios

Three filling station operating scenarios were looked at, these are as follows.

- *Unconstrained case* – in this scenario, the electrolysers can operate at any time in order to refill the hydrogen storage and supply vehicles – this scenario acted as a base case.
- *Off peak* – the electrolysers could operate only during off-peak periods: 0000-1300 hrs, 1500-1700 hrs and 2100-2400 hrs.
- *Capacity constrained* – the electrolysers could only operate when extra demand was required in order to absorb surplus wind generation.

The draws and scenarios are summarised in Table 6.

Table 6 Scenarios modelled with TRNSYS

	Daily hydrogen demand (kg)				
Scenario	**288**	**384**	**480**	**576**	**672**
Unconstrained case	X	X	X	X	X
Off peak	X	X	X	X	X
Constrained	X	X	X	X	X

For each case shown in Table 6 the GENOPT tool runs the TRNSYS model multiple times and can vary the number of electrolysers, volume of storage and the number of compressors between runs. GENOPT used a particle swarm optimisation algorithm to identify the parameters for the next run of the model in order to minimise the ten-year cost predicted by equation 1 – which is re-calculated between simulations, using the results from the most recent simulation. The process stops when GENOPT detect that a minimum has been reached. It typically takes 500 weekly simulations to find the minimum value for equation 1.

4.4.3 Demand profiles

For each daily hydrogen demand, a unique draw profile was developed. Unlike the real AHP system, the demand for these cases was assumed to be from private vehicles, rather than buses, with each vehicle drawing approximately 3kg per fill. The range of daily hydrogen demand varied between 288 and 672kg and for each of these fill levels a stochastic hydrogen draw profile was created as shown below as Figure 4.7. The draw profiles show distinct peak periods in the morning and afternoon.

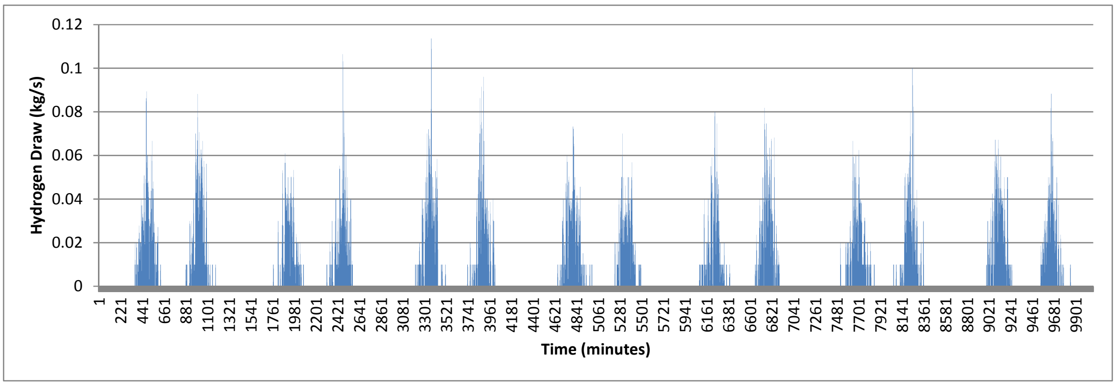


Figure 4.7 One-week hydrogen draw profile for 672kg/week case (1-minute time resolution)

4.4.4 Simulations

In each of the cases analysed, the operation of the filling station was modelled in TRNSYS for a two week period, with the first week of data discarded to eliminate the effects of the model starting parameters (it is assumed that the storage tanks are full at the beginning of the simulation). The second week of data was used in the assessment of the filling station operation and calculation of the costs in equation 1. In addition to the calculation of the cost function, each simulation also produces a power demand profile for the filling station.

Figure 4.8 shows the constrained capacity case. The electrolyser was only permitted to run in the periods highlighted in green, where there was sufficient output from wind above local demand.

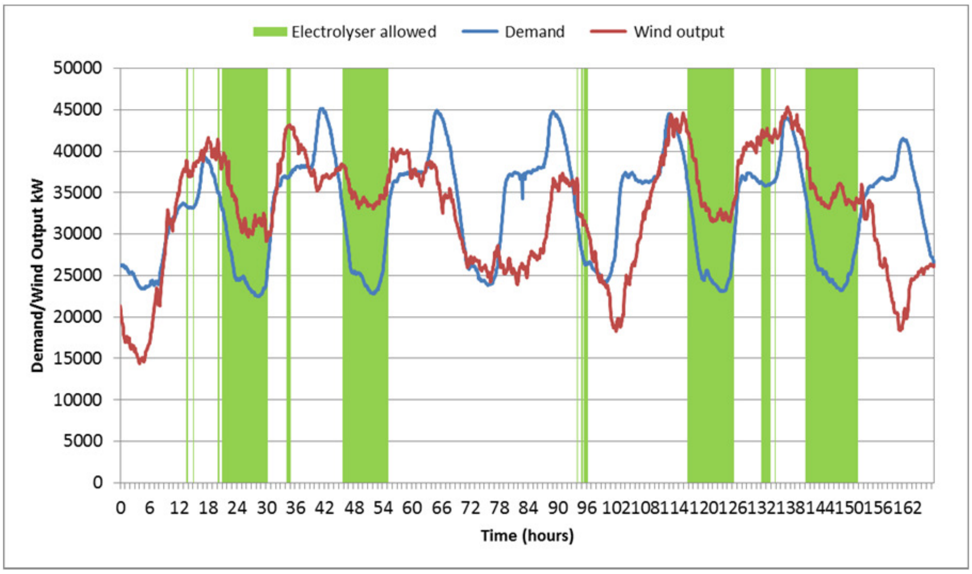


Figure 4.8 Electrolyser operating periods for the constrained capacity case

4.5 Results and discussion

Each simulation of the filling station model gives rise to a power consumption profile such as that shown in Figure 4.9.

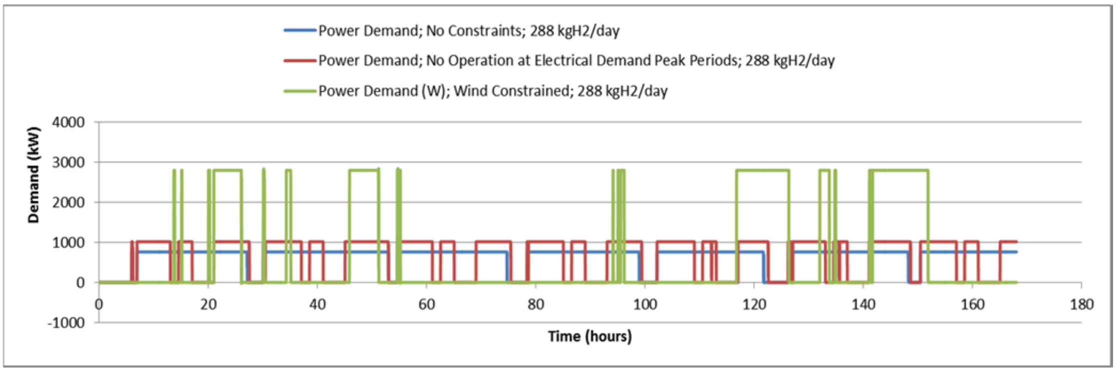


Figure 4.9 One-week demand profiles for different operating strategies and optimum station configurations

Figure 4.9 shows the combined demand for the electrolysers and compressors for the optimised station configuration for each scenario – the optimisation goal being to meet the required hydrogen demand without shutdowns due to low pressure. The results illustrate that, when operating under increasing time constraints, a higher power draw is required (as a greater number of electrolysers are needed to produce hydrogen in a shorter space of time). The results from all scenarios are shown in Tables 7, 8 and 9. Each entry shows the storage volume, number of electrolysers and number of compressors that yield the lowest indicative ten-year cost.

Also shown are the indicative capital and ten-year costs along with the increase in demand and ten-year cost relative to the 288kg H_2 per day case. The figures are derived from the TRNSYS output profiles such as those shown in Figure 4.9 and assumed equipment costs.

Table 7 Results from unconstrained operation simulation

Unconstrained case	**Daily Hydrogen Demand (kg)**				
Daily Hydrogen Demand (kg)	288	384	480	576	672
Volume of Storage (m3)	7.3	7.5	12.3	11.2	13.1
Number of Electrolysers	3	5	5	7	9
Pumps	2	2	3	3	4
Capital Cost £M	5.0	8.2	8.3	11.5	14.8
Indicative ten-year cost £M	83.1	113.8	136.1	163.2	191.5
Increase H2 demand %	0.0	33.3	66.7	100.0	133.3
Increase Indicative Cost %	0	36.9	63.8	96.4	130.5
Capital as % of ten-year cost	6.0	7.2	6.1	7.1	7.7

Table 8 Results from off-peak operation simulations

Off peak case	**Daily Hydrogen Demand (kg)**				
Daily Hydrogen Demand (kg)	288	384	480	576	672
Volume of Storage (m3)	8	9.4	14.6	19.1	21.3
Number of Electrolysers	4	6	6	7	8
Pumps	2	2	3	3	4
Capital Cost £M	6.6	9.8	9.9	11.6	13.3
Indicative ten-year cost £M	84.1	119.4	139.0	171.2	198.1
Increase H2 demand %	0.0	33.3	66.7	100.0	133.3
Increase Indicative Cost %	0	41.9	65.2	103.4	135.4
Capital as % of ten-year cost	7.9	8.2	7.1	6.8	6.7

Table 9 results from constrained simulations

Constrained case	**Daily Hydrogen Demand (kg)**				
Daily Hydrogen Demand (kg)	288	384	480	576	672
Volume of Storage (m3)	67.5	67.8	102.5	122.1	133.8
Number of Electrolysers	8	13	14	17	21
Pumps	2	2	3	3	4
Capital Cost £M	13.8	21.8	23.9	28.9	35.5
Indicative ten-year cost £M	88	143	154	187	231
Increase H2 demand %	0	33.3	66.7	100.0	133.3
Increase Indicative Cost %	0.0	61.8	74.7	112.0	161.7
Capital as % of ten-year cost	15.6	15.3	15.5	15.4	15.4

Analysis indicates that the capital and ten-year indicative costs increase almost linearly with quantity of hydrogen dispensed per day. However, the cost increases at a greater rate for the constrained case.

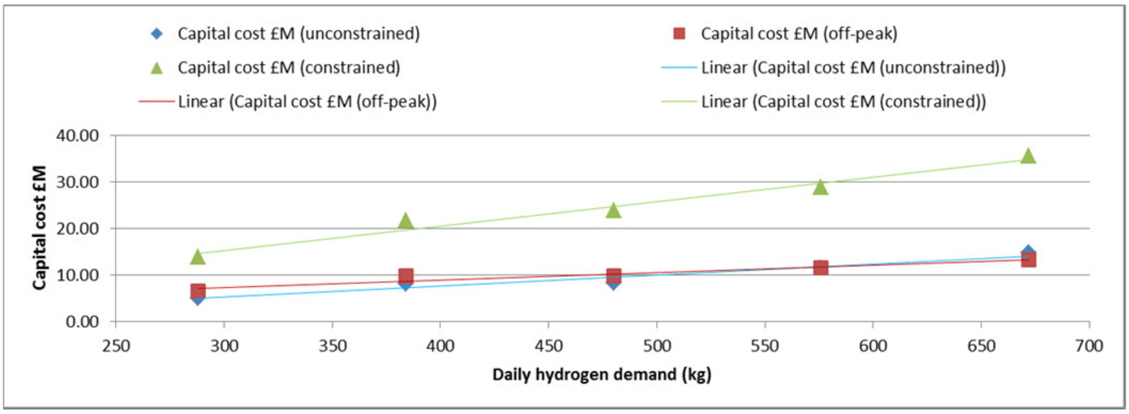


Figure 4.10 Increase in capital cost with mass of hydrogen dispensed

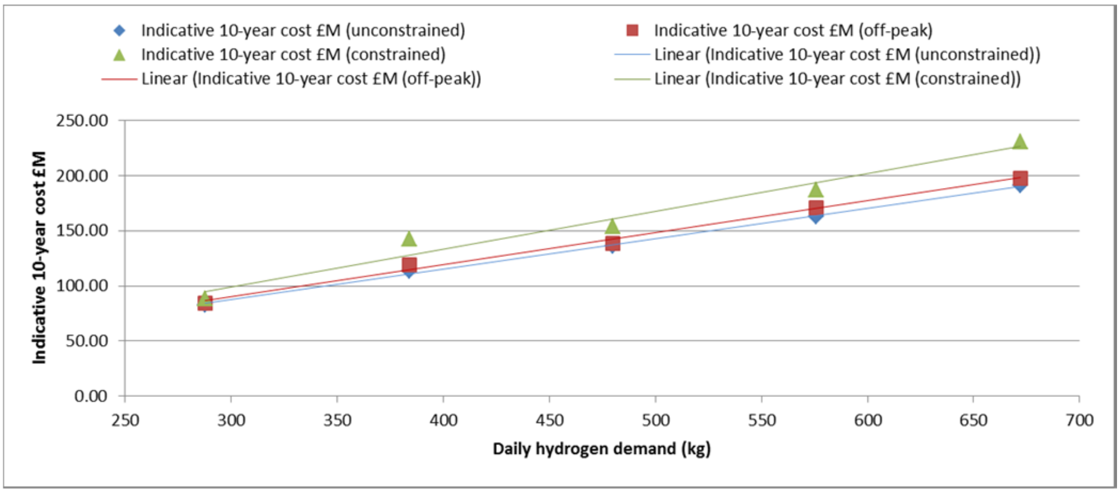


Figure 4.11 Increase in indicative ten-year cost with volume of hydrogen dispensed

A clear trend emerging from the optimization analysis is that attempting to run the filling station, with the operation of the electrolysers restricted, increased the required storage and the required number of electrolysers. The indicative ten-year cost also increases, though not dramatically, as the bulk of the costs over ten years are running costs.

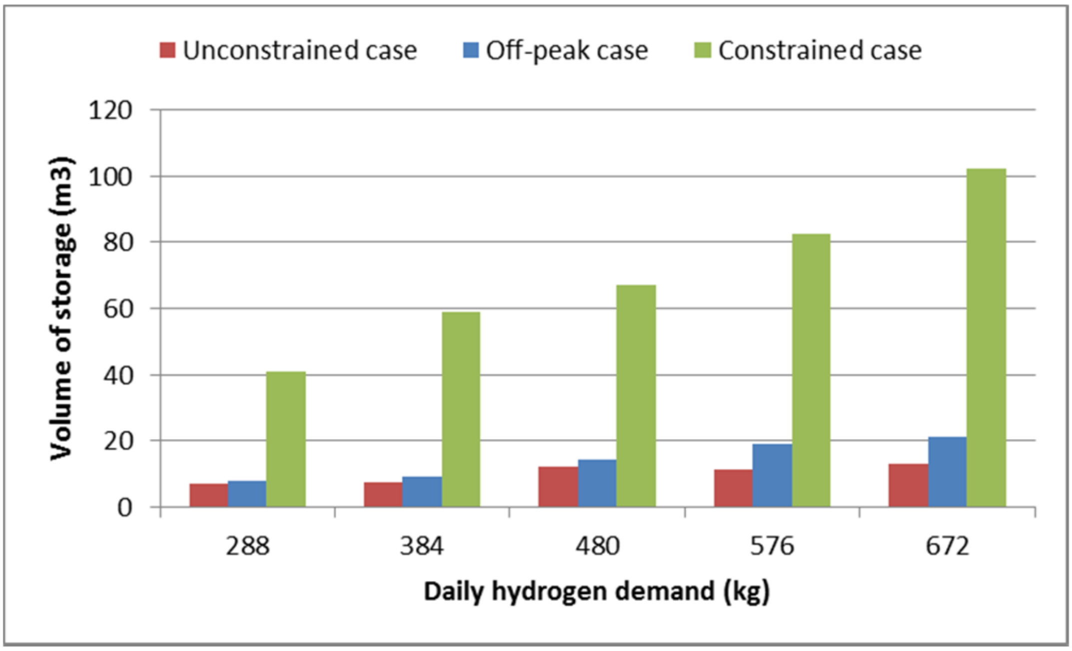


Figure 4.12 The volume of storage required to run the filling station at least indicative ten-year cost and without automated, unscheduled re-charging fills

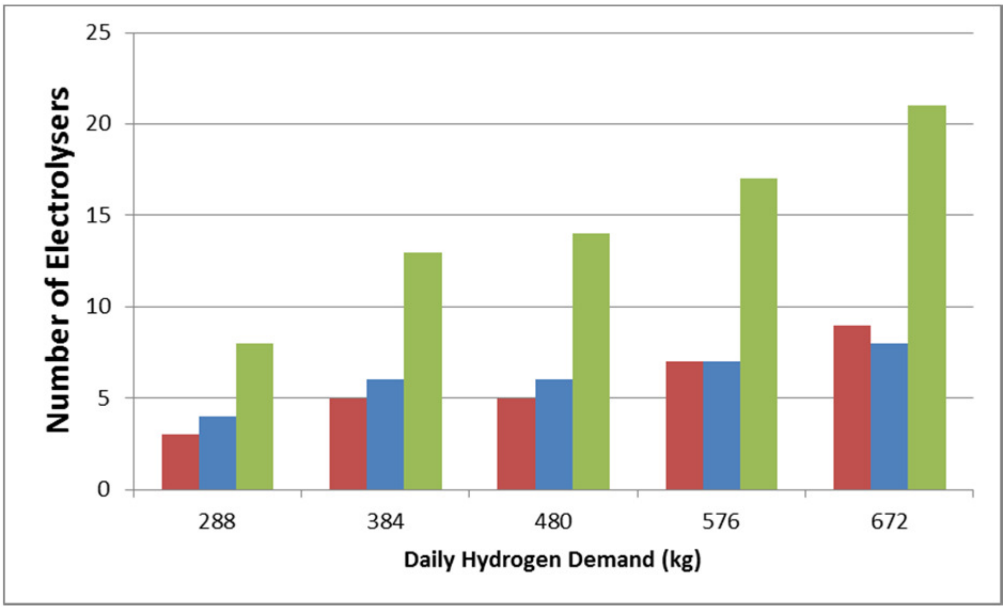


Figure 4.13 The number of electrolysers to run the filling station at least indicative ten-year cost and without automated, unscheduled re-charging fills

The volume of storage required increases compared to the base (unconstrained case) in order to allow the filling station to "ride-through" the periods of time when the electrolysers may be unavailable. Also, the number of electrolysers increases as the storage needs to be charged in a shorter, time constrained period.

Figure 4.14 shows that the ten-year cost increase due to the increased volume of storage and increased number of electrolysers is marginal, as the bulk of costs (~90%) are electricity costs.

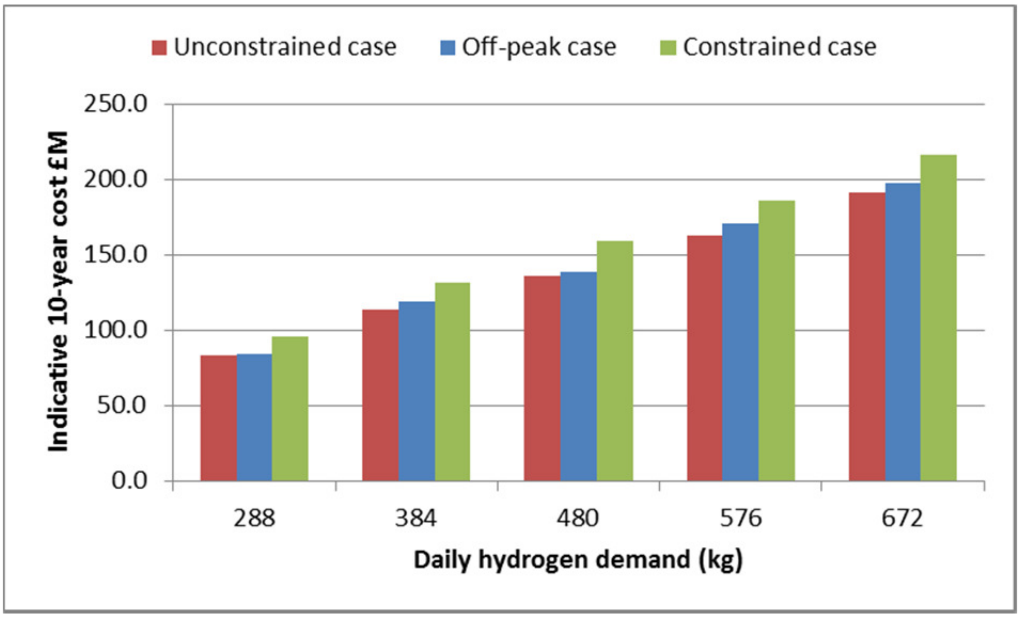


Figure 4.14 indicative ten-year filling station costs

Figure 4.15 shows the capital cost as a percentage of the ten-year cost. As the level of constraint on the operation of the electrolyser increases, so the relative importance of the capital cost increases, due to significantly increased equipment requirements.

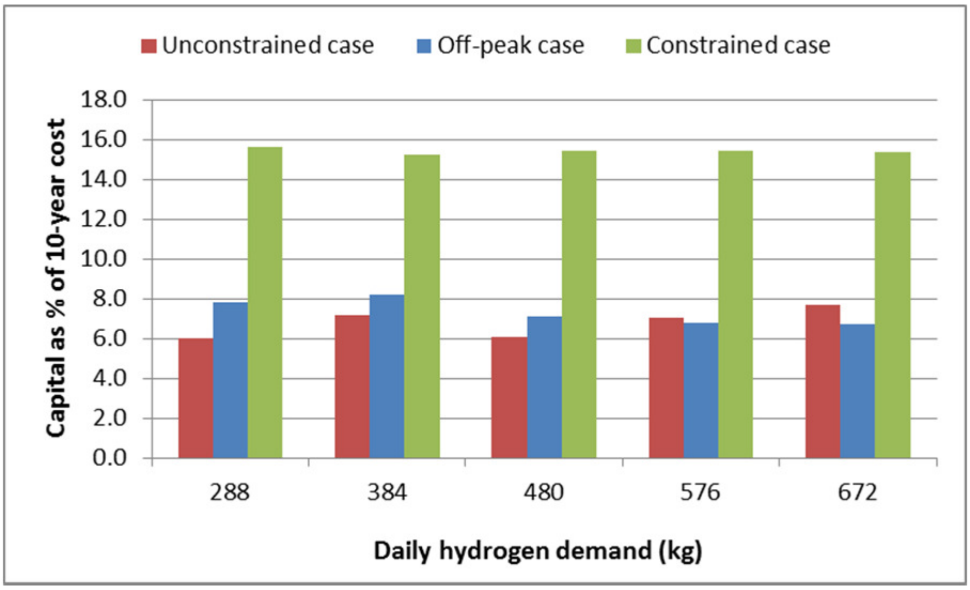


Figure 4.15 Capital cost as a percentage of the indicative ten-year cost

An additional simulation was run, with the electricity unit cost set at the fixed value of 0.335p/kWh (the lowest cost 'green' tariff shown in Figure 4.6). The calculated costs differ significantly, with the capital costs coming to almost 50% of the indicative 10-year costs, which in turn are less than half of the previous simulations as shown in Figure 4.16. As the bulk of the ten-year costs are running costs, the lower electricity price results in a dramatic reduction in this cost.

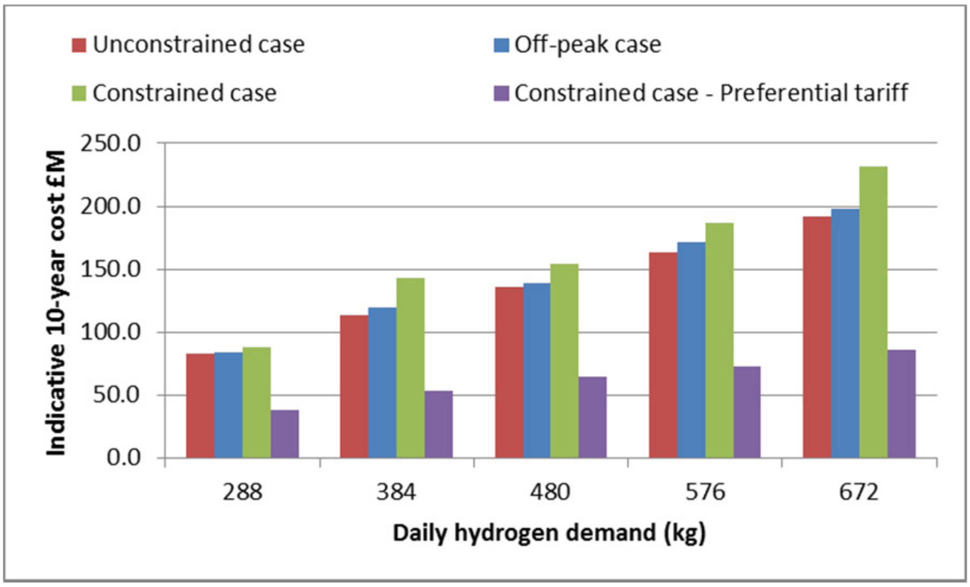


Figure 4.16 Indicative ten-year filling station costs (with lower fixed tariff simulation)

4.6 Overview of simulation model results

4.6.1 Initial Analysis

Analysis of storage and fuel tank charging and discharging has been undertaken using a spread sheet model augmented with NIST REFPROP data.

Chilling of the hydrogen fuel to -40°C can increase the hydrogen loaded into the tank on each fill by around 20%. However, the hydrogen leaving the compressors in the AHP system is only chilled to 10°C.

Data from the spreadsheets has been used to inform the development of a system simulation model of the filling station.

4.6.2 Optimisation Outcomes

A TRNSYS model of the Aberdeen filling station has been developed; this can be adapted to assess performance against a wide range of different system configurations and operating scenarios.

The optimisation process calculated the volume of storage required and number of electrolysers to maintain filling station supplies without the need for automated, unscheduled re-charging filling (i.e. unscheduled operation of the electrolysers and cessation of fuel sales) due to low hydrogen tank pressures. Three operating scenarios were investigated:

(1) Unconstrained operation of the filling station,
(2) Operation constrained to off peak periods, and
(3) Operation to avoid wind farm output curtailment.

The increase in costs is almost linearly proportional to the hydrogen dispensed. The increase is greater for more heavily constrained cases.

In the base case and off-peak charging case, the capital cost was between 6-8% of the indicative ten-year cost; this rose to over 15% for the most heavily constrained case where the electrolysers could only operate to absorb surplus wind power.

A reduction in electricity costs can have a dramatic impact on the indicative ten-year cost.

The clear trend from the optimisation simulations is that as more constraints are placed on the operation of the filling station, the larger the volume and storage and number of electrolysers required.

5. Additional learning provided by the project

5.1 Flexible operation

In the trials undertaken by SSEN, tests were carried out in different environments which looked at possibilities to operate electrolysers flexibly, to defer network reinforcement and for increased penetration of renewable resources. In all cases we have discounted the potential to obtain revenue from Ancillary Services to allow for base case scenarios. Results from the trials indicated that it is possible to achieve the objectives and satisfy constraints set by each of the trials, and that a number of stakeholders including network operators, owners of electrolysers and DG investors could all benefit from these arrangements.

All trials seeking to respect network constraints (generation or demand) had a number of successful instances, which proved that commercial arrangements for this operation are possible in the future.

Also, trials that looked to enable better integration of renewables and reduce their curtailment, succeeded in doing so. Improved forecasting of renewables' availability and hydrogen demand, as well as availability of more hydrogen storage, would significantly improve the benefits to all stakeholders.

The electrolyser has the ability to respond to issued set-points within the ten second time-step used in these trials. As noted from the conducted trials, it is possible for an electrolyser to act as a responsive demand to support transmission and distribution systems, as the required response is in the order of minutes to hours.

The work of this project is a significant step forward in testing the performance of a hydrogen refuelling station in a real world industrial application. It has proven that electrolysers can be used as a flexible load under various conditions including supporting renewables integration and operating in a constrained network. This has the potential to avoid network reinforcement where electrolysers are installed.

5.2 Influence of commercial arrangements on electrolysers sizing and storage

From the optimisation study, it was observed that the volume of storage and electrolyser capacity required to operate the filling station at a range of hydrogen demand levels increased significantly if the filling station operation was subject to network-related time constraints, and interruption to hydrogen availability was to be avoided. Consequently, constraints on operation increase the capital cost of the filling station significantly, though there is a more marginal impact on the longer term indicative costs as the vast bulk of these (over a ten-year period) are the running costs of the station. In the optimisation exercise, which considered only capital and electricity costs, the latter accounted for between 85-94% of indicative ten-year costs, depending upon the operating constraints.

An additional effect of constrained operation was that the peak demand of the filling station was increased due to the greater number of electrolysers needed to produce the required hydrogen in more limited periods of time. This could have undesirable financial consequences. For example, in the case where the station was not operated at peak electrical demand periods, to avoid overloading the network, peak electricity prices could be avoided. However, the greater electrolyser capacity needed to meet the filling station demand could result in increased capacity charges and reduce or negate the benefits accrued from off-peak operation.

6. Conclusion

Several publications cited in this report predict an increase in the number of fuel cell electric vehicles in the UK over the coming decade. A large proportion of the hydrogen to fuel these vehicles is expected to come from electrolysis, produced either centrally or close to the refuelling stations.

The potential benefits of widespread deployment of electrolysers are wide-ranging and include decarbonisation of road transport, reduction in road noise and improvements in local air quality, a reduction in fossil fuel imports, an increase in renewable generation capacity factors, and the stimulation of new employment opportunities.

The operating profile adopted by these electrolysers will depend to a large extent on the network in which they are deployed. Commercial modelling undertaken in this project has shown that operating at baseload can result in a significantly higher ten-year cost when compared with a more flexible mode of operation – even accounting for higher capital cost of storage or electrolyser capacity.

Twelve distinct trials were developed to better understand these operating profiles and the capabilities of the electrolyser. The results of these trials have shown that electrolysers can be operated flexibly but crucially, developers must include enough hydrogen storage to allow for this type of control.

Where they are deployed close to refuelling stations these are likely to be connected in fairly mature urban environments and may therefore contribute to demand constraints at peak hours of demand. This report has shown that electrolysers can be operated to avoid breaching a demand constraint, however appropriate charging mechanisms will be required to incentivise this behaviour, such as Time of Use tariffs, Real-time Pricing, or payments for entering a demand-side-response or active network management scheme. Electrolysers which are deployed close to renewable generation sites can act as flexible demand by increasing the rate of production when available renewable energy exceeds a local generation constraint.

For electrolyser developers seeking connection to the distribution network in future, the outcomes of this project strongly support their capability to operate under a demand or generation constraint to avoid triggering reinforcement on the network. Additionally the outcomes of the trials combined with a review of other research indicates that electrolysers with adequate control systems in place can respond fast enough to provide ancillary services for the network.

With forward planning, incentivisation, and investment in adequate control systems there is potential for the roll-out of hydrogen refuelling stations to become an asset to the network, with capacity to provide balancing services, increase renewable penetration, and crucially for the UK, to decarbonise commercial transport.

Glossary

AHP - Aberdeen Hydrogen Project

ANM - Active Network Management

DNO - Distribution Network Operator

DSM – Demand side management

DG – Distributed generation

FCEV - Fuel Cell Electric Vehicle

HRS - Hydrogen Refuelling Station

LAD - Local Authority District

LCNF - Low Carbon Network Fund

LTDS – Long Term Development Strategy

NIA - Network Innovation Allowance, an Ofgem funding mechanism

NIST - National Institute for Standards and Technology (USA)

NREL - National Renewable Energy Laboratory (USA)

ONS – Office for National Statistics

PEM - Polymer Exchange/Polymer Electrolyte Membrane, a type of electrolyser technology

RTP - Real Time Pricing, a charging calculation method for electricity tariffs

SGS - Smarter Grid Solutions, suppliers of ANM software and systems

SOEC - Solid Oxide Electrolysis Cell, a type of electrolyser technology

SSEN - Scottish and Southern Electricity Networks, the industry partner in the research

ToU - Time of Use, a charging calculation method for electricity tariffs

TRNSYS - a software modelling language used to model networks

UoS - University of Strathclyde, the academic partner in the research

UPS – Uninterruptible power supply

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7. Appendix A: Review of electrolyser technology developments

As mentioned in the introduction to this report, three main types of electrolysers are in use and under development:

Alkaline: the electrolyte and feedstock is a 20-30% solution of caustic potash, with nickel electrodes. A variety of catalysts can be used, including both precious metals (platinum, rhodium or iridium) and cheaper, iron group based alloys. This is the most mature and lowest cost technology, and operates at megawatt scales. However, the technology works only at low current density and pressure, so installations are bulky. The liquid electrolyte has poor dynamic response to changing voltage and operates poorly at low loading. Efficiency is limited because the two gases leak to some extent across the separating membrane and mix, and this is potentially explosive. Safety issues also arise from the corrosive nature of the electrolyte.

Polymer Exchange/Polymer Electrolyte Membrane (PEM): the electrolyte is a solid polymer with attached sulphonic acid groups, which allows H^+ ions (protons) to pass through. This means that it can use pure water or low temperature steam as a feedstock. However, the electrodes in the acid polymer require much heavier protective coatings of precious metals, and the cell body must also be acid-resistant, so PEM technology is more expensive than alkaline [12]. Energy consumption per unit hydrogen produced is similar to alkaline, but as PEM can operate with higher current densities a typical cell is much smaller. Hydrogen of high purity is produced. The solid electrolyte has a fast dynamic response and can operate at low partial loads so PEM is well suited to renewable power-to-gas applications.

Solid Oxide Electrolysis Cell (SOEC): SOEC is the least mature of the three electrolyser technologies, the initial developments dating to the 1980s. The electrolyser is in fact a reversible solid oxide fuel cell which is almost as efficient operating in electrolysis mode. High temperature steam is passed through a ceramic electrolyte - most often yttria stabilized zirconia - between electrodes composed of metal/ceramic mixtures [12]. The technology does show promise for bulk production of hydrogen – with temperatures up to $1000^{o}C$, the process is very efficient, current densities are even higher than with PEM, and precious metal catalysts are not required. Also, CO_2 can be co-electrolysed with steam to produce hydrogen and syngas. However, current ceramic materials become brittle at the operating temperatures so durability is a major handicap.

7.1 Technology developments and commercial availability

Alkaline electrolysers

This is a mature technology, and development interest is centred mainly on higher efficiency, corrosion resistant catalysts and electrocatalysts preferably using lower cost iron group metals. Reported research was mainly carried out in the 2000s, and it is not clear how much has moved into prototyping or commercialisation. The best performing among these developments uses nickel-sulphur-manganese alloy which has good corrosion resistance but low overvoltage, generating less waste heat and relatively high current density and therefore production rate – although this is still less than half the density from using precious metal catalysts [37]. Nickel-molybdenum-copper electrodes have also been highly efficient for hydrogen production in laboratory conditions [38].

A variety of commercial products exists, including large units suitable for power-to-gas production by a utility as well as small-scale, distributed systems suitable for automobile filling stations. European manufacturers include Norsk Hydro [26], IHT [27], AccaGen [28], and Erre Due [29]. As of 2009, large commercial electrolysers had an electricity consumption of 4.1 to 4.8 kWh /m3 gas, and efficiencies of 70-80%.

Methods being trialled to stabilise the nickel in the electrodes include iron coating, and doping with vanadium. Iron and lanthanum additives on the positive electrode increase its porosity and surface area, leading to faster oxygen evolution. Physical methods of increasing the surface area, such as introducing slits or louvres, also help to promote gas separation. Smaller but significant possible methods of increasing efficiency include ionic activator additives to the electrolyser liquid to reduce energy consumption, and decreasing the resistance of gas bubbles to separating from the electrode [39].

A study has been carried out on a potential catalyst for an ambient temperature electrolyser, where no external heating of electrolyser required – this is potentially useful in for stand-alone applications for renewable energy to hydrogen production [40].

PEM electrolysers

This is the main focus for research both in US and Europe, as this is the most promising technology for variable loading, renewable generation integrated applications. Developments are in both catalyst and membrane materials. There are fewer commercial products than with alkaline, and those that are on the market have smaller production capacities and shorter proven operating lives. Manufacturers are US based, including Hydrogenics [30], Giner [31] whose prototype 85bar electrolyser can produce 8kg/ day without compressors; and Proton OnSite [32] whose range includes units capable of running with 1MW wind and producing 1 tonne hydrogen per day. Honda [33] in 2010 opened a solar powered hydrogen filling station that can produce 0.5kg of gas over 8 hours.

An EC funded, collaborative R&D project ‘Water Electrolysis at Elevated Temperatures’ [41] looked for ways of enhancing process efficiency and cost. They looked at steam electrolysis at low pressure as well as pressurised water each with two kinds of acidic (proton) solid membranes. Operational temperatures were between 120-200^{o}C and iridium oxide catalysts were used. Perfluorinated sulphonated (PFSA) membranes worked best but had to be doped with phosphoric acid to maintain conductivity in steam. The programme also included a concept development for pressurised water electrolysis with alkaline polymer (anion) membranes. Development of base metal catalysts for both hydrogen and oxygen evolution reactions was less successful. All variants were tested in a 1kW prototype electrolyser with 5 cells and efficiency over 80% (LHV).

Ongoing work in the US DoE Hydrogen and Fuel Cells Program – a 3-company consortium successfully synthesized and tested of three new iridium based catalysts for OER, that use 3-8 times less precious metal, have higher oxidation resistance and better durability than commercial Iridium black catalyst [42].

Giner are developing a differential pressure PEM electrolyser which produces high-pressure hydrogen in the stack, and oxygen at atmospheric pressure. They have developed a low-cost high-strength membrane with perforated polyimide support impregnated with PFSA ionomer. In testing at NREL this operated at 0.5kg H_2/hour and an efficiency of 74% based on Lower Heating Value [43].

Proton Onsite has fabricated and tested membrane assemblies containing platinum group catalysts at concentrations of 1/25th of commercially available units, which performed at acceptable level for over 900 hrs. Their goal is to automate manufacture to reduce both material and labour costs [44]. They have also scaled-up the synthesis of a lower cost and more stable pyrochlore-based catalyst, and tested a prototype of a solid-electrolyte system where the acidic Proton Exchange Membrane polymer is replaced by an alkaline Anion Exchange Membrane (AEM) so the electrolyser body can be made of lower cost nickel or steel [45].

SOEC electrolysers

Developments in SOEC technology are focused on increasing the durability of the electrolyte and catalyst, and in reducing manufacturing costs. Tests at the European Institute for Energy Research on a commercial fuel cell ceramic showed no apparent degradation after 160 hours of operation. Fuel cells developed at the Danish National Laboratory in Riso have been tested successfully in electrolysis mode. No devices are on the market yet but commercial development is under way at Utah-based Ceramatec [34], who have operated a 4kW SOEC stack for more than 2000 hours; this uses scandia-stabilised zirconia electrolytes which have higher conductivity than the yttria stabilised variety.

Laboratory development of electrolytes that are efficient at lower temperature, and therefore potentially degrade less, has identified cerium oxide, lanthanum gadolinium oxide and composite cerium / zirconium as promising materials. Various electrode materials are also being tested in the laboratory, particularly for the oxygen electrode which degrades faster in fuel cells. Various alternative designs for the cell – tubular, metal supported and microtubular – have been investigated but have not so far proved to be more durable than the standard flat configuration [46].

The EC-funded RELHY programme, completed in 2013, also aimed to develop new or improved low-cost, durable materials but also targeted manufacturing processes and testing at industrial scale. Electrolyte supported cells with lanthanum strontium cobalt ferrite electrodes for oxygen were operated for 400 hours individually and in short stacks with degradation rates between 3-5% per thousand hours. Scaling up to 25 cell stacks did however increase the rate of degradation; nevertheless, this is seen as a promising path to commercialisation [47].

Systems and assemblies

A commercial electrolyser system consists of many individual cells arranged in a stack, together with systems for power conditioning and distribution, cooling, and compression of the gases produced.

The total cost of producing hydrogen is driven by chiefly by electricity costs, but also by capital cost of the plant as well as electrolyser efficiency. A 2009 study in the US estimated benchmark costs of production using state-of the art technology for both alkaline and PEM electrolysers [35]. For large scale (50,000kg/day) central production with wind-generated electricity costing $0.045/kWh, hydrogen cost $3.00 per kilogramme to produce. For distributed production of 1,500kg/day at a filling station using industrial electricity at $0.053/kWh, the cost was $3.32 per kg. Technology developments to the end of 2011 had reduced these estimated costs by 22% and 26% respectively [36]. The current goal of the US Hydrogen Production Subprogram is to reduce it further to $1.00-2.00 per kg by 2020 [36]. SOEC technology is currently at the RD&D stage so dependable cost information is not available.

Hydrogen production methods being developed by a US pump manufacturer [48] include a CO_2 and CO tolerant membrane, improved hardware design with better high-pressure seals and membrane support properties. The design has been tested successfully for several hundred hours.

Ongoing work at the US NREL will test the performance of PEM electrolyser stacks under constant and variable, wind-driven, loading. This incorporates a variable flow product drying technique to reduce the proportion of hydrogen lost in the process when there is low throughput. Also under test is the dynamic response to standard grid operating signals, to enable electrolysers to participate in the grid ancillary services market [49].

Proton Energy Systems have tested a prototype home fuelling concept that can fill a typical commuter car overnight with no mechanical compressor or secondary hydrogen storage. This uses a PEM electrolyser that successfully produced hydrogen at 350bar for several cycles [50]. Giner are also developing a home fuelling electrolyser that will meet the US DOE’s target for $3.90/kg in 2015 [51].

Hydrogen storage

Advances in hydrogen storage are being driven largely by automotive applications in an effort to reduce storage systems weight and increase storage tank ranges. The US DOE is funding research in storage focused on near-term and long-term goals. Near-term research is focused on lightweight, high pressure hydrogen storage using carbon fibre-wrapped plastic liners as storage vessels. Long-term work looks at cryogenic hydrogen storage and storage featuring adsorption or absorption of hydrogen in materials. The current state-of-the-art in compressed hydrogen automotive storage is 700bar storage producing a volumetric density of 0.8kWh/l. The US DOE has a 2020 target of 1.3kWh/l [52].

Progress in adsorption/desorption storage is reviewed by Chen and Zhu [20] who assess the development of a range of storage materials. However, the authors point out that despite the level of research in the area, the kinetics of adsorption or absorption and desorption (i.e. the rate at which hydrogen can be input to and extracted from solid storage) remains challenging. The state-of-the-art volumetric density of 0.4-0.7kWh/l is also below that of compressed hydrogen.

Research is also underway into cryogenically stored hydrogen, however for the automotive sector there are problems with this technology due to the need to insulate the storage tank (and so increase the bulk) and the energy penalty associated with liquefaction of hydrogen (up to 40% of the fuel energy content) [52].

7.2 Technology conclusions

The costs of producing hydrogen from electrolysis are diminishing, for example in the US the cost per kg of hydrogen fell by over 20% between 2009 and 2011. The US DOE target cost for hydrogen produced from electrolysis is \$1 - \$2 per kg by 2020. Current UK diesel prices are around \$1.75/kg, however hydrogen delivers between 2-3 times the range per kg of fuel compared to a diesel vehicle as the higher heating value of hydrogen is approximately 3 times that of diesel.

Alkaline electrolyser technology is the most mature, and many commercial manufacturers exist. However, it is slow to respond to varying electric current, and efficiency falls off at part load. There are safety issues associated with the caustic electrolyte as well as potential for explosive mixing of gases leaking across the separation membrane. Current developments are focused around lower cost, high-surface area coatings for electrodes to promote the formation of gas on the surface; however these developments are still at the laboratory stage and are unlikely to lead to a step-change in performance.

PEM electrolysers are commercially available although in smaller units than alkaline. They are more efficient per volume and can produce high pressure hydrogen without a compressor, so although they require precious metal catalysts, unit costs for hydrogen production appear to be of the same order as alkaline. They are better suited to producing hydrogen from renewable energy as they have good dynamic response. Technology advances are being sponsored by the US DOE who aim to develop their automotive hydrogen economy around PEM. Technology developments are focused on several areas including reducing the loading of high cost materials in the electrodes, specifically platinum and iridium, in order to reduce costs, and finding alternatives to the Du Pont Nafion membrane to improve durability and reduce corrosion on the support structure; currently high cost metals such as titanium need to be employed in the cell stack to resist the acidity of the membrane.

Solid Oxide electrolysers are not available yet commercially. It is a promising future technology, allowing in principle highly efficient hydrogen production at high temperatures with low cost materials. However, the ceramic materials currently under test become brittle very quickly, and although many new materials are being produced and tested in the laboratory none have yet managed to operate within the 1% degradation per 1000 hours that is the standard for SO fuel cells.

Finally, whilst there is considerable ongoing research in electrolyser technologies, the fundamental picture is little changed since 2010. PEM electrolysers offer the promise of more flexible operation, being more suited to part loading and offering higher efficiencies than alkaline electrolysers. However, the problems of the need for high cost materials in the electrodes and durability and degradation remain. Alkaline electrolysers are less efficient (e.g. requiring heating and cooling of the electrolyte), have poorer part load performance and limited loading range, but are still more durable and reliable than PEM. SOEC remain in the laboratory.

8. Appendix B: Contrasting hydrogen and batteries for grid support

8.1 Hydrogen production overview

A hydrogen electrolyser consists of a pair of electrodes immersed in a suitable electrolyte. When an electric current is applied across the electrodes the negative hydroxide ions flow to the positive side and the positive H+ ions (protons) to the negative one. The electrodes are coated with a material that catalyses the production of oxygen at the positive and hydrogen at the negative electrode, and the gases are prevented from mixing and recombining by a separation membrane.

The process uses considerable amounts of energy; however, if the temperature is raised then increasing amounts of that energy can be provided by heat rather than electricity and some of this heat can come from the reaction itself, so the process becomes more efficient. However, an economic production rate for an installation requires higher voltage and therefore generation of more waste heat. So a trade-off has to be made between production rate and efficiency.

Three main types of electrolysers are in use and under development, namely Alkaline, Polymer Exchange, and Solid Oxide Electrolysis Cell. These are described in detail in Appendix A: Review of electrolyser technology developments.

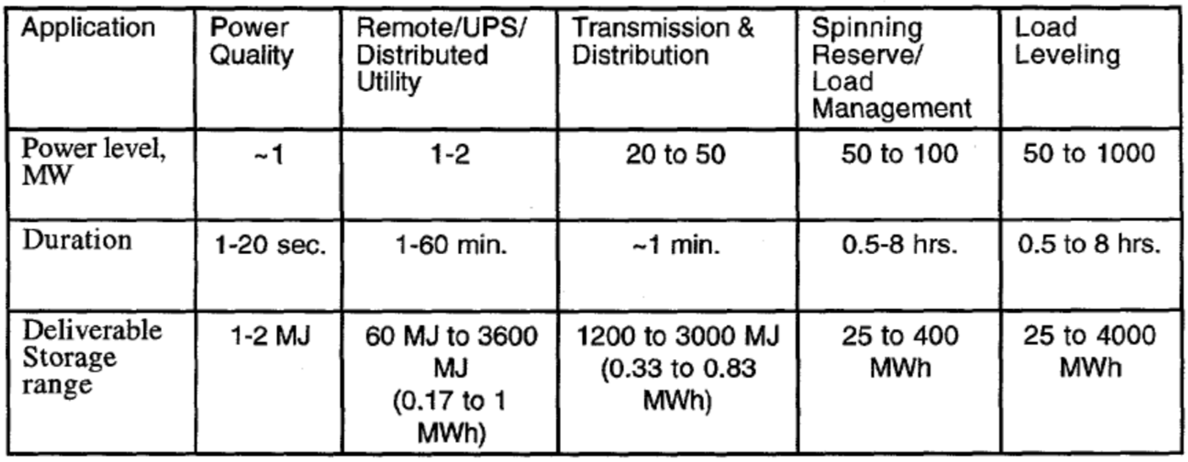
8.2 Grid support capability

In this section, the capabilities of batteries and electrolysers (or hydrogen storage more generally) are compared in their ability to offer grid support at a variety of scales, with a specific focus around the 1MW size, which is relevant to the Kittybrewster hydrogen refuelling station (HRS).

There have been several studies contrasting the capabilities of a range of technologies to offer support services to the electricity network. A selection of these is reviewed in order to put the operation of batteries and hydrogen in the context of a range of technologies.

In an early review for the US Department of Energy, Schoenung [5] summarises the potential range of network services that could be offered by storage technologies, along with the characteristics of the support required in terms of power (W), duration (s) and energy (MJ). These are shown in Table 10.

Table 10 representative energy storage applications and sizes [5]



Application	Power Quality	Remote/UPS/ Distributed Utility	Transmission & Distribution	Spinning Reserve/ Load Management	Load Leveling
Power level, MW	~1	1-2	20 to 50	50 to 100	50 to 1000
Duration	1-20 sec.	1-60 min.	~1 min.	0.5-8 hrs.	0.5 to 8 hrs.
Deliverable Storage range	1-2 MJ	60 MJ to 3600 MJ (0.17 to 1 MWh)	1200 to 3000 MJ (0.33 to 0.83 MWh)	25 to 400 MWh	25 to 4000 MWh

In Table 1, the transmission and distribution entry includes services such as fault damping, voltage control, frequency regulation and deferral of network investment for networks approaching their operating threshold.

The Aberdeen Hydrogen Project's electrolysers have a capacity of approximately 1MW and would be considered as "Distributed Utility" in Schoenung's classification, capable of providing network support (i.e. absorbing or dropping load for between 1-60 mins). However as the electrolysers and storage are distinct, and the storage size can be varied, the duration of a network support action could be longer than the 60 mins indicated by Schoenung. It should also be noted that Schoenung's technology comparison looks at storage from the view of "electricity in minus electricity out", rather than the case with the AHP where load is absorbed or dropped and there is no conversion of hydrogen back to electricity through a fuel cell[1].

Schoenung also reviews the ability of different storage technologies to provide support services for the electricity network; this is shown in Table 11. Note that Schoenung does not assess the use of batteries for load levelling; however there are many contemporary examples of this grid support function such as the 1MW NINES installation on Shetland [6] and the 2.5MW Northern Powergrid installation at Darlington [68].

The Fraunhofer institute is developing a test facility for a 1MW electrolyser (Fraunhofer, 2016) [7] and the group provides a useful summary of a range of energy storage technologies in terms of their range of storage capacity and rated output.

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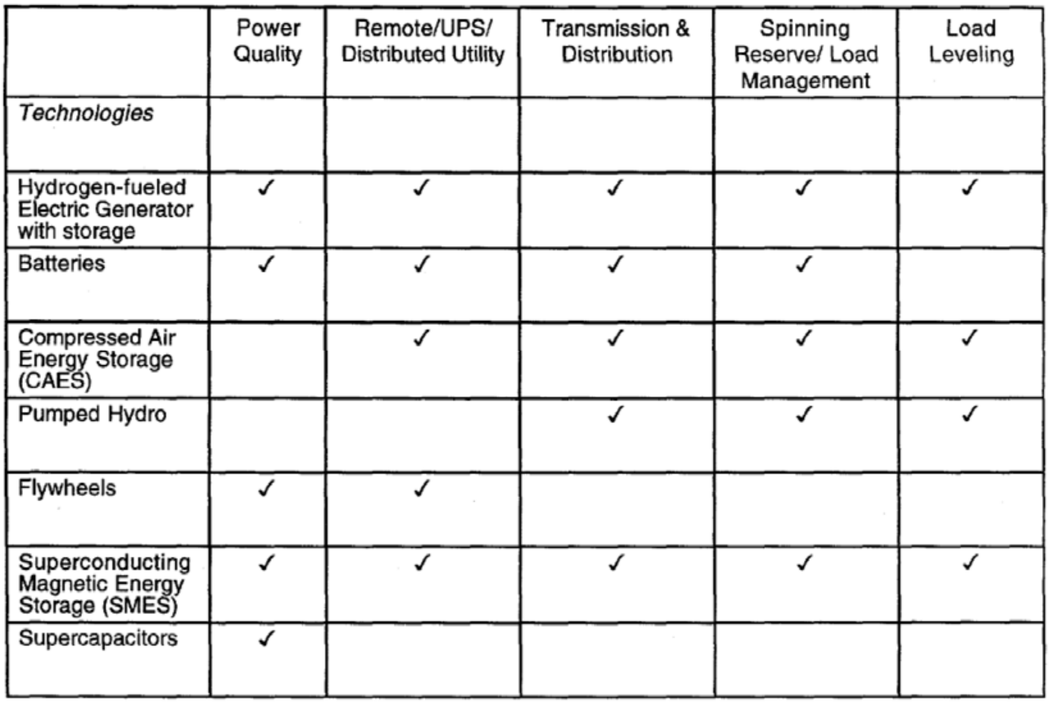
[1] While the AHP uses the H_2 produced to power a fleet of hydrogen fuel-cell buses, it could also be used to generate electricity to feed back into the grid using a fuel cell. While not considered in this project, this method will be investigated by the Orkney Surf 'N' Turf project (see http://www.surfnturf.org.uk/).

Table 11 Technology comparison for utility storage applications [5]



	Power Quality	Remote/UPS/ Distributed Utility	Transmission & Distribution	Spinning Reserve/ Load Management	Load Leveling
Technologies					
Hydrogen-fueled Electric Generator with storage	✓	✓	✓	✓	✓
Batteries	✓	✓	✓	✓	
Compressed Air Energy Storage (CAES)		✓	✓	✓	✓
Pumped Hydro			✓	✓	✓
Flywheels	✓	✓			
Superconducting Magnetic Energy Storage (SMES)	✓	✓	✓	✓	✓
Supercapacitors	✓				

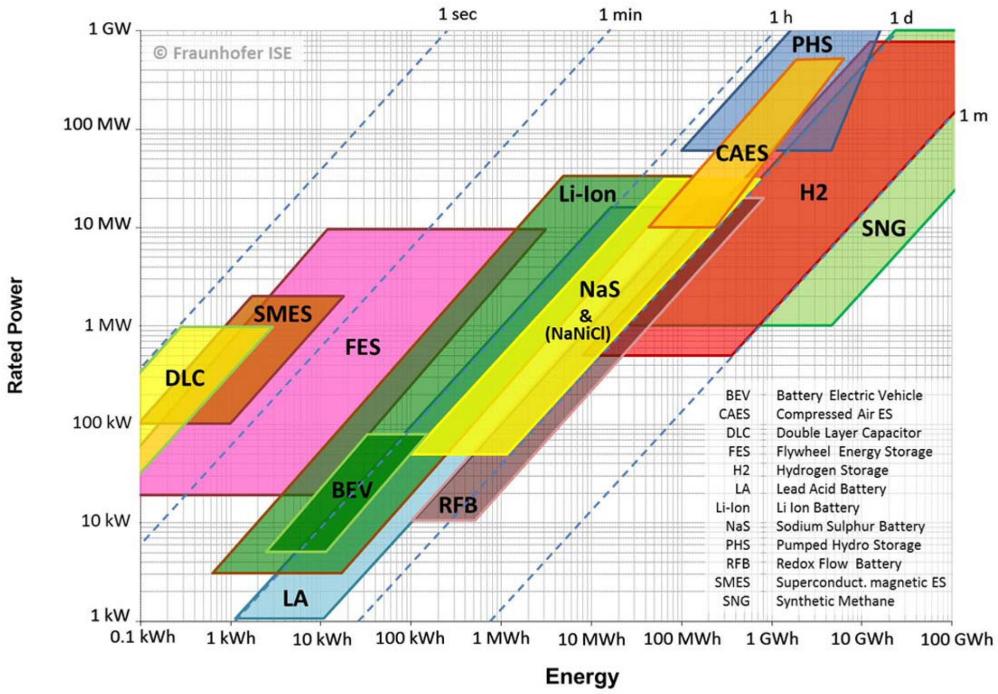


Figure 8.1 Capabilities of different energy storage technologies [7]

Figure 8.1 shows that whilst the capabilities of hydrogen and battery technologies overlap in the 1MW capacity range, there is a considerable difference in their capabilities and ultimately in their potential applications. Battery systems can be used over a wide range of timescales from less than a minute through to several hours and over a wide range of system sizes. Hydrogen systems offer potential where longer time scales and greater quantities of energy need to be stored and where large capacities (hundreds of MW) may be required.

Akhil *et al* [8] map a range of storage technologies to applications, though their study does not encompass hydrogen systems. The range of applications spans power quality support (very small timescales) through to bulk power management over long timescales and very high volumes.

The integration of renewable energy falls within the transmission and distribution support (T&D support, load shifting) shown in Figure 8.2. According to Akhil *et al*, a range of battery technologies are applicable for this role, with capacities of approximately 1MW and operating timescale of a few minutes up to 1 hour.

Finally Chen *et al* [9] reviewed a wide range of energy storage applications and undertook a critical comparison between technologies. Their findings are summarised in Table 12.

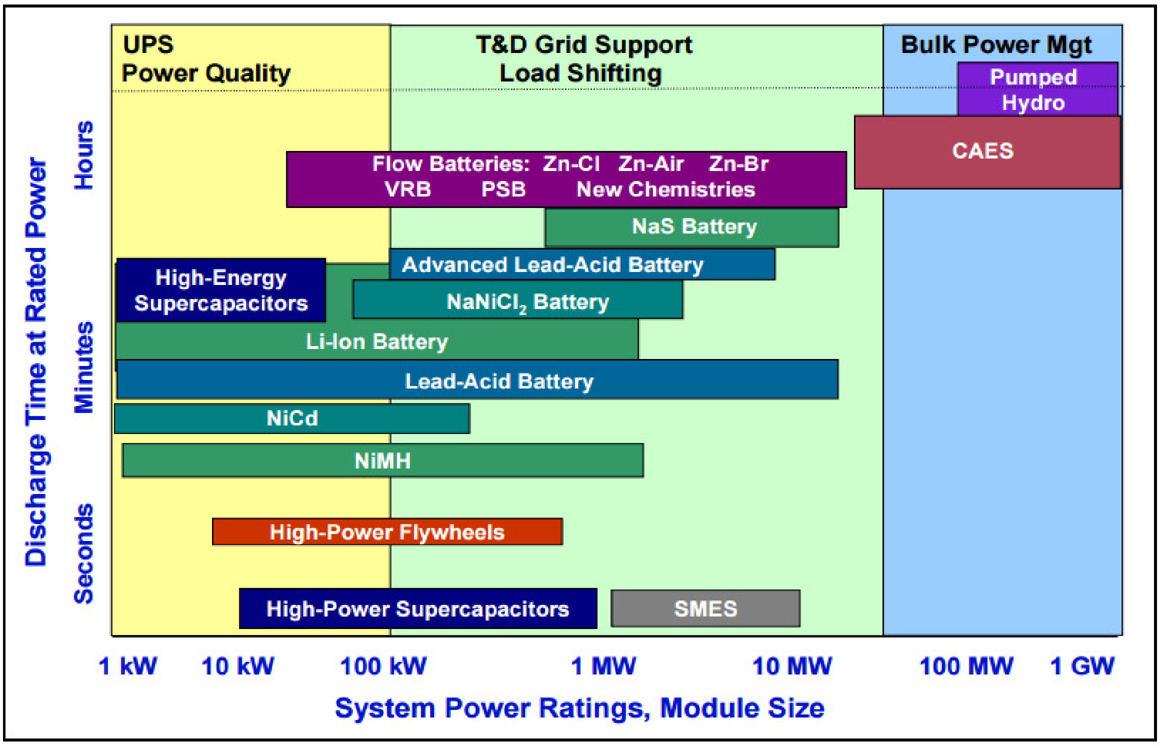
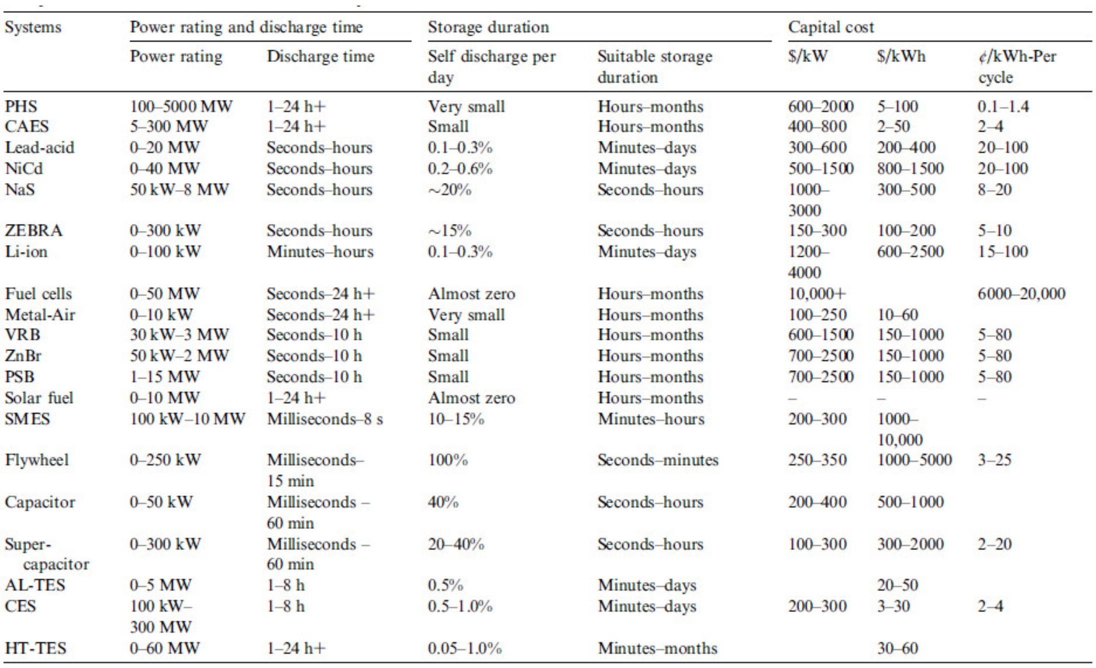


Figure 8.2 Technology mapping of storage technologies to application [8].

Table 12 Comparison of different storage technologies [9]



Systems	Power rating and discharge time		Storage duration		Capital cost		
	Power rating	Discharge time	Self discharge per day	Suitable storage duration	$/kW	$/kWh	¢/kWh-Per cycle
PHS	100–5000 MW	1–24 h+	Very small	Hours–months	600–2000	5–100	0.1–1.4
CAES	5–300 MW	1–24 h+	Small	Hours–months	400–800	2–50	2–4
Lead-acid	0–20 MW	Seconds–hours	0.1–0.3%	Minutes–days	300–600	200–400	20–100
NiCd	0–40 MW	Seconds–hours	0.2–0.6%	Minutes–days	500–1500	800–1500	20–100
NaS	50 kW–8 MW	Seconds–hours	~20%	Seconds–hours	1000–3000	300–500	8–20
ZEBRA	0–300 kW	Seconds–hours	~15%	Seconds–hours	150–300	100–200	5–10
Li-ion	0–100 kW	Minutes–hours	0.1–0.3%	Minutes–days	1200–4000	600–2500	15–100
Fuel cells	0–50 MW	Seconds–24 h+	Almost zero	Hours–months	10,000+		6000–20,000
Metal-Air	0–10 kW	Seconds–24 h+	Very small	Hours–months	100–250	10–60	
VRB	30 kW–3 MW	Seconds–10 h	Small	Hours–months	600–1500	150–1000	5–80
ZnBr	50 kW–2 MW	Seconds–10 h	Small	Hours–months	700–2500	150–1000	5–80
PSB	1–15 MW	Seconds–10 h	Small	Hours–months	700–2500	150–1000	5–80
Solar fuel	0–10 MW	1–24 h+	Almost zero	Hours–months	–	–	–
SMES	100 kW–10 MW	Milliseconds–8 s	10–15%	Minutes–hours	200–300	1000–10,000	
Flywheel	0–250 kW	Milliseconds–15 min	100%	Seconds–minutes	250–350	1000–5000	3–25
Capacitor	0–50 kW	Milliseconds – 60 min	40%	Seconds–hours	200–400	500–1000	
Super-capacitor	0–300 kW	Milliseconds – 60 min	20–40%	Seconds–hours	100–300	300–2000	2–20
AL-TES	0–5 MW	1–8 h	0.5%	Minutes–days		20–50	
CES	100 kW–300 MW	1–8 h	0.5–1.0%	Minutes–days	200–300	3–30	2–4
HT-TES	0–60 MW	1–24 h+	0.05–1.0%	Minutes–months		30–60	

It is worth noting that none of the energy storage reviews consider the production of hydrogen as a transport fuel from surplus electricity as a form of storage; all look at the production of hydrogen with a view to converting back to electricity in a fuel cell at a later date. In this respect, large scale batteries and hydrogen electrolyser and storage systems are not directly comparable. However the use of hydrogen as an energy vector has the potential to provide the same network benefits and ancillary services while also decarbonising the transport sector, which is a key aim in the Carbon Plan.

8.3 Key characteristics comparison

Some of the key characteristics of large scale (1MW) battery and hydrogen systems emerging from energy storage reviews are contrasted below. It is worth noting that 1MW battery and hydrogen storage systems are not directly comparable in terms of function [11]. Table 13 summarises their key engineering and financial characteristics.

Table 13 Key battery and hydrogen characteristics compared

	Li-ion Battery	**Hydrogen (alkaline electrolyser)**	**Hydrogen (PEM electrolyser)**
Energy density	200Wh/kg	40,000Wh/kg (700bar)	40,000kWh/kg (700bar)
Efficiency	~100%	59-70%	65-82%
Lifespan	10,000 cycles	100,000 hours	10,000 hours
Scale currently in operation	32MW up to 400MW	1,000kg H_2/day/stack	500kg H_2/day/stack
Timescale	minutes-days	hours - months	hours - months
Self-discharge	<0.3%	small	small
Response time	50ms	200ms	200ms
Costs (not including fuel cell costs) [12]	\$450-\$600/kWh	\$1000/kW electrolysis plus \$20/kWh H_2 storage	\$1000/kW electrolysis plus \$20/kWh H_2 storage

9. Appendix C: Review of NREL testing

This report gives an overview of the recent research carried out by NREL [14] which evaluated additional technical details that can help understand integration of hydrogen electrolysers in the network.

A number of projects and reports looked into provision of specific services in electricity markets worldwide. While these markets may have different structures compared to the GB market, general results and analysis are still valuable. For example, estimates for the price range, response speed, duration, and cycle time are presented in a 2006 report by Kirby [62], Denholm, et al. [53]. Also, the ability of electrolysers to respond quickly and for a sufficiently long time will define which services electrolysers can provide. In 2011, Hydrogenics Corporation carried out an experiment which successfully demonstrated the ability of their electrolyser to follow a power regulation signal and provide frequency regulation [63]. Thus, with increasing levels of renewable penetration onto the GB system, additional operating flexibility in the system is the key. An earlier NREL Wind-to-Hydrogen (Wind2H2) project integrated wind and solar generation with two electrolysers to generate hydrogen for use in hydrogen vehicles. The findings presented in [64] showed that electrolysers can be responsive in support of renewables and also explored novel configurations to increase system efficiency when connecting these renewable resources. Results of tests discussed in [55] were also part of the Wind2H2 project, with the initial results presented in [65].

9.1 Background for the investigation

Electrolysers provide hydrogen which can be used for different purposes such as industrial processes, power generation transportation and injection into the natural gas pipeline. Often, hydrogen is stored in tanks for later use, which means that with good planning it can act as a flexible load. With an increased penetration of renewable generation there is an increased need for such flexibility that can be provided by loads. Yet, despite a significant number of electrolyser projects installed around the world, there has been insufficient data regarding their practical technical performances, which is a key to understand how this technology can provide flexibility services and how both system operators and electrolyser owners can benefit from such provisions.

9.2 Overview of services investigated by NREL Report

To explore the operational flexibility of electrolysers, NREL carried out experimental testing to evaluate the potential for electrolysers to provide additional support to renewables or network operation. This experimental research was performed on a proton exchange membrane (PEM) and an alkaline electrolyser [14] in 2014. The main objective of that NREL report was to evaluate the services that the electrolyser could possibly participate in. These services include integration of renewables, end-user energy support, transmission and distribution (T&D) system support, and wholesale electricity market services.

End-user energy management

This service looks into ways of operating electrolysers to allow the end-user to benefit from demand shifting and pricing schemes that reward customers that help reduce the system peak demand or increase/decrease consumptions when suitable. These pricing schemes include Time of Use (ToU) tariffs and Real-Time Pricing (RTP). In the case of electrolyser, it is important that it ensures utilisation of produced hydrogen and also has adequate storage which will allow it supply customers when needed (and which can be at different times from hydrogen production).

Transmission and Distribution (T&D) system support

In some instances, generation and/or demand can substitute each other, and this has been recognised by most regulators, with demand side management and efficiency seen as complementary to distribution and/or transmission infrastructure.

Wholesale electricity market services

In order to maintain system balance and reliability, system operators need to procure various ancillary services, including load-following, voltage regulation, spinning reserve, non-spinning reserve, etc. The value of energy and ancillary services can provide significant additional revenue streams to the electrolyser, and thus it is worthwhile for its owner to evaluate operational strategies (e.g. operating at 80% capacity) to participate in ancillary services markets.

9.3 Testing aims and arrangements

The ability of electrolyser units to be implemented in power system operation depends on a number of factors. Those considered important and tested by NREL include:

- ***Initial Response time*** - the time that an electrolyser takes to start load changing following a set-point change
- ***Ramp rate*** – the speed at which electrolyser can change its consumption
- ***Energy capacity*** - the level of hydrogen that can be stored for use in meeting the hydrogen demand. Under baseload operation the energy capacity is less important because the hydrogen production is predictable; however, with new operating schemes the energy capacity must be considered in greater detail.
- ***Power capacity*** - the total rated power for the device. The size ranges from kilowatts to megawatts and is important for establishing the amount of response that is available during any given instant.
- ***Minimum turndown*** - the critical point for electrolyser operation after which the unit must turn off.

- ***Start-up time*** - the time that it takes to start the device. For the results of tests start-up times are separated into two classes: (i) cold start, when the unit has been off for sufficient time to lose benefit from energy stored in the electrolyser (e.g., thermal energy for lubricants and coolants) and (ii) warm start, when the unit has been off or in standby for a short time.
- ***Shut-down time*** - the time that the electrolyser takes to drop load.

It is also important to note that many of the above listed properties have a time-dependent component and can be heavily influenced by the balance-of-plant and control strategies employed for the equipment. For example, the speed at which an electrolyser can increase its load varies if the device is operating at 50% output or at 90% output.

Testing was performed as part of NREL Wind2H2 project which integrated wind turbine and solar photovoltaic generation with load banks, electrolysers, a hydrogen storage system, and a fuel cell, each of which could be connected to an AC or DC bus bar. This enabled the seamless interchange of equipment on the system to explore various configurations.

The testing was performed for a PEM electrolyser manufactured by Proton OnSite and an alkaline electrolyser manufactured by Teledyne Technologies, shown in Table 14.

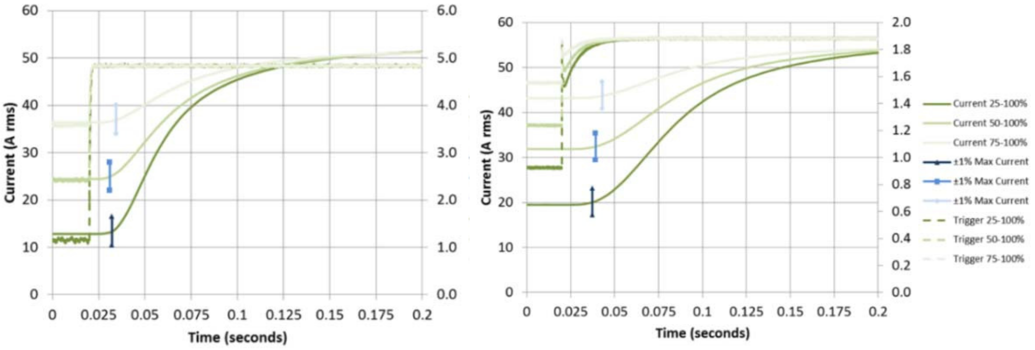
Table 14 Electrolyser parameters

	PEM	**Alkaline**
Manufacturer	Proton OnSite	Teledyne Technologies
Electrical Power	40 kW (480VAC)	40 kW (480VAC)
Rated Current	155 A per stack	220 A, 75 cell stack
Stack Count	3	1
Hydrogen Production	13 kg/day	13 kg/day
System Efficiency at Rated Current	75 (kWh/kg)	95.7 (kWh/kg)

9.4 Review of NREL test results

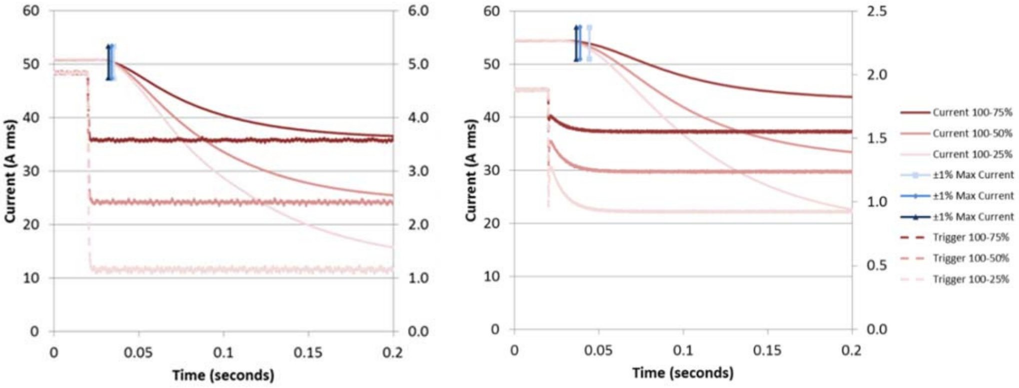
Response time and ramp rate

To test the PEM and alkaline electrolyser ability to ramp, their DC set-points were rapidly changed. Ramp-up and ramp-down tests were performed, with stack set-point changed from 100% to 25% for ramp-down tests and from 25% to 100% for ramp-up tests. In both cases the changes were done for increments/decrements of 25%, and the results are shown in Figure 9.1 and Figure 9.1 Ramp-up tests. The results indicated that the system-level response time for both the PEM and alkaline electrolysers ramping up or down occurred quickly and is nearly complete after 0.2 seconds.



(a) PEM electrolyser (b) alkaline electrolyser

Figure 9.1 Ramp-up tests



(a) PEM electrolyzer (b) alkaline electrolyser

Figure 9.2 Ramp-down tests

The above ramp tests were used to evaluate: (i) the initial response time, which is the time it takes after a set-point change to electrolyser begin changing the output, (ii) the total response time, i.e. how quickly the set-point is achieved and the time it takes for the electrolyser system to settle, and (iii) examination of the ramp rate during the test to determine the maximum achievable ramp rate.

Initial response time

In these tests the initial response time is calculated by the time it takes for the electrolyser to change 1% of maximum current, following the set-point change. This time does not depend only on the electrochemistry within the electrolyser stack, which can occur on the order of microseconds, but can be also affected by the balance-of-plant components (e.g., power supplies) and the control strategy.

Response times for both PEM and alkaline electrolysers tested are summarized in Figure 9.3. After receiving the trigger, the longest time to begin responding with ±1% maximum current was 24.3 milliseconds and the fastest was 11.0 milliseconds, with an average of

16.5 milliseconds. The average delay between the trigger and a 1% change in max current is 0.013 seconds for the PEM unit and 0.019 seconds for the alkaline unit.

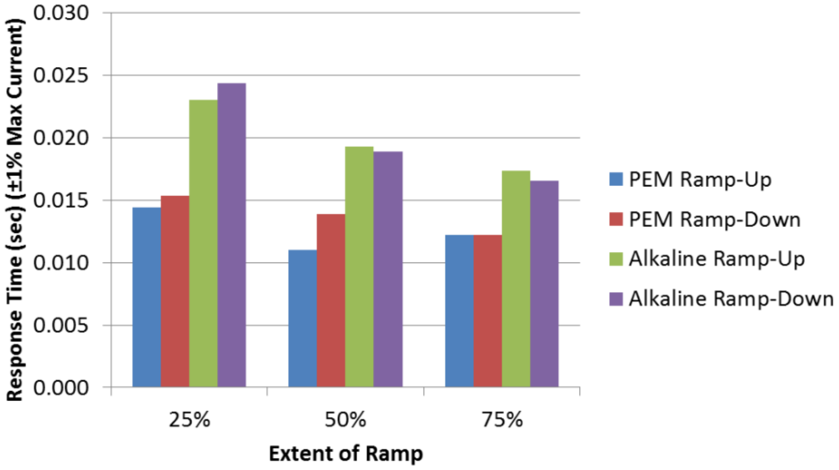


Figure 9.3 Initial response time comparison

Settling time or total response time

Although settling time is significantly influenced by various components (e.g. the power supply), the data showed that the order of system total response time for stack load changes ranging from 25% to 75% is well below 1 second. The data sampling time was limited to only 0.2 seconds; however, a number of the tests had already achieved their set-point by that time, as shown in Figure 9.4 which indicates the level of test completion for each test at 0.2 seconds.

As might have been expected, it takes more time to undergo a larger step change, and thus the greater the set-point change, the less complete the tests are at 0.2 seconds

In both ramp-up and ramp-down tests, PEM electrolyser response was faster. Its ramp-up tests indicated overshoot, thus the values for ramp completion are greater than 100%. The ramp-down tests were slower to reach the set-point and were at most 99.1% complete for the 25% ramp and at the least 96.7% complete for the 75% ramp at 0.2 seconds.

The alkaline tests generally had a slower response for the equipment tested and, like the PEM, were able to settle from the ramp-up faster than from the ramp-down. The average completion for the alkaline ramp-up was 96.8% and for the ramp-down was 92.9% with a minimum value of 91.2%.

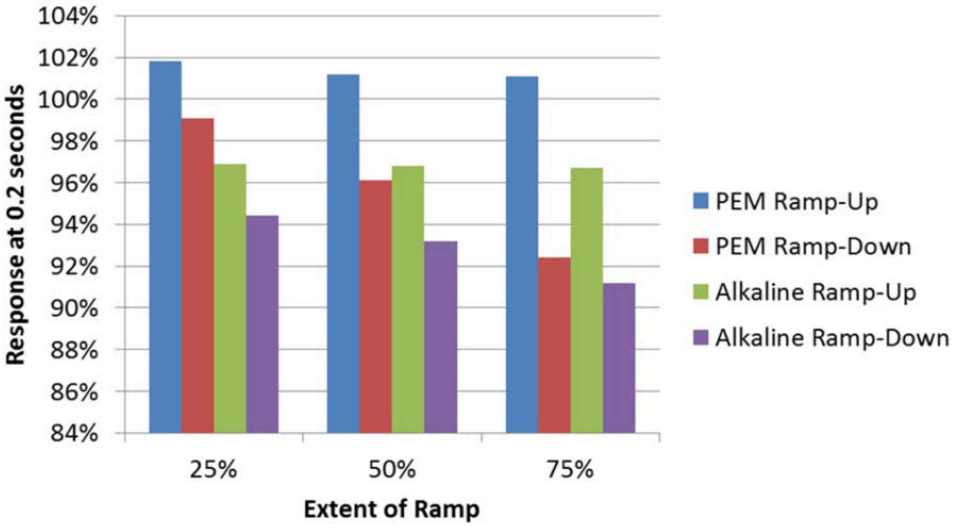


Figure 9.4 Ramp completion at 0.2 seconds

Ramp rate

Maximum ramp rate occurs at the single point of highest slope for ramp-up and down tests and are shown in Figure 9.5. The units are percent of current per second, which means that a value of 200% signifies a unit that, at peak ramp rate, can reduce its current from 100% to 0% or increase its current from 0% to 100% in 0.5 seconds.

This is a single-point measurement and does not include the control strategy. In this case, the maximum ramp rates for ramp-up are larger than those of ramp-down due to the test setup.

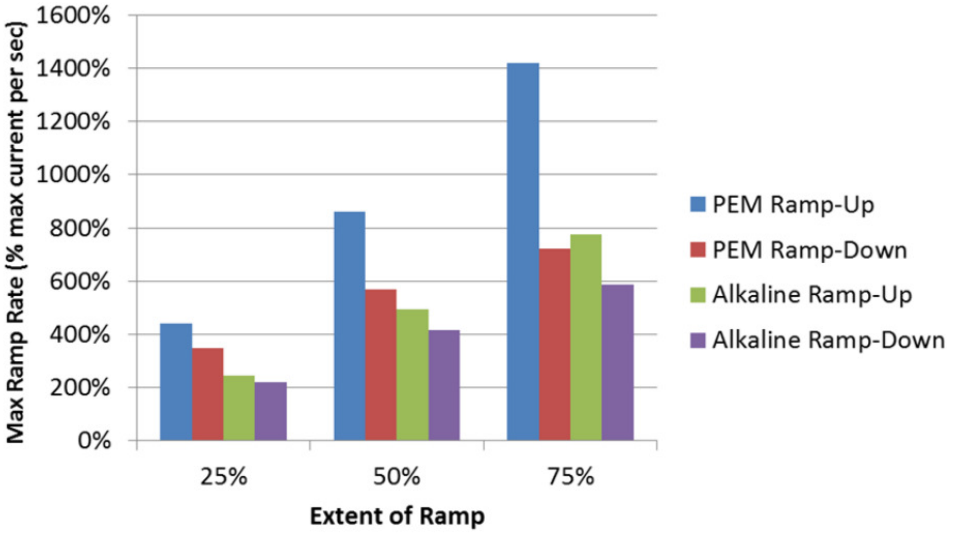


Figure 9.5 Maximum ramping experienced

Turndown

No specific test for minimum turndown was performed, but a variable operation test was carried out for the PEM electrolyser only. The stack current was varied for two stacks in the PEM electrolyser by changing the input current using a signal that is based on a wind turbine generation profile. The output current values for stack 1 and stack 2 are shown in Figure 9.6, but these values do not represent an absolute minimum for the equipment but rather the minimum values that were achieved based on the input signal (which followed a wind profile).

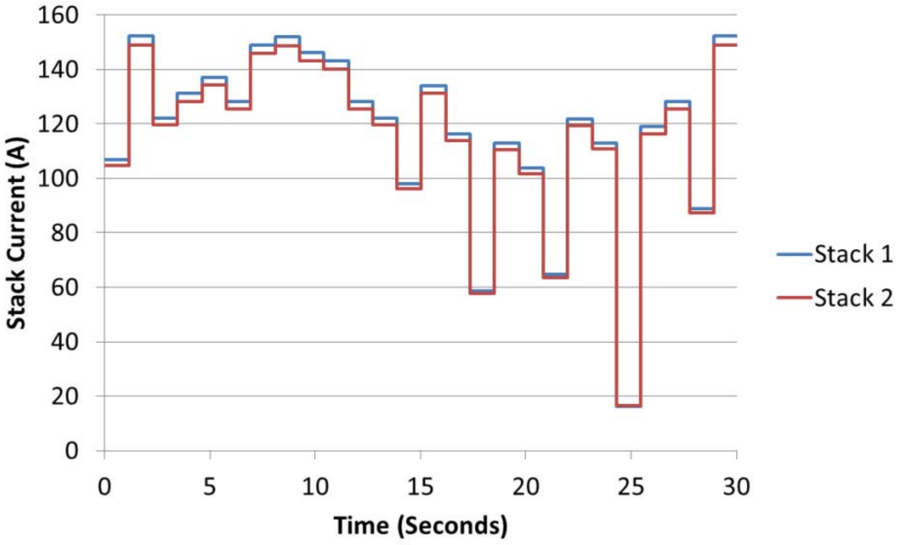


Figure 9.6 Electrolyser variable operation

Start-up and shut-down

For an electrolyser to participate in demand response, the speed a unit can start up and shut down is another important factor. A test was performed to determine how quickly the unit can cold-start and shut down. This was only carried out for the PEM electrolyser.

From the off position to full power and hydrogen generation took 6 minutes and 27 seconds. Power is consumed throughout the start-up process. To shut down, the unit took 1 minute and 3 seconds to go from the full power generating mode (40kW) to the off position.

9.5 Comparison of NREL study to UK application requirements

End-user energy management

For the electrolyser to be able to support the requirements for end-user energy management, it must be able to change its load point rapidly and significantly to make a change in the 15-minute average electricity consumption.

Results of NREL tests discussed above confirm that electrolyser systems can change their load point rapidly, on the order of milliseconds, and can shut down in just over a minute. Additionally, the load-point changes are significant.

Thus, it is possible for electrolysers to provide significant flexibility to change an end user's demand profile and potentially reduce the demand charge. With TOU or RTP rate structures, this flexibility represents an opportunity to reduce the electricity charges by purchasing electricity at a time of low cost and reducing the production during times when electricity costs are high.

However, this flexibility will only be useful for the end user if it is considered together with the storage unit sizing to ensure that sufficient hydrogen is produced and available to meet the hydrogen demand.

Transmission and Distribution support

T&D support requires a response on the order of minutes to hours, for a duration of hours. This is similar to the requirements for end-user energy management. The length of the response, however, will depend on the size of the hydrogen storage. Assuming that there is sufficient hydrogen stored to satisfy the hydrogen demand, network operator may utilize electrolysers located in certain areas of the network to alter the demand profile and avoid reinforcement.

Wholesale market services

Participating in the provision of ancillary services represents an opportunity for the electrolyser equipment to bring additional revenue streams. However, different services have different technical requirements, and the results from the NREL electrolyser testing have been compared to the requirements for the UK (i) regulation markets, (ii) load-following and fast energy markets, and (ii) operating reserve markets.

Regulation

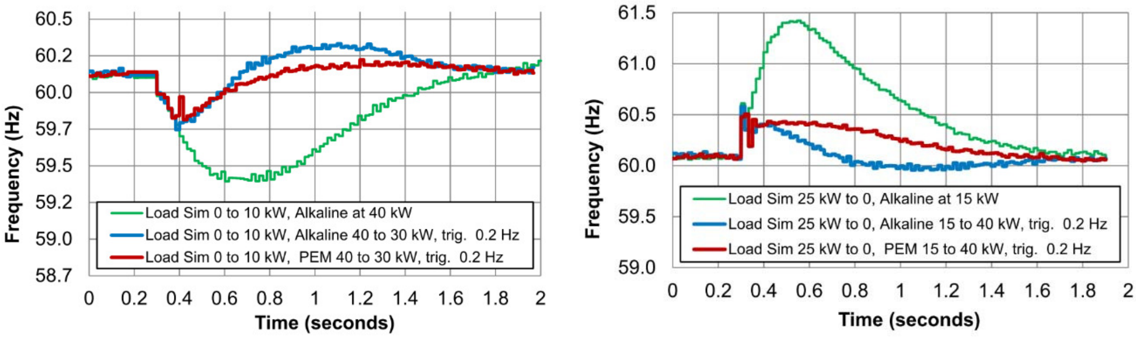
Regulation markets require a response time on the order of minutes, which must be maintained for 30 minutes. The electrolyser systems tested can respond much faster than a minute with response times on the order of hundredths of a second and can significantly change their load point in less than one second. This means that electrolysers can respond quickly enough to participate in regulation markets.

Similarly to the case of end-user management, the requirement of provision that lasts for at least 30 minutes depends on the hydrogen demand and storage capacity to ensure hydrogen supply, when needed.

Tests for PEM electrolyser indicated a very low part-load point, which means that it can bid a significant portion of demand. Similarly, with a low part-load and fast ramping capability, an electrolyser could operate below its rated power point and still provide a response with the remaining capacity.

With sufficient hydrogen storage, an electrolyser can participate in the provision of regulation services; however it is necessary to evaluate the cost related to the size and operation of the storage, as well as wear and tear of the equipment due to fast changes in operating point.

Additional tests were carried out by NREL to assess the ability of electrolysers to provide frequency response. This was done within a microgrid as detailed in [14]. As shown in Figure 9.7, allowing the electrolysers to help compensate for load perturbations can provide frequency regulation support for the grid.



(a) Load increase *(b) Load shed*

Figure 9.7 Load frequency support for alkaline and PEM electrolysers

Load-following and fast energy markets

Load-following and fast energy markets have more relaxed requirements for the response time but have greater requirements for the duration. A unit participating in the load-following or fast energy market must respond within ten minutes and maintain the response for between ten minutes and several hours.

As discussed previously, testing shows that PEM and alkaline electrolysers can respond much quicker than the required ten minutes. However, providing energy for longer durations may require additional hydrogen storage capacity or oversizing the electrolyser unit.

Operating reserves

Requirements for the provision of spinning and non-spinning operating reserves, set by the system operator, are that the response time must be less than ten minutes with durations up to 2 hours, while for replacement or supplemental reserves, the response time must be less than 30–60 minutes for a duration of 2 hours.

The ramp down speed for electrolysers is sufficiently fast to provide operating reserves by turning down part of the electrolyser capacity (on the order of seconds) or the total unit capacity by turning off the electrolyser (63 seconds for the PEM unit). Thus, it can provide the demand reduction for extended periods of time because it represents turning the electrolyser down or off, which can be done rapidly and reliably.

Summary

The results for participation in the electricity markets are summarized in Figure 9.8, with requirements for the participation based on Kirby 2006 [21].

The 40kW Electrolyser used in [14] can respond faster than the required response time for spinning reserve and regulation (i.e. lower than the blue bar) and for longer duration than required for load-following and replacement/supplemental reserve (i.e., higher than the red bar). This shows that, technically, electrolysers have sufficient flexibility to participate in all of the aforementioned electricity markets.

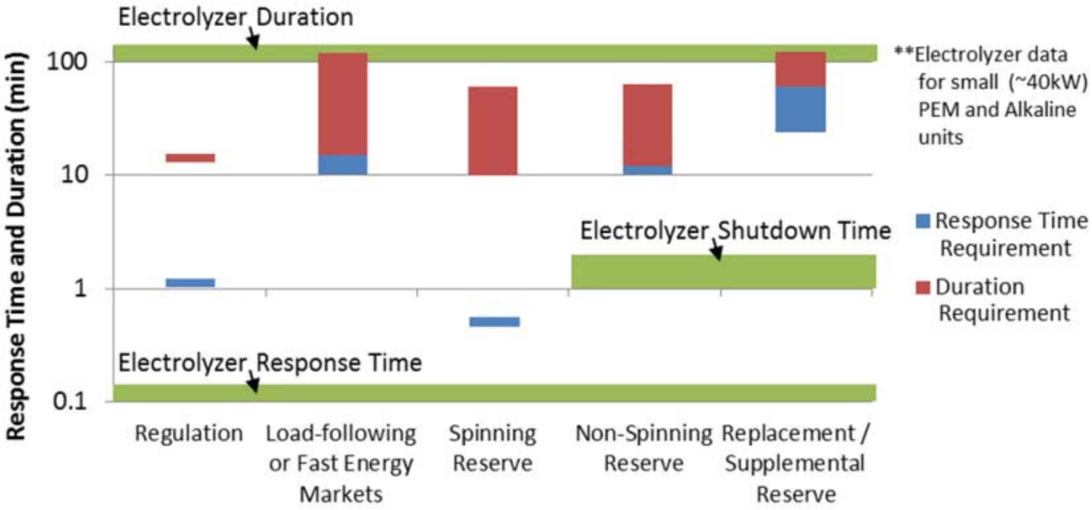


Figure 9.8 Summary of electrolyser flexibility compared to electricity market requirements [14]

9.6 NREL test conclusions

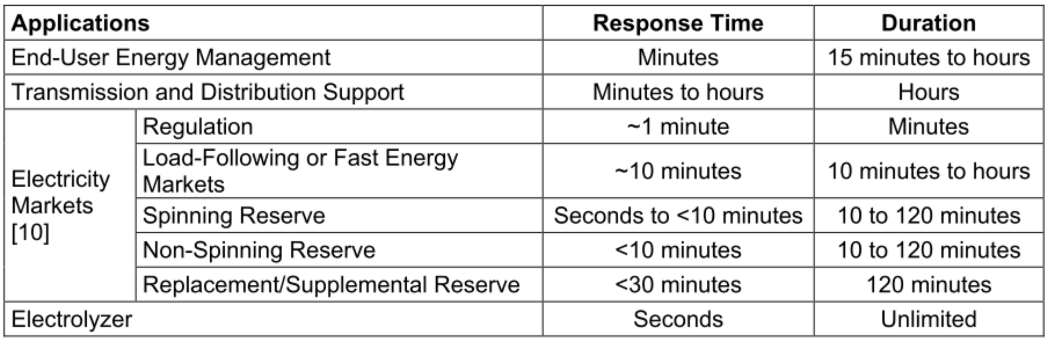
Results from the testing using a PEM and an alkaline electrolyser to assess the ramping, variable operation, frequency disturbance correction, and start-up and shutdown capabilities show the following:

- **Small electrolyser systems (~40kW) began changing their electricity demand within milliseconds of a set-point change**. The PEM unit responded within an average of 13.2 milliseconds, while the alkaline unit responded within an average of 19.9 milliseconds.
- **The settling time after a set-point change is on the order of seconds**. Every demand change value (25%, 50%, and 75%) for both electrolyser types settled to the prescribed set-point in less than 1 second.
- **Electrolysers can reduce their electrical consumption for an unlimited amount of time**. However, other safety and control systems (e.g., system pressure and gas crossover) may need further design considerations to accommodate the lower production levels.
- **Larger set-point changes were associated with higher maximum ramp rates**. Ramping up an electrolyser had higher maximum ramp rates than while ramping down.

- **Electrolysers exhibit low part-load operation capabilities**. During the variable operation test the unit was turned down to 10% part-load.
- **Electrolysers can start up and shut down quickly**. For the small unit tested (~40 kW), it took 6 minutes and 27 seconds for the PEM unit to execute a cold start and 1 minute and 3 seconds to turn off.

The findings regarding requirements for supporting end-user energy management, transmission and distribution system support, and wholesale electricity markets compared to the requirements for providing each service are summarised in Table 15.

Table 15 Summary of Response Time and Duration for Each Application [14]



Applications		Response Time	Duration
End-User Energy Management		Minutes	15 minutes to hours
Transmission and Distribution Support		Minutes to hours	Hours
Electricity Markets [10]	Regulation	~1 minute	Minutes
	Load-Following or Fast Energy Markets	~10 minutes	10 minutes to hours
	Spinning Reserve	Seconds to <10 minutes	10 to 120 minutes
	Non-Spinning Reserve	<10 minutes	10 to 120 minutes
	Replacement/Supplemental Reserve	<30 minutes	120 minutes
Electrolyzer		Seconds	Unlimited

Note that unlimited duration of the electrolyser reported by NREL requires adequate hydrogen storage to meet any associated hydrogen demand.

Based on the above comparison table, the following conclusions were made:

- **Electrolysers acting as demand response devices can respond sufficiently fast and for long enough duration to participate in energy management on the utility scale and at end user facilities**. Hydrogen storage capacity and controls should be designed with specific applications in mind and can be different for different applications.

- **Favourable operating properties and a variety of potential system architectures contribute to the flexibility of electrolyser systems.** Electrolysers can operate as a stand-alone device, participating in one or more of the ancillary services provision while also providing hydrogen product for sale.