

A TECHNO-ECONOMIC ANALYSIS OF THE BENEFITS OF AQUEOUS
PHASE REFORMATION FOR HYDROGEN ENRICHMENT OF NATURAL GAS
ENGINES AND TURBINES

By

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ABSTRACT

A TECHNO-ECONOMIC ANALYSIS OF THE BENEFITS OF AQUEOUS PHASE REFORMATION FOR HYDROGEN ENRICHMENT OF NATURAL GAS ENGINES AND TURBINES

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Aqueous phase reformation (APR) for hydrogen enrichment of natural gas power plants is a developing technology with a range of environmental benefits that include the displacement of fossil fuel with renewable feedstocks derived from biomass, reduced NO_x emissions, as well as increased efficiency and thus lower carbon intensity of generated power. However, to date, aqueous phase reformation has only been tested at lab-bench scale, and the economic viability of a full-scale reactor for a hydrogen enrichment system is unclear. A comprehensive analysis of the economic value of these benefits will provide researchers with a better understanding of the value of this technology. When an APR for H_2 enrichment system is applied to a 23 MW natural gas engine, the benefits have an estimated combined value of 1.87 ¢/kWh produced and a present value of \$33 million. When applied to a 100 MW natural gas turbine the estimated combined value of the aforementioned benefits is 1.55 ¢/kWh and present value of \$155 million.

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INTRODUCTION

Today, the world is facing the greatest anthropogenic, environmental problem ever encountered: carbon pollution from fossil fuel combustion raising atmospheric concentrations of greenhouse gases (GHGs) leading to climate change. The global nature of the problem demands a diverse solution from not just one sector, but from all contributing areas of GHG emissions including transportation, power, cooking and heating.

ENERGY DEMAND INCREASING

According to the International Energy Agency (2013), total world energy consumption nearly doubled between 1973 and 2011, from 4,674 million tonnes of oil equivalent (Mtoe) to 8,918 Mtoe. Furthermore, consumption is expected grow to between 10,000 and 12,000 Mtoe by 2035. World electricity generation from natural gas is also on the rise, from 12.2% of 6,115 terawatt-hour (TWh) (or 746 TWh) to 21.9% of 2011 total electricity generation of 22,126 TWh (or 4846 TWh). Increasingly, natural gas turbines and engines are replacing old, coal-fired power plants and being employed to convert the relative clean, cheap fossil fuel into electricity at high efficiencies and with low emission rates (Cho and He 2007; Sniderman 2012).

ENVIRONMENTAL CONCERNS OF ENERGY CONSUMPTION

While energy access is critical to sustain the global population today, it must be balanced against its environmental impacts. As human population increases globally, and particularly, as developing nations continue to raise their citizens out of poverty and into the consuming middle-class, providing sustainable, environmentally friendly energy is a large and commendable challenge.

Climate Change

According to the Intergovernmental Panel on Climate Change (IPCC) (2013) since the 1750s, atmospheric CO₂ concentrations have increased worldwide from 280 to 391 ppm in 2011, a 40% increase due to anthropogenic combustion of fossil fuels. The increase of CO₂ concentrations and GHGs more generally, has yielded an increase in radiative forcing on Earth. Consequently, the IPCC believes with a 95-100% confidence level that the increase in anthropogenic GHG emissions is the driving cause to both oceanic and atmospheric warming, melting snow and ice and subsequent global sea level rise.

Continued carbon emissions will result in even more extreme climate changes, and mitigation is only possible through a substantial reduction in GHG emissions.

The impacts of climate change on human society are large and many. Some of the most concerning include food and water security. Karl et al. (2009) describes a climate with more extreme precipitation patterns increasing the frequency of both droughts and floods.

Additionally, snow pack melt will continue to occur earlier and earlier in the season, and water resources in stressed environments will likely become even more limited. Equally concerning, Wheeler and von Braun's (2013) research suggests that climate change could exacerbate food security problems in regions of the world already facing hunger and malnutrition. Furthermore, sea level rise coupled with increased storm intensity can have dire impacts for coastal communities including displacement.

Criteria Pollutants and Toxic Emissions

The Clean Air Act, passed in 1970, requires of the EPA to set air quality standards for pollutants that pose a public health concern including nitrogen dioxide, ozone, particulate matter, carbon monoxide, sulfur dioxide and lead (US EPA 2013). NO_x , however has both human and environmental health concerns, and is an emission of concern from all natural gas engines and turbines. It is a standalone air pollutant that can react with other compounds to form products with mutagenic properties, and on its own can cause and exacerbate chronic respiratory conditions. NO_x also reacts with O_2 to form undesirable ozone (O_3) in the troposphere, which is the principle component of smog and causes health impacts for humans and animals as well as damage to crops and other plants. Conversely, NO can bond with O_3 in the stratosphere creating new NO_2 and O_2 , and thus deplete beneficial, ultraviolet radiation blocking O_3 . Beyond human health concerns, NO_x emissions have detrimental environmental impacts. It can dissolve into moisture in the air, forming nitric acid (HNO_2 or HNO_3), or acid rain. The resulting precipitation can cause unwanted acidification, nutrient loading and eutrophication in exposed watersheds

and even threaten human health through the deposition and high concentrations of hazardous nitrates in drinking water (US EPA 1997; 1999).

Due to these emissions' impacts, many regions of the country have set strict emission limits on internal combustion engines and turbines requiring expensive add-on control technologies to satisfy regulations. Many regions have also implemented market-based strategies to limit the amount of NO_x emitted by establishing a banking program to buy and trade emission reduction credits (ERC) earned through cutting emissions below regulated levels (Evolution Markets 2014). The price of a ton of NO_x varies between air quality districts in the state of CA but also is subject to change over time. For example, the average price for a ton of NO_x ERC in the South Coast district in 2013 was \$80,138 (CARB 2014₂) up from \$24,658 the year before (CARB 2013₂).

MITIGATING DETRIMENTAL IMPACTS OF ENERGY CONSUMPTION

In a world of growing energy demand, natural gas has become increasingly popular as a power generating fuel and will continue to grow well into the 21st century. The low cost of natural gas makes it an easy replacement for old, base load, more polluting, coal-fired power plants. Additionally, production of natural gas is increasing in the US, particularly from unconventional sources like shale gas, tight gas, and offshore reserves (US EIA 2014₁).

While this path may offer a reduction in carbon intensity of electricity generated, it continues to rely on carbon-emitting fossil fuels. Further concerning, Brandt et al. (2014) warns that any carbon savings made by switching from coal to natural gas may be negated by leaks due to the high global warming potential of methane. Therefore, the extraction and distribution of natural gas should be done carefully, and once extracted its use should be optimized for maximum efficiency, as well as minimum CO₂e and NO_x emissions.

To avert the worst of climate change, greenhouse gas emissions from fossil fuel sources must be curbed. While there are many carbon neutral renewable energy technologies, few are easily integrated into our fossil fuel based infrastructure. Biologically derived fuels are the exception and can be suitable replacements or amendments within many fossil fuel systems. In addition to having a lower carbon-intensity than fossil fuel, hydrogen, including that which is biologically derived can even enhance the efficiency of a pre-existing system while simultaneously reducing NO_x emissions (Sierens and Rosseel 2000).

Waste heat driven aqueous phase reformation (APR) for H₂ enrichment is a nascent technology that recuperates waste heat of a natural gas engine or turbine to reform a biologically derived feedstock into H₂ and other combustible gases displacing a fraction of natural gas with the biologically derived syngas. APR is desirable for its ability to

recuperate waste-heat, employ low-carbon fuels, and convert them into a syngas with a high H₂ content.

GOALS OF THIS THESIS

In an attempt to interpret the potential economic value of APR for H₂ enrichment, a significant literature review was conducted on the APR technology, the impact of H₂ enrichment on natural gas engines and turbines, the technology and cost of current emissions reduction technologies, and the market value of emissions reductions and renewably derived power. This literature review has supplied the inputs for the Methods section, which is a techno-economic analysis of APR for H₂ enrichment's potential to displace both capital and variable costs at a generating station, as well as its capacity to increase revenue by leveraging regulations and markets that incentivize low CO₂e and NO_x-emission power. To standardize the various data into one comprehensive economic metric, cents per kilowatt-hour (¢/kWh) generated has been chosen to represent the cash flow of APR for H₂ enrichment at a natural gas engine or turbine power plant. The values from the various benefits have been summed and converted to a present value to provide an estimate of the economic viability of the APR for H₂ technology. In other words, a ceiling price has been estimated for which the APR for H₂ enrichment system must fall beneath in order to be an economically feasible option for a power producer.

The specific benefits of APR for H₂ enrichment that will be financially analyzed occur in the following groupings and order:

- First, APR for H₂ enrichment reduces the amount of natural gas needed to operate the system through both direct displacement of natural gas with biologically derived fuel, and also through increased thermal efficiency of the overall system due to the endothermic conversion of waste heat into additional chemical energy in APR and the enhanced combustion properties of H₂ enriched natural gas.
- Second, APR for H₂ enrichment can eliminate the need for other NO_x reduction technologies, thus displacing their costs. Often natural gas engines and turbines are fitted with expensive selective catalytic reduction (SCR) systems to reduce NO_x levels to enforced limits. Beyond that, H₂ enrichment has the potential to reduce NO_x even below regulations, and the difference in allowed and actual emissions can be sold as Emission Reduction Credits through the Californian market. Both the displaced cost of control technology and the emission reduction credits add to the economic value of APR for H₂ enrichment for engines and turbines.
- Finally, the value of low-CO₂e power will also be assessed through California regulatory markets including Cap-and-Trade and a financial incentive that, in theory, applies to APR for H₂ enrichment, the Renewable Market Adjustment Tariff (ReMAT).

In conclusion, these values will be summed to represent the potential economic worth of APR for H₂ enrichment per unity electricity generated. This value will then be used to calculate the present value of this system representing the economically viable maximum

cost of the technology. By analyzing the value to this developing technology, a better understanding of its feasibility will be achieved and will aid in the decision-making regarding research and development of this technology.

REVIEW OF LITERATURE

The following is a review of the literature providing the background necessary to analyze the potential value of APR for H₂ enrichment of natural gas engines and turbines. A clearer picture of APR for H₂ enrichment as it applies to large natural gas engines and mid-sized natural gas turbines has been developed through a thorough search of manufacturer literature, academic journals, reviews, governmental publications, and governmental regulations.

AQUEOUS PHASE REFORMATION

Aqueous phase reformation (APR) is an endothermic, thermochemical reaction that occurs over a metal catalyst to reform carbohydrates in aqueous form to a hydrogen rich syngas (Cortright et al. 2002). The reaction can be driven at a range of temperatures, but experiments are often conducted between 473.15 and 538.15 °K (Cortright et al. 2002; Huber et al. 2003; Cruz et al. 2008; Shabaker et al. 2003). Under these APR operating temperatures, the reactor chamber must be pressurized to ensure the solution stays in liquid phase. Accordingly, the pressures at which APR occurs must be above those of the vapor pressure of the solution at the operating temperature, or greater than 1,500 and 5,600 kPa (>220 and >812 psig) (Cortright et al. 2002; Cruz et al. 2008; Severy 2013).

Shabaker and Dumesic (2004) describe the chemical reactions that take place over the catalyst reforming a sugar-alcohol, showing that the feedstock first undergoes

dehydrogenation releasing H₂ molecules, and then the C-C bonds are cleaved yielding CO. The complete reformation of glycerol can be seen in the following three equations. Equation 1 begins the process with dehydrogenation.



The CO is then converted to an additional H₂ in the presence of water via the water gas shift reaction as seen below in Equation 2.



An overall stoichiometric reaction would therefore yield seven molecules of H₂ per molecule of glycerol as seen in Equation 3.



Assuming that water has no available chemical energy and that the reaction is complete with no side products, this endothermic reformation process increases the chemical energy of the glycerol reactant by about 14.5%. While the equations above show a straightforward, stoichiometric conversion, APR often produces side products or incomplete conversion yielding reaction intermediates including alkanes, alcohols, ketones, aldehydes, and acids (Kirilin et al. 2010; Shabaker and Dumesic 2004).

Feedstocks

In addition to glycerol, the APR reaction can occur using a wide variety of aqueous

oxygenated hydrocarbons. Molecules with a carbon-to-oxygen ratio of one-to-one are commonly used in APR experiments, including glucose ($C_6H_{12}O_6$), sorbitol ($C_6H_{14}O_6$), ethylene glycol ($C_2H_6O_2$), and methanol (CH_4O) (Cortright et al. 2002). Additionally, direct reformation of cellulose has been proven under APR in one-pot reactors by Wen et al. (2010) and woody biomass after acid hydrolysis by Valenzuela et al. (2006).

Catalysts

A wide variety of catalysts have been tested in APR experiments. Many of which are precious metals, such as Pt, Pt-Re, Pd, Ru, Rh, and Ir (Davda and Dumesic 2003; Davda et al. 2005; Meryemoglu et al. 2010) supported on various oxides such as Al_2O_3 , CeO_2 , ZrO_2 , and MgO (Menezes et al. 2011) or on carbon or activated carbon (King et al. 2010). Metal loading varies between catalysts and experiments, but 3% by weight is not uncommon, and up to 17% has been tested (Davda and Dumeisc 2003; Wen et al. 2008). Other catalyst materials include Ni- B_2O_3 amorphous alloy and Raney-Ni (Guo et al. 2012).

Relevant Thermodynamics

As mentioned above, APR is an endothermic thermochemical reaction, which can increase the chemical energy of reactants to products by 14.5%, if conversion is complete. Therefore, thermal energy can be captured in the chemical reformation of aqueous carbohydrates to H_2 , CO, CH_4 , and other low weight alkanes. Severy (2013) found that exhaust temperatures of $873^\circ C$ at exhaust flow rates of 2.3 kilograms/second

(kg/s) could increase the chemical energy of an aqueous glycerol feedstock by 6%, while only a 3.4% increase was achievable at lower 385°C temperature with a higher exhaust flow rate of 3.8 kg/s. In this analysis, no side products were evaluated and all unconverted feedstocks were assumed to remain as glycerol.

In practice, however, complete stoichiometric conversion is unlikely, and for the purposes of this analysis, only a conservative 5% increase in chemical energy will be applied to the conversion from reactants to products. In this way, 1 joule of biologically derived feedstock can become 1.05 joules of renewable combustible gases, and some of the waste thermal energy of the exhaust gas is converted into additional chemical energy and recycled back to the combustion process as fuel.

Theoretically, the exhaust gases of internal combustion engines provide sufficiently hot waste heat to drive the endothermic reaction (Botti, et al. 2004; Chheda et al. 2007). In practice, Bueno and de Oliveira (2013) have published research recuperating the waste heat of an internal combustion engine to drive vapor phase reformation (VPR) reactions. Vapor phase reformation requires temperatures above the boiling point of the feedstock solution, around 600-1000K at ambient or slightly higher pressures, around 14-71 psig for a 57% wt/wt glycerin feedstock (Adhikari et al. 2007), while Bueno and de Olivera (2013) steam reformed glycerol feedstocks of 10-90% by weight at temperatures ranging from 873-1073K. The relatively low reaction temperature of APR in comparison to VPR allows for greater heat recovery from internal combustion engines and turbines (Severy

2013).

Even high efficiency engines with relatively low exhaust temperatures such as the 18.8 MW_e engine available from Wartsila, 18V50 SG has sufficient exhaust heat flow at temperatures of 648°K +/- 15°K (exhaust gas flow: 31.0 +/- 5kg/s; exhaust gas energy: 11,911kW) to drive the APR reaction (473-538°K) but is less likely to transfer sufficient heat for the higher temperature VPR reaction (600-1000°K) (Wartsila 2012; Severy 2013). Additionally, coupling APR with an internal combustion engine or gas turbine not only serves to drive the thermochemical reaction, but the pairing also provides a direct application for the hydrogen rich syngas through a process called H₂ enrichment, described below in detail. A visual representation of this system is provided in Figure 1.

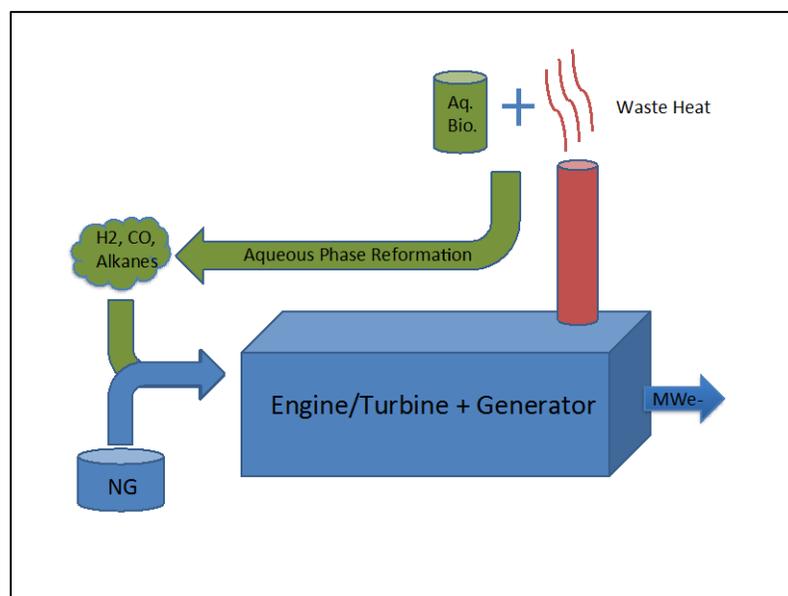


Figure 1. Block diagram of APR for H₂ enrichment system of natural gas prime mover and generator. Heat recuperated through the APR process is added to the aqueous solution of biomass derived feedstock (Aq. Bio.) chemical energy and reformed to H₂ and other combustible gases, which are used to displace some of the natural gas fuel.

HYDROGEN ENRICHMENT

Hydrogen enrichment is the addition of hydrogen gas to the primary fuel stream input of a combustion process. The impacts of hydrogen enrichment are varied depending on the initial fuel used, the combustion technology, operating conditions, and the concentration of hydrogen added to the fuel stream. However, prior research suggests that hydrogen enrichment of natural gas engines and turbines has strong potential to improve the combustion characteristics within the system. In this analysis, the impacts of hydrogen enrichment on natural gas internal combustion engines and turbines will be assessed independently. In addition to improved combustion characteristics, hydrogen enrichment using hydrogen produced from renewable sources displaces a portion of the fossil fuel needed to generate power. In APR of biomass derived carbohydrates, the hydrogen rich gas is assumed to be carbon neutral and hydrogen enrichment reduces the carbon intensity of the generated electricity.

The benefits from hydrogen enrichment are due to the fact that hydrogen has substantially different combustion properties than natural gas. The following table has been adapted from Smutzer (2006) using data available in Glassman (1996) and provides a comparison of the two fuels.

Table 1. Combustion property comparison of natural gas and hydrogen (Smutzer 2006; Glassman 1996).

Metric	Natural Gas	Hydrogen
Lower Heating Value (MJ/kg)	42	120
Lower Flammability Limit (Volume %)	5	4
Higher Flammability Limit (Volume %)	15	75
Stoichiometric Ignition Energy (mJ)	0.34	0.019
Stoichiometric Laminar Flame Speed at 1 atm (cm/sec)	40	200

Natural Gas Internal Combustion Engines

Natural gas internal combustion, reciprocating engines are most commonly used to power pumps and compressors throughout the natural gas industry (US EPA 2000₁). However, natural gas engines are increasingly employed as power plants. One company leading this market is Wartsila, who produces large 4-23MW engines for stationary power generation as well as for marine shipping. To increase capacity, the modular engines can be grouped in parallel. Engine power plants can convert fuel to electricity with high efficiencies of 46-49%, and each individual engine may be ramped up or down quickly in order to follow load while maintaining high efficiency (Wartsila 2014).

Natural gas combustion produces fewer particulate matter and sulfur dioxide emissions than other fossil fuels and therefore has the added advantage of more easily achieving air quality limits set by regional regulators (Eastern Research Group 2001). Still, emission reduction technologies are needed to achieve most regulated emission levels.

Efficiency Improvements

Hydrogen enrichment of natural gas internal combustion engines has been experimentally tested by a number of researchers to determine the impact hydrogen addition has on thermal efficiency. Ma et al. (2010) have characterized the response of a natural gas engine to hydrogen enrichment. At 30% hydrogen and 70% natural gas by volume, Ma et al. (2010) found that the thermal efficiency can be significantly increased at any air ratio as long as the engine's spark timing has been optimized for the different combustion characteristics of hydrogen. In a hydrogen enrichment study out of the University of Gent, Belgium, it was found that a 10% addition of hydrogen by volume improved engine efficiency over pure natural gas (Sierens and Rosseel 2000). Huang et al. (2006) found that the addition of 20% or greater hydrogen enrichment by volume to natural gas yielded an increase in the effective thermal efficiency of the spark ignition engine. Similarly, Akansu et al. (2004) determined that 30% hydrogen enrichment by volume to a natural gas fueled internal combustion engine can increase thermal efficiency by 8.1% compared to the same engine operating on 100% natural gas at an equivalence ratio of 0.80. Finally, Swain et al. (1993) provides further support of efficiency increases from H₂ enrichment as they found 20% hydrogen and 80% natural gas by volume provided about a 10% increase in thermal efficiency over similar operating conditions with pure natural gas.

However, contradicting research has been published. For instance, Ma et al. (2007) found that H₂ enrichment resulted in no thermal efficiency increase when the engine was operated with an excess air-fuel ratio of less than 1.5. The researchers speculate this

unexpected result was due to suboptimal spark timing for the faster burning blend of hydrogen and natural gas.

Emissions Reductions

Sierens and Rosseel (2000) also tested the impact of hydrogen enrichment on emissions production in a spark ignition engine. They found that NO_x emissions could be reduced by the addition of hydrogen to natural gas under both lean and rich burns conditions. When burning lean, the combustion temperature was reduced thus producing less NO_x and when burning rich, there was insufficient available oxygen to create high levels of NO_x emission (Sierens and Rosseel 2000).

Similarly, Hoeksta et al. (1995) found that 28% and 36% H₂ enrichment of natural gas by volume allowed lean engine operation without knock and reduced NO_x levels of the exhaust stream to 28 ppm and 12 ppm respectively at a 0.625 equivalence ratio. Botti et al (2004) determined that because H₂ enrichment with lean operation reduces peak cycle temperatures, it has a beneficial impact on NO_x emissions, reducing their levels by about one-third. Still other research suggests that hydrogen enrichment of 10% by energy, just less than 30% by volume, could enable ultra-lean operation to reduce NO_x emissions to as low as 4ppm corrected to 15% O₂ in a biogas fueled reciprocating engine (Smutzer 2006; Wilson 2012).

Congruently, research by Kornbluth et al. (2010) determined that 40% by volume

hydrogen enrichment of landfill gas, which is primarily composed of methane, could reduce NO_x emissions below 0.22 g/kWh in accordance with future California regulations while still maintaining nearly all of the baseline power.

However, some research suggests that NO_x emissions may actually increase as a result of hydrogen enrichment. One such study found that if spark timing was not appropriately optimized for part hydrogen combustion, NO_x levels increased (Ma et al. 2007).

Additionally, Swain et al. (1993) found brake specific NO_x of a hydrogen-methane mixture was generally higher than pure methane at low equivalence ratios. However, at higher equivalence ratios, nearing 1, the hydrogen-methane mixture showed no increase in brake specific NO_x over pure methane fuel. These results are explained by the fact that hydrogen does combust at a higher temperature than methane, and therefore has the potential to increase thermal NO_x production. However, H₂ enrichment also extends the lean burn limit of engines, and if properly tuned and operated at a high air-to-fuel equivalence ratio, NO_x emissions can be reduced further than for combustion of natural gas without hydrogen enrichment.

Natural Gas Turbines

As demand for power grew in the late 1990s, power shortages became increasingly common throughout the United States. Consequently, the price of peak power increased and the market responded by purchasing large numbers of natural gas turbines to operate

during peak load hours (USDE 2000). More recently, high efficiency natural gas turbine power plants are replacing older, coal-fired power plants. Modern simple-cycle natural gas turbines generally have a thermal efficiency between 35 and 46% (Reale 2004; Forecast 2011; Siemens 2014). They range in size from small 200-250kW units all the way up to large 350+MW turbines (Forecast 2011). Combined-cycle natural gas turbine power plants can reach efficiencies of 55-60%, which represents a large fuel savings in comparison to inefficient coal-fired power plants that average about 33% fuel to power conversions (GE 2013; Carapellucci and Giordano 2012; IEA 2012; Najjar 2001). This trend is even more pronounced in regions of the world that import, and thus pay a premium, for their fuel (Sniderman 2012).

Similar to its application in engines, natural gas combustion in turbines produce fewer particulate matter and sulfur dioxide emissions than turbines using other fossil fuels and natural gas turbines are one of the cleanest power generating technologies (Eastern Research Group 2001; Energy and Environment Analysis 2008). However, natural gas turbines do create significant thermal NO_x due to the high combustion temperatures of the system (US EPA 2000₂).

Efficiency Improvements

While hydrogen enrichment of gas turbines does not yield as large an efficiency improvement as in gas engines, there are still benefits of its use in turbines, primarily from improved combustion efficiency and flame stability. Anderson (1975) found that

near complete combustion of propane in a burner could occur at leaner equivalence ratios as more hydrogen is added to the fuel stream. Similarly, a study out of Sandia National Laboratories found that hydrogen addition of less than 5% by mass, increased combustion speed and improved the combustibility of the fuel achieving up to 100% complete combustion, thereby improving the overall efficiency of the turbine (Pechlivanoglou 2007).

Emissions Reductions

Hydrogen enrichment also allows gas turbines to operate at a lower fuel-to-air equivalence ratio (Juste 2006; Schefer 2001). Lean operation decreases the combustion temperatures by increasing the thermal mass relative to the input fuel energy and thus also reduces thermal NO_x production. Correspondingly, Schefer (2003) found that 20% addition of hydrogen by volume to a methane-air mixture stream extended the lean stability limit of the flame by about 15% in comparison to lean operation with pure methane. Ultra-lean combustion allows for lower flame temperatures and consequently a reduction in thermal and overall NO_x production. Even as long ago as 1976, research was being conducted on the emissions reductions capabilities of hydrogen enrichment of aircraft gas turbines. This study found that a 10-12% addition by mass yielded ultra low emissions reducing NO_x levels below 1.0 g/kg fuel (Clayton 1976).

More recently, Termaath et al. (2006) conducted hydrogen enrichment experiments on midsized (30-150 MW) gas turbines. In these experiments hydrogen was added at 10%,

20%, and 30-40% by volume to the natural gas input. Increases in flame stability allowed for leaner operation resulting in decreasing NO_x emissions of 3-4ppm, 2-3ppm, and down to 1ppm, respectively. However, at ultra-low fuel equivalence ratio there is a tradeoff between NO_x and CO emissions, but because H₂ enrichment lowers the lean combustion limits, the fuel mixture can be optimized to reduce the emissions of both pollutants (Maughan et al. 1996). Conversely, Juste (2006) found that up to 4% addition of hydrogen by weight at a constant 0.3 equivalence fuel-air ratio did not result in significant reduction of NO_x production. Juste, (2006) however reports that leaning the primary zone of combustion is an effective means to decrease thermal NO_x production in gas turbines. This suggests that the NO_x emissions impact of hydrogen enrichment is dependent on the hydrogen concentration, the fuel-to-air equivalence ratio, and the combustor design.

VALUE OF BENEFITS FROM APR FOR H₂ ENRICHMENT TECHNOLOGY

Today, the benefits of APR for hydrogen enrichment are met by a number of existing technologies to which our markets and governments have already assigned value. Some of these values represent avoided costs for the power generating entity, while others represent value added products and increased revenue. For both cases, the value of these economic factors can be summed to describe the potential overall value of APR for H₂ enrichment.

Displaced Natural Gas

Pacala and Socolow (2004) have identified reducing the carbon intensity of power generation as one effective solution to mitigate GHG emissions and climate change. One mechanism by which to do so is to employ the use of biomass-derived fuels to replace fossil fuels. Another mechanism included by Pacala and Socolow (2004) to reduce GHG emissions is to improve the efficiency of power generating equipment, thereby producing more electricity per unit of fuel consumed or CO₂ emitted. APR for hydrogen enrichment leverages both of these options in pursuit of climate change mitigation and sustainable energy.

Biologically Derived Fuels

Fuels derived from biomass have a lower carbon-footprint than fossil fuels because biologically derived fuels have captured their carbon footprint throughout the growing season via photosynthesis. Fossil fuels however, contain stores of carbon that have been removed from the atmosphere and sequestered from the biotic system for tens of millions of years (US EIA 2014₄). Fossil fuel CO₂ emissions represent a net gain in atmospheric concentration, while biologically derived fuels have the potential to maintain a constant level through a balance of CO₂ uptake via photosynthesis and emissions during combustion.

Efficiency Improvements

Natural gas engines and turbines operate by combusting fuel in air, which expands to drive a piston in an engine, or to push blades in a turbine, and in both to then spin a shaft and generate electricity. However, much of the thermal energy released during combustion is lost from the system in the form of hot exhaust gases. In fact, exhaust gas temperatures of engines range from 728-922°K, while the exhaust stream temperatures of gas turbines are typically 728-783°K (US EPA, 2008). Therefore, much of the energy supplied to the engine or turbine is lost as waste heat. There are however, technologies that can recuperate this heat and use it to drive a turbine-generator and produce more electricity, without any additional fuel.

Bottoming Cycles

Rankine bottoming cycles recuperate waste heat in exhaust streams of engines and turbines to drive a working fluid through a turbine-generator, thereby producing additional electricity while maintaining the same input of fuel. In this way, power-generating plants have the potential to increase capacity and improve thermal efficiency through the use of waste heat recovery systems and bottoming cycles. Similar to bottoming cycles, APR for H₂ enrichment increases the efficiency of an engine or turbine, however, APR does not increase the capacity of the plant, and therefore these technologies are not analogous pieces of equipment.

Emissions Reductions

Nitrogen oxides (NO_x) emissions have many detrimental environmental and health consequences (US EPA, 1997; 1999). Accordingly, California's state government and the United States' federal government have set regulations for acceptable air quality and NO_x emissions (Cambridge et al. 2009).

Uncontrolled NO_x

Uncontrolled NO_x is defined as the NO_x emissions from a natural gas engine or turbine before any after-treatment of the exhaust gas.

According to the US EPA (1998), NO_x is produced during combustion through three different mechanisms. First, thermal NO_x can be produced in high concentrations when diatomic nitrogen is heated to 1573 K or more in the presence of oxygen. Second, fuel NO_x is produced from nitrogen in the fuel molecules. Fuel NO_x is therefore a greater concern for coal fired power plants than natural gas. Third, prompt NO_x is generated after atmospheric nitrogen combines with fuel molecules and is oxidized in the combustion process.

Engines

According to a report by Smutzer (2006), uncontrolled engines operating at stoichiometric air-fuel ratios can have NO_x emissions up to 10.7 g/kWh or 400 ppm at 10% O₂. However, in an engine with a prechamber operated in a lean burn condition with

an air-fuel ratio of 2 and no after treatment, NO_x production could be reduced to 0.536 g/kWh, or 27ppm demonstrating that NO_x production is reduced with leaner fuel air mixtures. Further research found that an ultra-lean burn engine with H₂ enrichment is capable of achieving emissions as low as 0.043 g/kWh or 3.45 ppm (Smutzer 2006). Uncontrolled NO_x emissions from a 23 MW Wartsila gas engine power plant is 1.33 g/kWh “based on generator terminal output” (Strandberg 2003).

Turbines

Without any reduction technology gas turbines generally emit NO_x of between 180-400 ppm depending on load and turbine type (Alne 2007), or 134-430 ppm according to Onsite Sycom Energy Corporation (1999). A breakdown of the turbine make, model, capacity, and associated NO_x emissions is shown in Table 2.

Table 2. Uncontrolled NO_x emissions of a variety of gas turbine makes and models (Onsite Sycom Energy Corporation 1999).

Turbine Make and Model	Allison 501-KB7	Solar Centaur 50	Solar Taurus 60	GE LM2500	GE Frame 7FA
Capacity (MW)	4.9	4.0	5.2	22.7	169.9
Uncontrolled NO_x (ppmv)	155	134	143	174	210
Uncontrolled NO_x (g/kWh)	3.57	3.02	2.92	2.92	3.62

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an effective after-treatment to reduce NO_x emissions by reacting NO_x with ammonia over a catalyst to convert it into harmless

atmospheric nitrogen and water. Most commonly, the catalyst is vanadium pentoxide (V_2O_5) on a titanium dioxide (TiO_2) support and reacts at temperatures around 570K - 670K. However, zeolite-type catalysts or titania-vanadium-tungsten are used at higher operating temperatures, up to 725K. SCR is a proven technology and has been used with coal and oil fired boilers, engines and turbines since the late 1970s (Jensen-Holm and Lindenhoff 2008).

SCR for Engines

Wartsila, the leading manufacturer of heavy duty power producing and marine engines, also offers a NO_x emissions control technology that incorporates selective catalytic reduction. Wartsila calls this option their Ultra Low NO_x Emissions or (ULE) and boasts NO_x reduction capabilities achieving stack emissions as low as 0.082-0.125 g/kWh or 5-9ppmv at 15% O_2 , or a 93.6-90.4% reduction (Strandberg 2003). Smutzer (2006) found that SCR could reduce NO_x emissions to a range between 0.067-0.20 g/kWh or 3.8-5.7 ppm at 10% O_2 .

SCR for Gas Turbines

According to the San Joaquin Valley Air Pollution Control District (SJVAPCD 2001) the best available control technology for NO_x after treatment in gas turbines is an SCR system that can reduce one-hour averages of NO_x to 2.5 ppmvd at 15% O_2 . Similarly, Amar et al. (2000) reports that gas turbines fitted with SCR units are capable of achieving 2 ppm NO_x starting from uncontrolled levels ranging from 110 to 167 ppmvd at 15% O_2 .

Gas turbines are often constructed in series with a bottoming cycle to improve efficiency. Such systems recuperate heat and therefore have cooler exhaust temperatures. However, simple cycle turbines reject high temperature exhaust gas and therefore must have special high temperature SCR equipment, which according to Termaath et al. (2006), costs about 6% more than conventional low temperature exhaust treatment. The cost comparison of high temperature versus conventional SCR can be seen in Figure 2. For the following analysis, high temperature SCR will be applied.

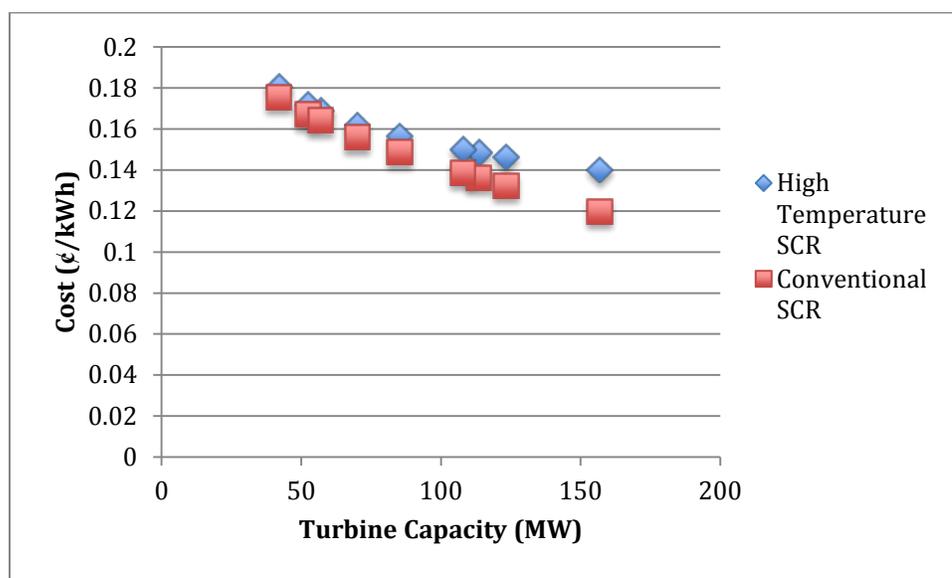


Figure 2. Cost of high temperature and conventional SCR NO_x reduction from mid-sized gas turbines in 2013 cents per kilowatt hour according to data provided by Termaath et al. (2006) to reach 15ppm NO_x emissions at 15% O₂.

Applicable Existing Regulations

Today the state of California and increasingly more government entities are more strictly regulating emissions levels and concentrations of pollutants in ambient air within their

respective jurisdictions. This analysis investigates the legislation regarding the two pollutant emissions of NO_x, as well as CO₂e as a GHG.

Standards and NO_x Emissions Reduction Credits

The California Clean Air Act requires regional air quality management districts or air pollution control districts to adopt a New Source Review program to ensure that new and modified stationary emission sources produce no net increase in emissions. To do so, all new or expanded gas-fired power generating stations must implement the Best Available Control Technology (BACT) to reach minimum emissions. With the guidance of the Air Resources Board, specific BACT limits will be determined by the different air pollution control districts. Any remaining emissions from a new source after BACT must be offset by add-on control technologies to reduce net emissions by an equivalent amount at an existing source (CARB 2004).

The state has also enforced the development of an emissions reduction credit (ERC) banking program to efficiently trade the emissions on the open market. Emission reduction credits (ERCs) are awarded to those who are able to cut emissions below the limits set by the regional air pollution control district. ERCs can be saved for later use, applied to new projects, or sold to other emitters (CARB 2013₂).

Health and Safety Code Section 40709 requires air pollution control districts to collect cost information of ERCs. The greatest number of NO_x ERC transactions, 45, occurred in

the San Joaquin Valley Air Pollution Control District (SJVAPCD) in 2012. The average price of NO_x in SJVAPCD in 2013 was \$51,038/ton. Across the state, however, the lowest average annual price was in Placer County at \$14,000/ton while the highest was \$115,000/ton in Santa Barbara (CARB 2013₂). Historically, the average cost of a ton of NO_x in SJAPCD since 2000 was \$37,991 and since 2008, the average cost per ton of NO_x has increased to \$54,584, all values adjusted to 2013 dollars using the Consumer Price Index (Anderson 2014).

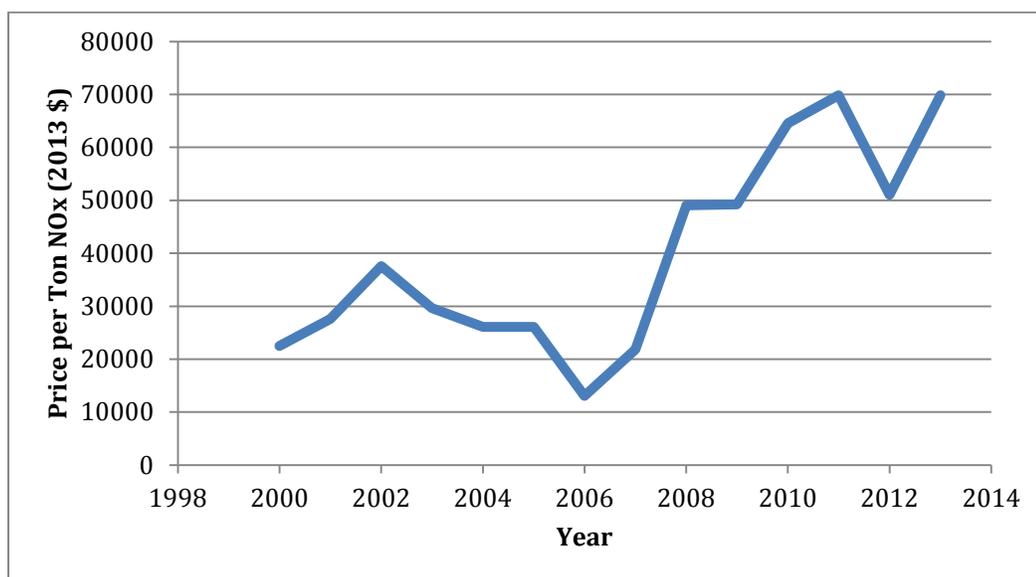


Figure 3. Average cost of NO_x in SJVAPCD over the last decade, and adjusted for 2013 dollars (Anderson 2014).

Engines

The San Joaquin Valley Air Pollution Control District has set maximum NO_x emissions levels for internal combustion engines over 25 brake horse power to 11ppmvd at 15% O₂. Currently, 25% of engines must be in full compliance with this regulation, and by

January 1st, 2017 100% of engines that fit this description must reach these levels (San Joaquin Valley 2013₁).

Turbines

Natural gas turbines are held to an even stricter standard than those of internal combustion engines. As of 2012, gas turbines greater than 10 MW must comply with emissions limits of 5ppmvd NO_x values at 15% O₂ (San Joaquin Valley 2013₂).

Low-Carbon and Renewable Energy Incentives

In an attempt to reduce GHG emissions to mitigate global climate change, California continues to incentivize the use of low-carbon and renewable energy resources. One of which is a feed-in-tariff for the production of renewably derived electricity, and the other is a cap-and-trade program for CO₂.

Feed-in-Tariff – Renewable Market Adjustment Tariff (ReMAT)

The value of renewable electricity in comparison to conventionally produced electricity was calculated as the difference between the market price referent (MPR) and California's feed-in tariff (FIT) for renewably produced electric power, Renewable Market Adjusting Tariff (Re-MAT). The MPR represents the average cost of current fossil-fuel powered electricity production including the capital, operating, and fuel costs of a 500MW combined-cycle gas turbine per kilowatt-hour of electricity generated and were applied to the development of the Renewable Portfolio Standard. In general, the

MPR represents the average cost of current fossil fuel energy production. These values have been calculated for various contract dates and lengths (PUC 2011). Re-MAT values, on the other hand, are set based on November 2011's Renewable Auction Mechanism and are subject to change based on participation (DSIRE, 2012). The difference between the MPR and Re-MAT represents the additional value of electricity produced by renewable products. While APR for H₂ enrichment does meet the end goal of the Re-MAT program, as the current regulations read, it is not officially eligible for this Re-MAT (DSIRE 2012). However, if the technology were to come to scale, there is no reason it would be omitted from renewable status on ReMAT. Therefore, for this analysis, it will be considered eligible as this approach appears to be the best method by which to evaluate the marginal increase in the value of renewably derived electricity.

Cap-and -Trade

Cap and trade is a market-based mechanism implemented by the state of California to help limit GHG emissions. In this way, California hopes to minimize the compliance costs associated with achieving its goal of 1990 GHG emission levels by 2020 as outlined in Assembly Bill 32 (CARB 2006). Under this regulatory structure, California's Air Resources Board (CARB) has set a limit on the state's total annual GHG emissions from CA's most emitting industries including: electricity suppliers, industrial sources, and providers of fossil fuel. These industries are given a set number allowances by the state, and if they exceed these emission levels, they must purchase additional allowances at auction or directly from a regulated entity with extra allowances. On the other hand, if an

industry emits fewer than the limit imposed on them, they are free to sell their unused allowances to industries that have exceeded their own emissions allowances (CARB 2014₁).

To achieve substantive reductions over time, the state will decrease the cap annually by about 3%. More specifically, CARB has allocated proportions of this total cap to different industries, thus granting them a set number of allowances. However, the allowances that are not given away for free, or those saved and consigned by utilities, are auctioned by the state four times a year. A floor is set of \$11.34/tonne of CO₂e on the auction prices to avoid a price collapse such as that experienced by the European Union Emissions Trading system in 2006 (Hsia-Kiung et al. 2014; Brown et al. 2012). In 2013, the daily average was \$13.57/tonne of CO₂e, but as of November 13th, 2014, the price was listed at \$12.15/tonne of CO₂e according to California Carbon Dashboard (Climate Policy Initiative 2014).

Any power producing entity that emits 25,000 or more metric tons of CO₂e annually is subject to comply with Cap-and-Trade allocations (CARB 2013₁). Additionally, with the start of the second compliance period on January 1st, 2015, CA's cap-and-trade program will expand to include the distributors of transportation fuels and natural gas (Hsia-Kiung et al. 2014).

While APR for H₂ enrichment is currently not regulated under CA's laws, other

renewable fuels, such as ethanol, which demands a functionally equivalent feedstock are eligible in CA. (CARB 2013₁).

METHODS

Chemical reaction waste heat recovery via aqueous phase reformation is a nascent technology that has not yet been scaled up to operational size. To explore the viability of this system, a techno-economic analysis was conducted of value of the benefits of APR for hydrogen enrichment for natural gas engines and turbines. In this analysis, cost savings were applied for the reduced natural gas demand, displaced need for emission control technology, and the value of renewably derived power and CO₂ and NO_x emissions savings, in accordance with California regulatory structures.

To conduct this analysis, a number of standardizing assumptions were made to ensure consistency and comparability throughout the analysis. First, the biologically derived feedstock of APR is assumed to be carbon neutral. Second, the addition of hydrogen to both the engine and turbine was set at 30% by volume in the natural gas fuel stream. The composition of the evolved gases from APR by energy content is assumed to be 50% H₂ and 50% a combination of CO and low weight alkanes (Cortright et al 2002; Vernon 2014). This translates to a total of 21% of the fuel energy demand for the engine or turbine being met by the hydrogen rich gases from APR. From here, energy balances, efficiency improvements, NO_x reductions, and GHG reductions can all be calculated and converted to a dollar value. To normalize the data in order for it to be summed, the metric, cents per kilowatt-hour (¢/kWh) of electricity produced, was chosen to evaluate the total value of the benefits. While the average capacity factor

(CF) of natural gas internal combustion engines in 2013 was 21.5% (1884.7 hours/year), and the average simple cycle natural gas turbines operate at a CF of only 4.1% (359.4 hours/year) (US EIA 2014₂), a much higher value was selected for this analysis. Many resources justify the selection of a higher CF. For example US EIA (2013) describes that while the national average turbine CF is quite low, in other regions of the country, including the Northeast, it is much higher, around 19%. Additionally, a variety of academic and industry resources apply CFs of 91.3% for both natural gas engines and turbines including a review of turbines NO_x reduction techniques from Termaath (2006), as well as industry analyses of turbines and engines (Onsite Sycom 1999 and Strandberg 2003). Additionally, it is believed that APR for H₂ enrichment is more likely to be applied to a generator with high a CF. Therefore this analysis will use a CF of 85.6% (7500 hours/year). Finally, when considering power plant equipment, an interest rate on debt of 8% was selected because it is a representative average of the industry (Bozzuto 2006; IEA and NEA 2010).

The emissions regulating market structures in California for NO_x and CO₂ were also considered for the APR for H₂ enrichment system and the value was quantified on a per kilowatt-hour basis. The sum of the avoided costs of fuel and emissions reduction technology, as well as the added value of emissions improvements represent the total value of the APR for H₂ enrichment system. This estimate provides the cash flow of an APR for hydrogen enrichment system when integrated with a natural gas engine or turbine. In other words, this analysis will generate the value per kWh generated and

then convert this value into a present value estimate to represent the ceiling present cost under which the system must fall in order to be economically viable. The cumulative cost of achieving the benefits of APR for hydrogen enrichment through this combination of avoided operation and installation costs, as well as added value from regulatory markets, will aid in the decision-making regarding research and development of aqueous phase reformation.

DISPLACED NATURAL GAS

Natural gas is displaced at a power generating facility installed with APR for hydrogen enrichment through two mechanisms. First, H₂ enrichment improves thermal efficiency thereby reducing the required chemical energy input of natural gas engines and turbines. Second, natural gas energy is directly displaced with the product gas of APR produced from a biologically derived feedstock. Through these two mechanisms the mass and cost of displaced natural gas is calculated below.

Efficiency Improvements

Efficiency gains in natural gas engines and turbines occur through two different mechanisms. The first is due to the endothermic waste heat recovery reaction, which is able to convert 1 joule of feedstock into roughly 1.05 joules of combustible gases, including H₂, CO, CH₄ and other low weight alkanes (Severy 2013). The overall

thermal efficiency changes for natural gas engines and turbines can be calculated using the following equations:

Equation 4.
$$Eff_S = \frac{P}{MW_{fuel}}$$

Equation 5.
$$Eff_{TCR} = \frac{P}{MW_{fuel} - MW_{recuperated}}$$

Equation 6.
$$MW_{recuperated} = (MW_{fuel} * \% MW_{biomass}) * \% E_{increase\ TCR}$$

Equation 7.
$$Eff_{H2} = Eff_{TCR} * (1 + \% Eff_{increase\ H2\ enrichment})$$

Where:

P = Capacity of power generating unit

MW_{fuel} = Necessary fuel to achieve desired power output

$MW_{recuperated}$ = Total chemical energy converted from waste heat

$\% MW_{biomass}$ = Percent of chemical energy in displacing natural gas

$\% E_{increase\ TCR}$ = Percent increase of biomass chemical energy as a result of the endothermic reformation reaction

Eff_{H2} = Efficiency of engine or turbine after TCR for H₂ enrichment

$\% Eff_{increase\ H2\ enrichment}$ = Efficiency increase from H₂ enrichment

Working backwards from the 21% of the fuel energy that APR produced gases contribute to the engine or turbine, 5% of that, or 1.1% of the total fuel demand is recuperated from the waste heat of the engine or turbine through the endothermic reaction of APR.

The second efficiency gain is a function of the benefits of H₂ enrichment on combustion properties in the prime mover. In natural gas engines, there are significant efficiency improvements from hydrogen enrichment on the order of 10% (Akansu et al. 2004; Swain et al. 1993). Turbines do not respond as positively, but because H₂ enrichment enhances combustion completeness to near 100%, there may be small improvements in turbine efficiency of 1% (Anderson 1975).

Using the assumptions discussed above, APR and H₂ enrichment combine to improve the overall thermal efficiency of a natural gas engine by 11% and the efficiency of a natural gas turbine by about 2.0%.

The efficiency gains due to hydrogen enrichment were taken from literature values and used to calculate the $Ef f_{TCR}$ from the standard efficiency. In engines, literature suggests a 10% increase in efficiency, while in turbines this value is much lower, on the order of a 1% increase, as a result of more complete combustion. Therefore, the efficiency of the engine or turbine integrated with the APR for hydrogen enrichment system was calculated using Equations 5-7.

Biologically Derived Fuel

In this analysis, a 30% by volume, in NG, H₂ enrichment value was selected because numerous groups tested various natural gas internal combustion engines using this concentration of hydrogen enrichment with the efficiency and emissions benefits

discussed above. At 30% by volume, roughly 10.5% of the total fuel energy into the system is from hydrogen. Assuming a 1:1 ratio of energy in hydrogen and the other evolved combustible gases, the amount of total energy from the reformed biologically derived fuel input is about 21% of the total fuel chemical energy delivered to the combustion process. The quantity of NG displaced by the input bio-derived feedstock through TCR for H₂ enrichment is calculated using the following equation:

Equation 8.

$$NG_{Displaced} = \left(\left(\frac{P}{Eff_{NG}} \right) - \left(\left(\frac{P}{Eff_{H2}} \right) * (1 - Bio_{Fraction}) \right) \right) * (CF)$$

Where:

$NG_{Displaced}$ = Amount of NG not needed when APR for H₂ enrichment is employed relative to the standard generation system

P = Rated electrical power output (MWelec)

Eff_{NG} = Initial engine or turbine efficiency with pure NG (unitless fraction)

Eff_{H2} = Engine or turbine efficiency with the improvements of TCR using APR for H₂ enrichment (unitless fraction)

$Bio_{fraction}$ = The non-NG portion of the fuel energy (unitless fraction)

CF = capacity factor of power plant

Equation 9. $Value\ of\ NG_{Displaced} = NG_{Displaced} * Cost\ of\ NG$

To financially quantify the displacement of natural gas and the associated efficiency gains of APR for hydrogen enrichment, the average 2013 cost of natural gas in the electricity industry was \$4.91/1000 ft³ and will therefore be applied to the value of displaced natural gas savings per kWh of power. However, there is considerable

variation in these costs (Figure 4). Over the last 10 years, natural gas has averaged \$5.90/1000 ft³ with a low of \$2.81/1000 ft³ in April, 2012 and a high of \$12.41/1000 ft³ in June, 2008 (EIA 2014₅).

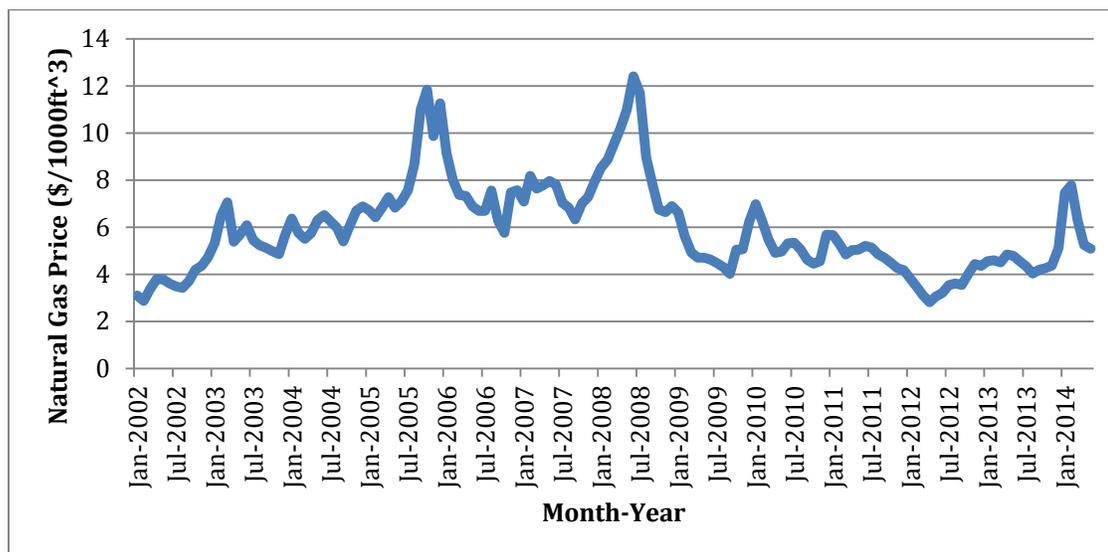


Figure 4. Prices of natural gas in the US power industry in dollars per thousand cubic feet from 2002 to 2014 (US EIA 2014₅).

Efficiency gains from both thermochemical recuperation and hydrogen enrichment reduce the amount of fuel needed to produce the same amount of electricity. Similarly, the efficiency improvement also reduces the quantity of emissions per kWh produced. However, this reduction is often insufficient to achieve emission levels mandated by state and federal agencies.

REDUCED NO_x

Hydrogen enrichment has the ability to significantly reduce NO_x emissions from a natural gas engine or turbine (Clayton 1976; Sierens and Rosseel 2000; Schefer 2003).

Hydrogen enrichment allows ultra-lean combustion thus reducing the combustion temperatures and, in turn, reducing thermal NO_x production. In engines, hydrogen enrichment is capable of reducing NO_x to 4ppmv (Smutzer 2006; Wilson 2012), while in turbines, the concentration can be reduced to 2ppmv (Termaath 2006).

Selective Catalytic Reduction (SCR)

Today, selective catalytic reduction (SCR) is the technique most commonly used to reduce NO_x emissions from natural gas engines and turbines. Thus, in this analysis, the normalized cost of SCR in ¢/kWh is quantified as an avoided cost and therefore another benefit of APR for hydrogen enrichment. SCR costs include both capital and operation and maintenance (O&M) costs, which includes the continual purchase of ammonia, as well as catalyst replacements. It should also be noted that other reduction technologies do exist, such as steam injection, but SCR was only considered here because it is the most common.

Engines

Gas engine NO_x reductions were analyzed using data provided by Strandberg (2003) at Wärtsilä. Specifications were provided for an SCR system integrated with a 23MW gas engine power plant to reduce NO_x by 90% equivalent to about 0.13 g/kWh, a final

exhaust stack concentration of 9.5ppmv on a 15% oxygen dry gas basis. The terms and assumed values for this economic analysis have been adopted from a number of sources. In order to view the cost of NO_x in real 2013 US dollars, a conversion factor from Euros to US Dollars was adopted from Shams (2005) (Equation 10.) and then the consumer price index (CPI) has been applied to include the rate of inflation over the past 10 years (US Inflation Calculator 2014) (Equation 11).

Equation 10.
$$\text{Euros} * \text{Dollar/Euro} = \text{Dollars}$$

Where:

$$\text{Dollar/Euro} = \text{conversion factor provided by Shams (2005)}$$

Equation 11.
$$\text{NPV}_{2003} * \text{CPI}_{2013}/\text{CPI}_{2003} = \text{NPV}_{2013}$$

Where:

NPV_{2003} = Net present value of SCR levelized per kWh electricity

NPV_{2013} = Net present value of SCR levelized per kWh electricity

CPI_{2003} = Consumer price index in 2003

CPI_{2013} = Consumer price index in 2013

Other inputs necessary in calculating the displaced cost of emissions reduction equipment include an O&M cost of 1.5% cost of investment, 5-year catalyst lifetime (Strandberg 2003), a capacity factor of 85.6%, a discount rate of 8% (Bozzuto 2006; IEA and NEA 2010), and a system lifetime of 20 years for power, emission reductions, and APR equipment (US EPA 2000₃).

Equations 10 and 11 describe the calculations to assess the annualized cost of SCR per electricity generated, respectively. This value in ¢/kWh represents the avoided cost of NO_x controls if APR for hydrogen enrichment were implemented instead. Still, the emissions from exhaust treated with SCR are higher than those from a system enriched with hydrogen. Therefore, in the following section, the additional reduction in emissions will be assigned a value according to California Emissions Reduction Credits program.

Equation 12.
$$A = P * \left(\frac{i*(1+i)^n}{(1+i)^n - 1} \right)$$

Equation 13.
$$\frac{(A+O\&M)}{G} = LCOE$$

Where:

A = Annual Amount

P = Present Worth

i = Effective Interest Rate

n = Time

O&M = Annual Operation and Maintenance Costs

G = Annual Power Generation

LCON = Levelized Cost of NO_x reduction per kWh electricity

Turbines

Termaath et al. (2006) has provided a thorough analysis of NO_x reduction techniques for mid-sized (30-150MW) gas turbines and has provided the average costs of SCR levelized per unit of electricity produced in 2006 US\$/kWh using Equations 12 and 13. While Termaath analyzed a variety of reduction technologies, only the high temperature SCR

values have been applied in this model as it corresponds to a high temperature exhaust stream of 800-1100F. This system was analyzed using CF of 85.6%, or 7500 hours per year. Termaath's figures, which were presented in net present value (NPV) for 2006 dollars have been converted to NPV 2013 dollars using the CPI and Equation 11.

Emissions Reduction Credits

The San Joaquin Valley Air Pollution Control District (SJVAPCD) traded a large portion of NO_x in California in 2012 (CARB 2013₂) and has therefore been chosen as a representative sample for the calculation of the value derived from NO_x reduction through CA's regulatory mechanisms. The NO_x emissions price of \$51,038 per ton, in 2013 dollars, in the SJVAPCD in 2012 (CARB 2013₂) was used to determine the value of APR for hydrogen enrichment with regard to reducing NO_x below obligatory levels for gas engines and turbines, Equations 14 and 15.

$$\text{Equation 14.} \quad \text{Tradable } NO_x = \left(NO_{x_{regulation/SCR Limits}} - NO_{x_{H_2 Enrichment}} \right)$$

$$\text{Equation 15.} \quad \text{Value of Tradable } NO_x = (\text{Tradable } NO_x * ERC)$$

Where:

$\text{Tradable } NO_x$ = Mass of NO_x per kWh reduced below regulatory levels
 $NO_{x_{regulation/SCR Limits}}$ = Emissions level enforced by air quality control district, or levels achieved by SCR, whichever is lower
 $NO_{x_{H_2 Enrichment}}$ = Emissions level achievable by H₂ enrichment
 $\text{Value of } H_2 \text{ Enrichment}$ = Value of tradable NO_x per kWh
 ERC = Average price per ton of NO_x traded in the SJVAPCD

For this analysis, an addition of 30% H₂ by volume will reduce NO_x levels to 4ppmvd. This value was chosen because it falls near experimental results of Smutzer (2006) and Wilson (2012) of 4ppmvd. Regulations for similar sized engines within the SJVAPCD must comply with emissions levels of 11ppmvd. However, because SCR is able to achieve limits below those set by the SJVAPCD, engines using this technology qualify for emission reduction credits. Therefore, the marginal increase in ERCs was calculated to find the added value of APR for H₂ enrichment.

RENEWABLY DERIVED ELECTRICITY

APR for hydrogen enrichment produces renewably derived electricity by displacing a portion of the natural gas power plant's fuel with a hydrogen rich gas produced from biologically derived feedstocks. Like other biomass energies, California recognizes that the use of bioenergy can help reduce the state's GHG emissions. Biologically derived fuels also represent a renewable source of energy that can be produced locally in many regions of the state bolstering the economy and energy security (Germain and Katofsky 2006).

Feed-in-Tariff

For this analysis, the value of biomass-derived renewable electricity in comparison to conventionally produced electricity was calculated as the difference between the MPR and California's feed-in tariff, Re-MAT. The MPR varies by the year and the length of

contract signed, for this analysis, a 10-year contract signed in 2013 was used as it is a conservatively low estimate of the price power producers will earn in the future (PUC, 2011). The Re-MAT value is also subject to change as a function of participation from the biomass-to-energy industry. If less than half of the desired capacity is met in the first two months, the price will increase by \$4/MWh in the third and fourth month. After that, if there is still too little interest, the price will increase every two months until 50% of participation is met. Conversely, if participation is too high, prices can decrease during those two-month intervals (DSIRE 2012).

However, because APR for hydrogen enrichment uses a mix of fossil fuel and renewable biomass fuel, only the fraction of electricity produced from the chemical energy derived from biomass is eligible for this feed-in-tariff. Assuming 30% addition of hydrogen by volume to the natural gas fuel stream and assuming that the evolved gas contains equal parts H₂ as well as CO and other alkanes on an energy basis, then 21% of the chemical energy input to the system will be biologically derived. Therefore, Re-MAT prices apply to 21% of the total electricity generated, Equation 14.

Equation 16.

$$\text{Value of Bio Derived Power} = (\text{ReMAT} - \text{MPR}) * \text{Fraction of Bio Derived Fuel}$$

Where:

Value of Bio Derived Power = Value of bio derived power per kWh generated

ReMAT = Feed-in-Tariff price per kWh for biologically derived power

MPR = Average price per kWh for a natural gas combined cycle power plant

Fraction of Bio Derived Fuel = Fraction of fuel derived from biomass

Cap-and-Trade

In California, cap-and-trade has been implemented to create a market force to reduce GHG emissions. While this program regulates emissions from a wide range of industries, it also has authority over state electricity generation and will therefore be applied to APR for hydrogen enrichment.

To determine the reduction in CO₂ emissions as a result of APR for hydrogen enrichment, a set of standardizing assumptions were made with regard to the natural gas engine or turbine. First, the addition of H₂ to the fuel stream was assigned to a concentration of 30% by volume as this value has been thoroughly tested, and proven to achieve the aforementioned benefits of H₂ enrichment. Second, to assist in the calculations of CO₂ savings the specifications of a Wartsila 23 MW simple cycle, natural gas engine with a thermal efficiency of 49% was applied. APR for hydrogen enrichment can increase the overall thermal efficiency of an engine from 49% to 54%, through endothermic, thermochemical recuperation and improved combustion characteristics within the engine cylinders. Similarly, a typical 100 MW turbine with an initial simple-cycle efficiency of 40% was used and through APR for H₂ enrichment, efficiency increased to 41%. The engine and turbine were assigned a capacity factor of 85.6%. Finally, to determine the actual carbon savings from the bio-derived fuel input displacement of natural gas and efficiency gains reducing the consumption of natural gas,

a conversion factor provided by the US EPA (2014) states that one therm of natural gas emits 0.005302 metric tons of CO₂e, and the avoided CO₂e emissions will be derived using this value and the calculated displaced natural gas from the APR for hydrogen enrichment system. The total CO₂ offset by APR for H₂ enrichment is calculated using the efficiency and capacities of power generating equipment for engines and gas turbines (Equation 7).

Equation 17.

$$C\&T\ Value = (Displaced\ NG\ per\ kWh * CO_2e\ of\ NG * MP\ of\ CO_2e)$$

Where:

C&T Value = Cap & Trade value of CO₂e savings per kWh generated

CO₂e of NG = Mass of CO₂e emissions from NG

MP of CO₂e = Value of permit to emit one tonne of CO₂e

Under California's Cap-and-Trade program, each tonne of CO₂e abated represents either an added revenue stream or an avoided cost for an electricity generating entity, depending on whether the power generating facility has emitted the total allocated amount.

Additionally, California has set a lower limit, or "floor price", at \$11.34/tonne for 2014 (Hsia-Kiung et al. 2014) with a 2013 average market price is of \$13.57 (Climate Policy Initiative 2014).

Future and Present Value of APR for H₂ Enrichment

To give more meaning to the value of APR per kWh generated, a present value of the APR for hydrogen enrichment system was calculated using Equations 18 and 19.

Equation 18.
$$A = V_{APR} * EG$$

Where:

V_{APR} = Value of APR per electricity generated

EG = Electricity generated per year

A = Annual Amount

The present value was calculated from the annual value of APR for H₂ enrichment using Equation 20.

Equation 19.
$$P = A * \left(\frac{(1+i)^n - 1}{i * (1+i)^n} \right)$$

Where:

P = Present Value

A = Annual Amount

i = Effective Interest Rate

n = Time

RESULTS

In the following section, the value of each the aforementioned benefits of APR for hydrogen enrichment has been adjusted to 2013 US cents per kilowatt-hour (¢/kWh) of electricity produced.

DISPLACED FOSSIL NATURAL GAS

Engines and turbines respond to APR for H_2 enrichment to different extents. Engines can experience an increase in thermal efficiency of about 11%, while turbines increase by 2.0%. For both, there is a proportional savings of natural gas, which cost the power producing companies an average of $\$4.51/1000 \text{ ft}^3$ in 2013 (US EIA 2014₅). However, this price has considerable variation, which will be addressed in the Discussion.

Engines

In a natural gas engine, APR for hydrogen enrichment can displace natural gas demand by 30%. Much of this is the result of an 11% efficiency improvement from TCR by APR for H_2 enrichment, and the remainder is directly displaced with a renewably derived feedstock. In a 23MW capacity engine with an initial efficiency of 49% and a capacity factor of 85.6%, this corresponds to a reduction in consumption of 350,000 $1000 \text{ ft}^3/\text{year}$, or roughly $\$1.6$ million of natural gas costs. Per power produced, this saves the power generator 0.91 ¢/kWh in fossil fuel costs.

Turbines

In 100MW turbines with a baseline efficiency of 40%, the implementation of biologically derived fuel and the 2% increase in thermal efficiency from APR and hydrogen enrichment yields a 24% reduction of the natural gas demand. That is equivalent to 1,500,000 1000 ft³/year and at a 2013 electric power price average of \$4.51/1000 ft³ (US EIA 2014₅) this corresponds to \$6,600,000/year. On a per power produced basis, this saves the power generator 0.88 ¢/kWh in fossil fuel costs.

Table 3. Natural gas savings achieved by APR for H₂ enrichment of a natural gas engine and turbine, in 2013 dollars.

Prime Mover	NG Saved (1000 ft³/year)	Annual Value (\$/year)	Levelized Value (¢/kWh)
23MW Engine	350,000	1,600,000	0.91
100MW Turbine	1,500,000	6,600,000	0.88

NO_x REDUCTIONS

Reduced NO_x emissions are a valuable characteristic for any combustion process. To meet regulated emissions levels, control technologies such as selective catalytic reduction units are purchased, installed, and maintained on the exhaust stream of natural gas engines and turbines. Additionally, if an entity achieves emissions below mandated levels, then the difference can be sold as emissions reduction credits (ERCs) to other NO_x producing entities.

Selective Catalytic Reduction

To control NO_x emissions from natural gas engines and turbines, SCR is often added on the downstream end of the equipment. As with most equipment, there is both a capital cost and an O&M cost associated with SCR. However, these costs vary between the engine and turbine technology.

Engines

Gas engine NO_x reductions were analyzed using data provided by Wärtsilä (Strandberg 2003). Specifications were provided for an SCR system integrated with a 23MW gas engine power plant to reduce NO_x by 90% equivalent to about 0.13 g/kWh, or 9.5ppmv 15% oxygen dry gas. This level will comply with emissions regulations in many air districts, but will cost the power plant owner approximately 0.310 ¢/kWh for the NPV₂₀₁₃.

Turbines

Turbine control technology costs were adopted from Termaath et al. (2006). In Figure 5, SCR costs for nine different mid-sized turbines have been plotted to distinguish the average cost in NO_x reductions, as well as the variation in cost between equipment.

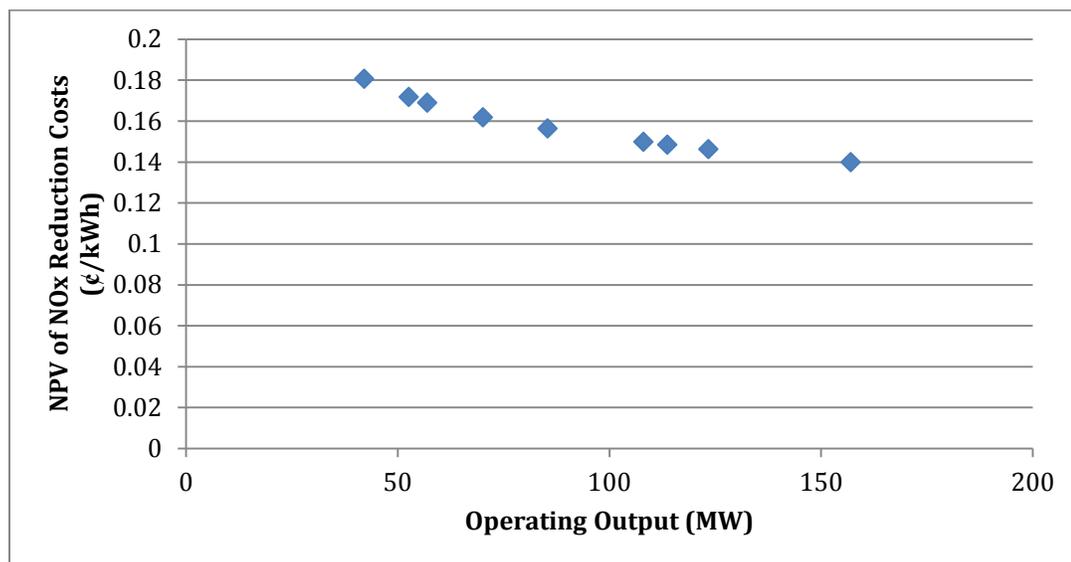


Figure 5. Cost of high temperature SCR NO_x reduction from mid-sized, simple cycle gas turbines in 2013 cents per kilowatt hour according to data provided by Termaath et al. (2006) to reach 15ppm NO_x emissions.

On average, high temperature SCR of 40-160MW turbines costs 0.158 ¢/kWh (Termaath et al. 2006).

Emissions Reduction Credits (ERCs)

APR for hydrogen enrichment has the potential to reduce NO_x levels below those mandated by different air quality districts of California. The difference in actual NO_x emissions and allowed NO_x emissions is then available for trade as an ERC. The price of ERCs varies across the state and from year to year. However, because the consistent activity of the ERC market in the SJVAPCD, its 2012 average has been applied in this analysis.

Engines

SCR and H₂ enrichment are capable of reducing NO_x levels to 7ppmv at 15% O₂ (Strandberg 2003) and 4ppmv at around 11% O₂ respectively (Smutzer 2006; Wilson 2012), both below the 11ppmv 15% O₂ dry gas basis (0.1465g/kWh) compliance levels in the SJVAPCD, and therefore would accrue emission reduction credits to be sold on the market. This analysis uses the 2012 average cost of a NO_x of \$51,038 per ton in 2013 dollars (CARB 2013₂). Other possibilities will be explored in the sensitivity analysis presented in the Discussion. The respective savings due to avoided NO_x reduction costs and value of ERCs have been linearly interpolated from Strandberg (2003) and are displayed in Table 4.

Table 4. Comparison of the value of ERCs earned by Ultra Low Emission (ULE) SCR Technology from Wartsila and hydrogen enriched engine.

	ULE SCR ₁ (9.5ppmv or 0.13g/kWh)	H ₂ Enrichment ₂ (4ppmv or 0.08g/kWh)	Marginal Decrease from SCR to H ₂ Enrichment
NO_x Reduced below Limit (Tradable)	3.1 tons/yr	14.3 tons/yr	11.1 tons/yr
Tradable NO_x Value:	160,000 \$/yr	730,000 \$/yr	570,000 \$/yr
Tradable NO_x Value	0.093 ¢/kWh	0.42 ¢/kWh	0.33 ¢/kWh

₁Strandberg 2013

₂Smutzer 2006; Wilson 2012

Turbines

Again, the value of ERCs has been applied from SJVAPCD 2012's average cost of NO_x. In this region, turbines greater than 10 MW, must comply with 5ppmvd NO_x values at 15% O₂ by 2017 (SJVAPCD 2013₂). In conjunction with the savings of displaced SCR and the added revenue from increased ERCs, the total value of NO_x reductions from the hydrogen enrichment as applied to turbines is summarized in Table 5 using a NO_x limit of 5 ppmv 15% oxygen dry gas basis (0.058944 g/kWh) (Termaath et al. 2006) and the 2012 NO_x cost of \$51,038 2013\$/ton (CARB 2013₂).

Table 5. Value of the ERCs earned by hydrogen enriched 100MW turbines in SJVAPCD.

NO_x Emissions with H₂	2ppmv
Average Cost of NO_x:	51,038 \$/ton
Annual Value of Tradable NO_x:	1,500,000 \$/year
Levelized NO_x Value:	0.20 ¢/kWh

It should also be noted that cost estimates for SCR systems capable of reducing NO_x to 4 and 2 ppm in engines and turbines, respectively, were not available in the literature. Therefore, a direct replacement was assumed of SCR by H₂ enrichment, and consequently, the displaced cost of SCR is a conservatively low estimate, as H₂ enrichment reduces NO_x levels well below those generally achieved through SCR. Table 6 shows the total value of NO_x emissions reductions through the summed values of a conservatively low displaced SCR cost along with the expected values of NO_x emissions credits.

Table 6. Total value of NO_x emissions reductions. Limits and value of NO_x emissions as set by SJVAPCD, SCR technology, and H₂ enrichment technology.

	SCR NO _x (ppm)	Cost of SCR (¢/kWh)	H ₂ NO _x (ppm)	SJVAPCD NO _x Limit (ppm)	ERC Value with H ₂ NO _x Beyond SCR (¢/kWh)	Total NO _x Value (¢/kWh)
Engine (23 MW)	9.5	0.31	4	11	0.33	0.64
Turbine (100 MW)	15	0.16	2	5	0.20	0.36

VALUE OF RENEWABLE ELECTRICITY

To mitigate GHG emissions, a variety of regulatory structures have been implemented to reflect the value California places on low carbon energy generation. These mechanisms use differing approaches, one to incentivize renewable energy generation via a feed-in-tariff for biomass energy and the other motivates reduced emissions by both discouraging emissions and encouraging reductions through a cap-and-trade program for CO₂.

Feed-in-Tariff

The ReMAT feed-in-tariff ensures a higher price for renewably derived electricity than the baseline fossil price MPR for a 10-year contract signed in 2013. This difference applied to the portion of renewable fuel used in the combustion process, via APR for H₂ enrichment, provides a marginal increase in value of roughly 0.17 ¢ /kWh (Table 7).

Table 7. Marginal difference in MPR (PUC 2011) and California's estimated Renewable Market Adjustment Tariff (DSIRE 2012) for all electricity generated from the plant.

MPR 2013	Re-MAT	Difference	Difference x 21%
8.103 ¢ /kWh	8.923 ¢ /kWh	0.820 ¢ /kWh	0.17 ¢ /kWh

Cap-and-Trade

Because APR for hydrogen enrichment utilizes a biologically derived feedstock, it is assumed to have net zero carbon emissions and its proportional contributions are exempt from compliance to California's cap-and-trade program. APR for hydrogen enrichment reduces the carbon intensity of the generated electricity by the use of renewable fuel, and also through the improved efficiency of the system. Together, these mechanisms reduce the GHG emissions from the H₂ enriched engine and turbine, thereby reducing the number of carbon credits consumed by the power generator. Additionally, under CA's Cap-and-Trade program, unused allowances can be sold to other entities through a carbon market creating financial incentives for electricity generators to cut carbon emissions. The average 2013 price of an allowance of \$13.57/tonne CO_{2e} was applied in this model (Climate Policy Initiative 2014).

The efficiency increase, in conjunction with the carbon neutrality of the feedstock reduces GHG emissions from this power producer by 30% for engines and 24% in turbines. These CO_{2e} savings are summarized in Table 8.

Table 8. Carbon-dioxide emissions savings from APR based H₂ enrichment for natural gas fuel engines and turbines operating with an 85.6% capacity factor.

Prime Mover	Capacity (MW)	CO₂ Reduction	Reduction (tons CO₂/year)	Annual Value (\$/year)	Levelized Value (¢/kWh)
Engine	23	30%	21,000	\$260,000	0.15
Turbine	100	24%	90,000	\$1,080,000	0.14

TOTAL VALUE

The value of all the benefits of APR for H₂ enrichment have been summed below, in Table 9, to represent the full economic value of this efficiency improving, pollution reducing, renewable energy technology. These values can also be seen in Figures 6 and 7.

Table 9. The total values of the APR H₂ enrichment system for a natural gas engine and turbine.

Benefit of APR	Value (¢/kWh)	
	Engine	Turbine
Displaced Natural Gas	0.91	0.88
Avoided SCR Costs	0.31	0.16
Emissions Reduction Credits	0.33	0.20
Feed-in-Tariff	0.17	0.17
Cap-and-Trade	0.15	0.14
Total	1.87	1.55

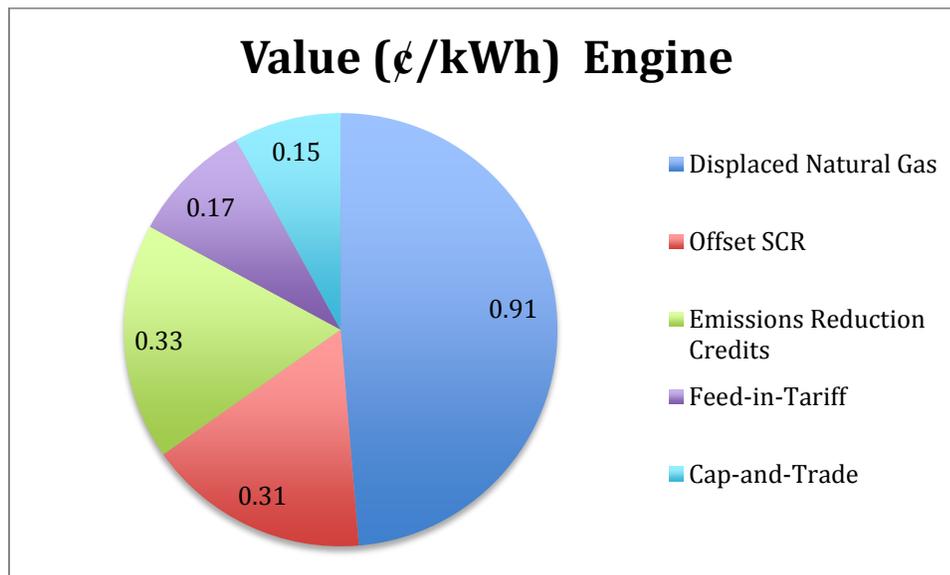


Figure 6. Total value of APR for H₂ enrichment in a natural gas engine in 2013 ¢/kWh.

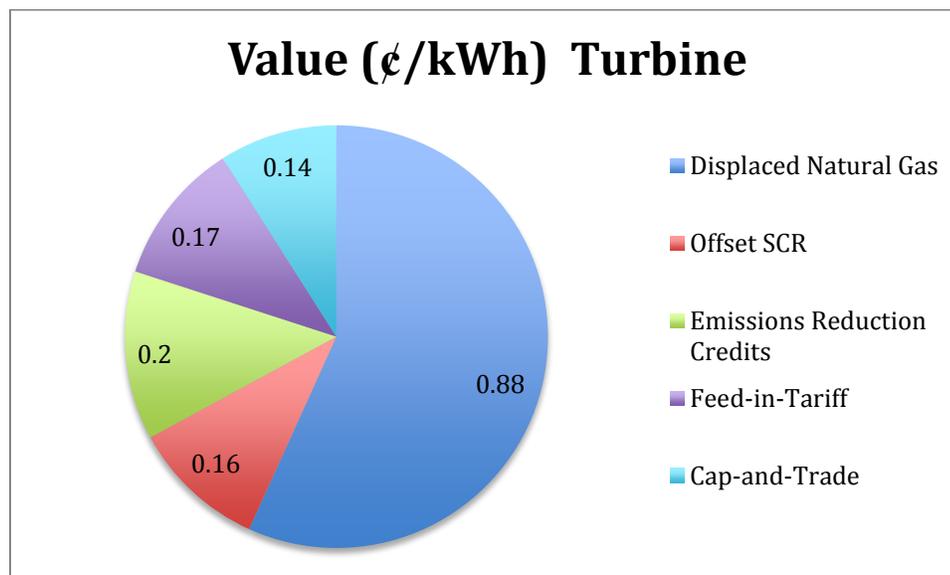


Figure 7. Total value of APR for H₂ enrichment in a natural gas turbine in 2013 ¢/kWh.

Over the course of the estimated 20-year lifetime with a CF of 85.6% and interest rate of 8%, APR for H₂ enrichment of a 23 MW engine would yield a present value of \$32 million. A 100 MW turbine with an integrated APR for H₂ enrichment system operated with the same lifetime and CF with an identical interest rate has a present value of \$115 million. These present value estimates provide a ceiling, or sort of benchmark, under which the present value of the capital and variable costs of the APR system for H₂ enrichment must fall in order to be economically feasible.

DISCUSSION

The value of APR for H₂ enrichment, as it applies to natural gas engines and turbines, is calculated above, but to be most effectively communicated, it must be viewed in the context of typical total cost to produce electricity or typical wholesale sales prices from the generator to the utility.

As considered above to determine the marginal increase in value of biomass derived electricity, the Market Price Referent is a benchmark used to compare the price of power generation to today's most typical generating system – a baseload combined cycle gas turbine power plant. While the cost varies by length and date of contract, the largest relative expense for this power generating system is that of natural gas over the course of its life (PUC 2011). A matrix of cost per kilowatt-hour, contract start date, and contract date are laid out in Figure 8.

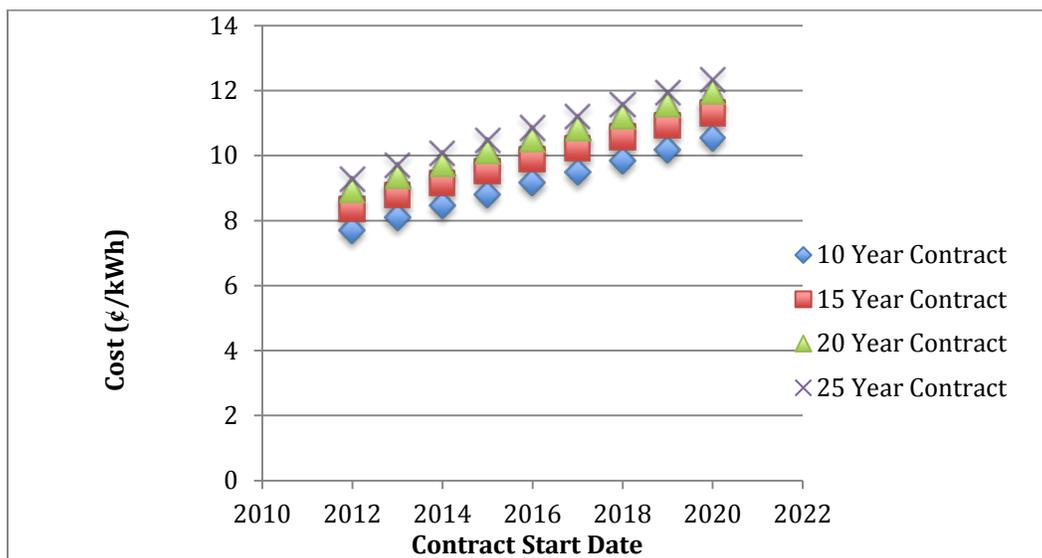


Figure 8. Adapted 2011 Market Price Referent values for long-term (10-25 year) RPS contracts in nominal ¢/kWh (PUC 2011).

At the highest end of the MPR of 12.326 ¢/kWh, the value of APR for H₂ enrichment is still significant, roughly, one-sixth of the overall value of electricity, while at the lower end of the MPR of 7.688 ¢/kWh, APR for H₂ enrichment represents about one-fourth of this value.

Another metric by which to compare the value of APR for H₂ enrichment is that of LCOE for different power generating technology. The US EIA (2014₃) has compiled such costs in 2012 dollars for plants entering service in 2019. According to this report the LCOE of a conventional combined cycle natural gas turbine is 6.63 ¢/kWh, which is less than current MPR, which starts at 8.454 ¢/kWh. Of this cost for a combined cycle natural gas turbine, 74% is due to the variable O&M costs, which are primarily a function of fuel

costs. The large influence of fuel costs suggest that efficiency improvements can have significant impacts on reducing overall costs.

As seen in the equations throughout the Methods section, many variables contribute to the total sum of the value of APR for H₂ enrichment of natural gas engines and turbines. Therefore, throughout the Discussion a sensitivity analysis will be conducted of many the respective drivers behind these costs. The Discussion will again break down the factors by their realized benefit in the order of Displaced Natural Gas and Waste Heat Recovery, NO_x Reductions, and the Value of Renewable Energy. The discussion will also provide additional considerations to each section, and finally, future recommendations regarding the research and development of APR for H₂ enrichment of natural gas engines and turbines.

DISPLACED NATURAL GAS AND WASTE HEAT RECOVERY

The APR for H₂ enrichment system as applied to natural gas engines and turbines displaces natural gas demand through two mechanisms. The most direct and that which displaces the greatest proportion of natural gas is the displacement by a biologically derived feedstock. For example, Severy (2013) produced a thermodynamic model of the APR process driven by a natural gas engine with high exhaust temperatures, and found that there was enough energy in the exhaust to replace 34% of the natural gas with H₂ rich reformat of glycerol. Furthermore, he found that using APR at higher pressures

could produce 100% of the fuel needed to drive a small 1 MW engine and up to 40% of the fuel needed to drive a larger 7 MW engine. In this analysis, only 21% of the initial natural gas chemical energy is replaced with biologically derived feedstock because this level is thought to provide the most benefits at the least expense. However, because natural gas savings are such a large portion of the value of APR for H₂ enrichment, the application of larger proportions of biologically derived may yield even larger savings.

The second mechanism behind natural gas displacement is the result of thermal efficiency improvements of the prime mover. These efficiency improvements are achieved via two pathways. The first is a result of waste heat recuperation, and the second is due to the beneficial combustion characteristics of hydrogen. In this way, 20% displacement of natural gas grows to 21%. The remaining displaced natural gas is the result of efficiency improvements through the favorable combustion properties of H₂ enrichment. In engines this effect can be very large, improving thermal efficiency by 10%, which overall contributes to reducing total natural gas use by 30%. However, in turbines, efficiency improvements from H₂ enrichment are only the result of increased combustion efficiency and therefore limited and have been estimated to be roughly 1%, yet overall a 24% reduction in natural gas use is realized in turbines from APR for H₂ enrichment. As the price of natural gas rises in the future, the value earned from its displacement will increase proportionally.

However, because APR is a nascent technology and has never been proved at a commercial scale, it is important to consider a range of its ability to increase chemical energy of the feedstock. For instance, if catalyst technology is improved and optimized for the ideal feedstock, a 10% increase in chemical energy is conceivable. Under this scenario, the value of displaced natural gas in engines would increase from 0.91 to 0.93 ¢/kWh. In turbines, it would also increase slightly from 0.88 to 0.91 ¢/kWh. This increase in efficiency would not significantly increase the value of CO₂e savings for engines, but turbines slightly gain value from 0.14 to 0.15 ¢/kWh. On the other hand, if the APR reaction were found to reduce the chemical energy of the feedstock, perhaps due to incomplete conversion of the feedstock then the value of APR for H₂ enrichment would decrease. A reduction in chemical energy of the feedstock of 5% would lead to a decrease in natural gas savings from 0.914 to 0.870 ¢/kWh for engines and from 0.881 to 0.823 ¢/kWh for turbines. Similarly, the value of CO₂ from Cap-and-Trade would decrease from 0.15 to 0.14 ¢/kWh for engines and from 0.14 to 0.13 ¢/kWh for turbines. In comparison to the total value of APR for H₂ enrichment, about 1.9 ¢/kWh for engines and 1.5 ¢/kWh for turbines, neither the change CO₂e nor natural gas savings constitute a significant change in the overall value.

Historically, the price of natural gas in the US has varied considerably (Figure 3). For example, low prices were experienced throughout the last 5 years as a result of increased domestic production (US EIA 2014₁), but in the first three months of 2014 costs spiked to \$7.14/1000 ft³ (US EIA 2014₅). In order to consider value of natural gas savings into the

future, a projection was taken from the US EIA's Annual Energy Outlook (2014₁), which predicts the cost of natural gas in 2040 to be \$7.98/1000 ft³ in 2013 dollars. Using the projected cost of natural gas in 2040, 1.6 ¢/kWh can be saved in fossil fuel costs when APR for hydrogen enrichment is applied.

Using the Henry Hub projected spot price, the US EIA (2014₁) has predicted the following price trends in 2013 dollars through 2040 (Table 10).

Table 10. Henry Hub Spot Price and corresponding value to APR for hydrogen enrichment due to natural gas displacement in 2013 dollars.

Year	2013	2018	2020	2025	2040
\$/1000 ft³	4.15	4.99	4.56	5.44	7.96
Engine (¢/kWh)	0.914	1.01	0.924	1.10	1.61
Turbine (¢/kWh)	0.881	0.974	0.890	1.06	1.55

Feedstock

The price of natural gas must also be assessed in parallel with the price of APR's biologically derived feedstock, the cost of which could have a significant impact on its economic feasibility. There are many possible choices for feedstock and the ideal source will be completely converted by APR reactions, have low carbon-intensity, and be in great supply at a low cost. In reality, however, the selection of feedstocks for APR will be an attempt to optimize for each of these characteristics. To help with this selection, a life cycle analysis of the entire APR for H₂ enrichment system to confirm that its installation

will yield a net CO₂e reduction. The feedstocks, which are biologically derived and potentially also waste products, are expected to drive this overall CO₂e reduction.

Additionally, the financial savings of the displaced natural gas will likely be offset by the cost of the biologically derived feedstock used in the reformation process, and therefore, the cost of this feedstock will need to be carefully analyzed. However, because there are many potential options for this feedstock, there is a chance of utilizing a waste stream of low or negative cost. Such an economic analysis is beyond the scope of this project because there are such a wide variety of viable feedstocks including waste glycerol from biodiesel production and sugars produced by the depolymerization of cellulosic feedstocks.

WASTE HEAT RECOVERY

Waste heat recovery is an attempt to recover usable energy from the thermal energy in the exhaust gases of a prime mover. The second law of thermodynamics requires even a perfectly reversible Carnot heat engine to reject a certain amount of energy in the form of heat in its exhaust stream. In real systems this energy often holds enough exergy to produce work and this waste stream can be harnessed through the addition of bottoming cycles.

Bottoming Cycles

Bottoming cycle power-producing devices can be a steam Rankine cycle, Organic Rankine cycle, or Kalina cycle. However, steam Rankine bottoming cycles are the most common and are the technology of focus here because their waste heat temperature requirements correspond with the temperatures provided by both the natural gas engine and turbine (BCS Incorporated 2008).

Because bottoming cycles require no fuel input, their operational costs are relatively low. However, the capital costs of bottoming cycles are quite high relative to the marginal increase in plant capacity they provide. For example, bottoming cycles have been found to have installed costs in the range of \$1900-2700 per additional kW installed (Waste Heat Recovery 2008; US EPA 2012; Shelledy 2013). This is significantly higher than the capital cost of the topping cycle. For Wartsila natural gas engines the capital cost is inversely related to the generating capacity, and range from \$800-1500/kW for a 450-9MW power plant, respectively (Shelledy, 2013). Natural gas turbines have lower capital cost between \$214/kW and \$715/kW for what the EPA refers to as large and small units, respectively (US EPA 2003).

This suggests that APR for H₂ enrichment may be able to compete with bottoming cycles on an economic basis. Therefore, if the power producer seeks increased efficiency, H₂ enrichment from APR may be an appropriate add-on, particularly for large engines whose

overall thermal efficiencies can be expected to increase by 12%. For engine applications, APR for H₂ enrichment and bottoming cycles can achieve similar increases in efficiency and can be compared directly. Wartsila's Flexicycle natural gas engines produce 9% of their total energy from the bottoming cycle (Shelledy 2013). In combined cycle turbines however, bottoming cycles can generate approximately 30% of the total power (Smith et al. 2001). It is important to note that these technologies are not identical tools even with similar improvements in efficiency in engines because bottoming cycles increase the system's capacity, while H₂ enrichment will not, and H₂ enrichment will reduce the quantity of criteria pollutant emissions and a bottoming cycle will not.

NO_x REDUCTIONS

NO_x emissions from large stationary sources are regulated federally. The state of California has implemented further regulations of this criteria pollutant, and California's air pollution districts have set varying emission limits. A banking system has also been established to use market techniques to help cut NO_x efficiently.

Selective Catalytic Reduction

SCR is an effective way to reduce NO_x to a very low level. However, SCR is not without its limitations and continued reduction of NO_x has its trade-offs with increased ammonia emissions due to ammonia slip (Gil 2013). High NO_x reduction demands also require a more frequent replacement of catalyst and more ammonia application increasing

operating cost. Eliminating SCR entirely and adopting hydrogen enrichment removes both the capital and operating costs of the system. However, SCR costs are subject to variations. One metric that is subject to change is the assumed discount rate used to amortize and calculate their cost in 2013 dollars. In the initial calculations an 8% interest rate on debt was used according to Bozzuto (2006) and IEA and NEA (2010). However, if a rate of 5% were used, it decreases the displaced cost from 0.31 to 0.29 ¢/kWh for engines, and from 0.16 to 0.15 ¢/kWh for turbines. Conversely, if a higher interest rate of 10% is applied, the value of displacing SCR from engines increase to 0.33 ¢/kWh and to 0.17 ¢/kWh for turbines.

SCR of engines is more expensive than for turbines on a normalized per kWh generated basis, which also makes its interest rate proportionally more sensitive to variation. In either case however, H₂ enrichment can outperform SCR and reduce NO_x to a lower level helping the entity earn revenue through Emission Reduction Credits in addition to complying with local emission standards. Additionally, any increased capacity from new or expanded power plants must achieve the increasingly restrictive BACT. However, hydrogen enrichment achieves extremely low levels of NO_x and therefore could set the standard for BACT and help bring online more efficient power producers.

There are alternatives to SCR, such as steam injection. This NO_x emissions reduction technology uses the thermal mass of steam to decrease the maximum flame temperature and reduce thermal NO_x production and can achieve exhaust concentrations of 25ppm.

However, while steam injection does reduce NO_x, it can also increase CO emissions. It also decreases turbine efficiency, as some of the energy is lost to water or steam. Steam injection can also lead to a buildup of contaminants on the blades of turbine leading to a further reduction in efficiency and increased maintenance costs (Termaath et al. 2006). Despite these findings, other researchers claim efficiency improvements and even augmented power from steam injection due to the increased mass flow. (Jonsson and Yan 2005; Bolland and Stadaas 1995; Lee, Jeon, and Kim 2010).

Emissions Reduction Credits (ERCs)

Because H₂ enrichment can achieve lower emissions than SCR, it can further cut emissions to earn additional emissions reduction credits. Increases in the price per ton of NO_x will increase the value of alternative NO_x reduction strategies such as APR for H₂ enrichment, and in the SJVAPCD, prices have been on the rise (Figure 3). Similarly, more strict regulations that decrease emission limits could be a disruptive force for traditional power plants and help to drive the implementation of APR for H₂ enrichment systems in natural gas engines and turbines.

ERC values have historically fluctuated significantly even in the SJVAPCD, which regularly has the largest number of transactions in CA. In 2006, the value fell to a ten year low of \$13,074/ton. If this price for NO_x had been applied to the analysis, it would have reduced the value of ERCs from engines from 0.42 ¢/kWh to 0.11 ¢/kWh. However,

more recently, in 2013, the price of NO_x spiked to \$69,831/ton, which would increase the value of APR for H₂ enriched engines to 0.58 ¢/kWh. For turbines, this spread is similar, down to 0.051 ¢/kWh in 2006 and up to 0.27 ¢/kWh in 2013, in comparison to the 2012 value used above that yielded a value of 0.20 ¢/kWh.

VALUE OF RENEWABLE ENERGY

In a world with increasing regulatory pressure to reduce CO₂e emissions and incentivize low-carbon power, the value of renewably produced electricity is likely to continue to rise relative to conventionally produced, high-carbon electricity.

Feed-in-Tariff

While APR for H₂ enrichment does not yet qualify for CA's ReMAT program, this renewable technology could easily be added into legislation. If appropriate low carbon feedstocks are used, APR for H₂ enrichment could be compared to dedicated biomass power plants as net-zero carbon power production. Again, however, a thorough LCA must be conducted on the feedstock to ensure it is a carbon saving alternative.

Depending on participation, the feed-in tariff is subject to change according to DSIRE (2012). If there is too little interest in the first two months, the feed-in tariff would increase 0.4 ¢/kWh to 9.323 ¢/kWh, which would increase the marginal value of renewable electricity above the MPR to 0.27 ¢/kWh, from 0.17 ¢/kWh value using the

current feed-in tariff. If after a two more months, there is still not enough participation, the feed-in tariff would increase to 9.723 ¢/kWh and the marginal value would rise to 0.34 ¢/kWh. These values apply to both engines and turbines.

Cap-and-Trade

Using a carbon neutral feedstock, APR for H₂ enrichment can achieve significant reductions in GHG emissions. For the assumed H₂ enrichment concentration of 30% in the NG fuel stream, a 30% reduction CO₂e emission is estimated for a natural gas engine, and a 24% reduction for a natural gas turbine. The value these CO₂e savings are dependent on the price set on carbon. The 2013 average value of \$13.57/tonne CO₂e was used in the analysis above to estimate revenue for an engine of 0.15 ¢/kWh and 0.14 ¢/kWh for a turbine. However, the price of carbon is an important variable that will certainly change in future years. The price could conceivably drop to \$11.34/tonne, the floor price set to ensure the market does not collapse. At this minimum, an engine would generate 0.13 ¢/kWh and a turbine would drop to 0.12 ¢/kWh. On the other hand, if the price of carbon were to increase to \$20/tonne, an engine would produce 0.22 ¢/kWh and a turbine would earn 0.21 ¢/kWh through displaced costs or the sale of their carbon credits.

PRESENT VALUE OF APR FOR H₂ ENRICHMENT

The present value of APR for H₂ enrichment suggests that the implementation of this technology is financially viable for engine operators at or under \$33 million, and \$115 million for turbine operators. However, this value does not include any of the costs related to the APR system's operating costs or price of the biologically derived feedstock. As such, further economic analysis to determine the present value of the cost of APR for H₂ enrichment including O&M costs can be compared to this value to determine whether this technology is economically feasible.

VERSATILITY OF APR FOR DISTRIBUTED H₂ PRODUCTION

APR for H₂ enrichment provides a variety of economic benefits to the power producer. In this way, it could act as a disruptive technology driving the H₂ market forward. Initially, this technology could be implemented for the CO₂e and NO_x reductions, efficiency improvements, and an alternative path for renewable biomass derived feedstocks to offset fossil fuels. These applications of hydrogen sidestep the typical barriers to H₂ fuel, including carbon-neutral production, storage, and transportation. However, as the industry scales up, adopts and shares best practices, waste heat driven reformation processes may help drive innovation to integrate H₂ fuel into the market and pave the way for emissions free H₂ fuel in an attempt to curb fossil fuel consumption in power generation, transportation, and other end uses as the world energy demand grows.

CONCLUSIONS

APR for H₂ enrichment provides a variety of financial benefits to the power producer. First, natural gas is displaced in engines and turbines at a value of 0.91 and 0.88 ¢/kWh, respectively. Second, NO_x controls, such as SCR, are also displaced saving 0.31 ¢/kWh for engines and 0.16 ¢/kWh for turbines. Third, because H₂ enrichment is capable of pushing NO_x emissions below regulated levels, engines and turbines can earn ERCs yielding a value of 0.42 and 0.20 ¢/kWh, respectively. Fourth, H₂ enriched engines and turbines utilize renewably derived fuel qualifying them for CA Feed-in-Tariffs providing both power producing technologies with an additional 0.17 ¢/kWh. Finally, APR for H₂ enrichment reduces the carbon intensity of the electricity generated saving engine and turbine operators 0.15 and 0.14 ¢/kWh in the CA Cap and Trade market.

In sum, the value of APR for H₂ enrichment provides a financial benefit of 1.87 ¢/kWh for natural gas engines and 1.55 ¢/kWh for natural gas turbines, or a present value of \$33 million and \$155 million, respectively. The variety of benefits, as well as their respective and summed values from APR for H₂ enrichment demonstrate that it is a valuable, flexible, dynamic system that could be implemented for and tailored to a variety of different requirements.

APR for H₂ enrichment provides a variety of financial incentives to power plant operators. Overall, the total savings will need to be weighed against the capital and operation and maintenance costs of this new technology, including the cost of the carbon neutral feedstock. Additionally, NO_x and carbon emissions are significant contributors to the value of this technology and are expected to grow in importance as regional and national limits become more and more strict. In general, APR for H₂ enrichment is a promising technology but requires further technical and economic research before it proves itself as a viable option for power plants. Further research on hydrogen enrichment in natural gas turbines may also shed more light on the value of APR for H₂ enrichment as it applies to this technology. Technical and economic analyses of feedstocks are also important to ensure that the cost of biologically derived fuel does not outweigh the value of H₂ enrichment for the power producer.

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APPENDICES

APPENDIX A1. DISPLACED NATURAL GAS AND CO2 REDUCTIONS –
ASSUMPTIONS

Assume:			NG Specs	
Engine Capacity	23.00	MW	4.51	\$/1000 ft ³
Turbine Capacity	100.00	MW	5.73	\$/1000 ft ³
Capacity Factor	7500.00	hrs/yr	7.98	\$/1000 ft ³
WHR TCR	0.05	% increase of feedstock E	3412142	btu/MWh
H2 Enrichment	0.30	by V	1027	btu/ ft ³
	0.10	by E	Carbon Specs	
CO & CH4 Enrichment	0.10	by E	13.57	\$/tonne
FF E	0.78	%	0.0053	CO2/therm
			29.3001	kWh/therm
			0.1995	ton CO2/MWh NG
			0.1810	tonnes CO2/MWh NG

APPENDIX A2. DISPLACED NATURAL GAS AND CO₂ REDUCTIONS – ENGINE

CF	7500	hours/yr		
SC Eff	0.488	%	FF savings - H2 enrich	
Total E in	47.13115	MW	14.03	MW
Total GHG all FF	0.41	tons CO ₂ e/MWh e-	29.77%	% Reduction
TCR Enrich Eff	49.27%	%	105219	MWh/yr
TCR Eff Increase H2 Enrich Combustion Properties	0.0096	%		
TCR and H2 Enrich Eff	10.00%	% increase in eff	3.59E+11	btu/yr 1000
Total E in TCR and H2	54.20%	%	349583	ft ³ /yr
Bio E in	42.4384	MW	1,576,617	\$ Saved per year
Displaced FF	8.08	MW	0.914	¢/kWh
WH Recovered	14.03	MW		
Total FF E in	1.2529	MW		
Total GHG H2 Enrich	33.10	MW	Carbon Savings	
GHG Reduction from H2	0.29	tons CO ₂ /MWh e-	0.150	¢/kWh
GHG Savings	29.77%	%		
GHG Savings	0.11	tonnes CO ₂ /MWh e-	258371	\$/year
GHG Savings	110.38	kg/kWh e-		
GHG Savings	19040	tonnes/yr		Total ¢/kWh
Overall Eff Increase	11.06%	% Inrease in Eff by APR and H2 Enrich		1.064

APPENDIX A3. DISPLACED NATURAL GAS AND CO₂ REDUCTIONS –

TURBINES

CF	7500.00	hours/yr		
Capacity SC	100.00			
SC Eff	40.00%	%		
Total E in	250.00	MW	FF savings SC - H2 enrich	
Total GHG all FF	49.87%	tons CO2e/MWh e-	58.77	MW
TCR Enrich Eff	0.4038464	%	23.51%	% Reduction
TCR Eff Increase	0.0096155	%		
H2 Enrich Eff	1.00%	% increase in eff	440771	MWh/yr
TCR and H2 Enrich Eff	40.79%	%	2.E+12	btu/yr
				1000 cubic
Total E in TCR and H2	245.2	MW	1464433	feet/yr
				\$ Saved per year
Bio E in	46.70	MW	6604592	on fuel
Displaced FF	58.77	MW	0.881	¢/kWh
WH Recovered	7.24	MW		
Total FF E in	191.23	MW		
Total GHG H2 Enrich	0.38	tons CO2e/MWh e-	Carbon Savings	
			0.1443	¢/kWh
GHG Reduct	23.51%	%		
GHG Savings	0.11	tonnes CO2e/MWh e-		
Eff with H2 Enrich	40.79%	%	1082338	\$ saved/year
GHG Savings	106.346	kg/kWh e-		
GHG Savings	79760	tonnes/yr		
Overall Eff Increase	1.97%	%	Total	¢/kWh
				1.025

APPENDIX B1. SCR COSTS - ENGINES

Displaced SCR \$/kWh

Investment in yr 1	1,511,430.38
O&M yearly	268983.3724
NOx levels with SCR (g/kWh)	0.13
NOx levels w/o SCR (g/kWh)	1.3
Discount Rate (%)	0.1
Lifetime (yrs)	20
Average \$/euro 2003	1.113802784
2003 CPI:	184
2013 CPI:	232.957

kWh/yr			
	172500000	\$/year Nox Reduction	
		2003	2013
Annuity (A/P,i,n)		177532.0451	224768.1121
$A = P * ((i * (1+i)^n) / ((1+i)^n - 1))$			
O&M		268983.3724	340551.9537
Total		446515.4174	565320.0657
		\$/kWh	\$/ton reduced
		0.003277218	2541.062226

APPENDIX B2. SCR COSTS – TURBINES

Capacity (MW)	kWh/yr	Reduction (tons/yr)	Capital Cost (\$)	O&M Costs (\$/yr)
42.1	315750000	45	1,892,363	94,618
70.14	526050000	63	2,747,401	137,370
85.4	640500000	93	3,182,930	159,146
123.4	925500000	128	4,176,185	208,809
52.6	394500000	57	2,220,852	111,043
57	427500000	62	2,355,547	117,777
113.7	852750000	121	3,935,025	196,751
108	810000000	113	3,789,353	189,468
157	1177500000	162	4,945,922	247,296

Performance Loss (\$/yr)	Catalyst (\$/yr)	Ammonia (\$/yr)	Catalyst disposal (\$/yr)	Annuity	LCON 2006	LCON 2013 (\$/kWh)
106,092	90,784	5,958	3,437	192741	0.00156	0.00181
176,753	129,027	8,372	4,885	279829	0.00140	0.00162
215,208	149,840	12,338	5,673	324188	0.00135	0.00156
310,968	201,668	17,051	7,635	425354	0.00127	0.00146
132,552	105,105	7,548	3,979	226199	0.00149	0.00172
143,640	111,106	8,238	4,206	239918	0.00146	0.00169
286,524	188,438	16,131	7,134	400791	0.00128	0.00148
272,160	180,664	15,078	6,839	385954	0.00130	0.00150
395,640	247,494	21,496	9,369	503753	0.00121	0.00140

2006 \$			2013 \$		
NPV (\$/ton)	NPV (\$/kWh)	NPV (¢/kWh)	NPV (\$/ton)	NPV (\$/kWh)	NPV (¢/kWh)
10652.29	0.0015	0.1518	12309.16	0.0018	0.1754
11357.27	0.0014	0.1360	13123.78	0.0016	0.1572
9057.84	0.0013	0.1315	10466.71	0.0015	0.1520
8906.07	0.0012	0.1232	10291.33	0.0014	0.1423
9994.21	0.0014	0.1444	11548.72	0.0017	0.1669
9792.14	0.0014	0.1420	11315.22	0.0016	0.1641
8810.58	0.0013	0.1250	10180.99	0.0014	0.1445
9040.48	0.0013	0.1261	10446.64	0.0015	0.1457
8566.25	0.0012	0.1179	9898.65	0.0014	0.1362

APPENDIX C1. NO_x COSTS – ENGINES**ERCs (\$/kWh)**

Linear Interpolation

g/kWh	ppmv	g/kWh	(Warts ULE)
0.13	5	0.082	
	9	0.125	

H2 Enrichment

ppmv	4
g/kWh	0.07125

SJVACPD Limits as applies to 23MW

Wartsila Engine

ppmv	11
g/kWh	0.1465

Wartsila ULESpecs

ppmv	9.465
g/kWh	0.13

hrs/yr 7500

Avg Cost/Ton 69,831

g/ton 907184

kW 23000

Tradable Tons from H2 Enrichment of Wartsila's 23MW Engine	
Tradable Tons/Yr from ULE	14.30868976
Value of Tradable Nox \$/Yr	999190.1147
Value of Tradable Nox \$/kWh	0.005792406

Tradable Tons from ULE	
Tradable Tons/Yr from ULE	3.137453569
Value of Tradable Nox \$/Yr	219091.5202
Value of Tradable Nox \$/kWh	0.001270096

APPENDIX C2. NO_x COSTS – TURBINES

Make	Model	Operating Output (MW)	Nox Flow (tons/yr @5ppm and 7500hr/yr)
GE	MS6001B	42.1	20.625
GE	MS6001FA	70.14	29.0625
GE	MS7001EA	85.4	43.125
GE	MS9001E	123.4	60
ABB Alstom Power	GT8C	52.6	26.25
ABB Alstom Power	GT8C2	57	29.0625
ABB Alstom Power	GT11N2	113.7	57.1875
Siemens AG	V84.2	108	53.4375
Siemens AG	V94.2	157	75.9375

Nox Flow (tons/yr @2ppm) (linear Interpolation from 5 and 3ppm)	\$/kWh (2ppmv CA ERC)
7.9688	0.002046
12.1875	0.001637
17.8125	0.002017
23.4375	0.002016
10.7813	0.002001
12.1875	0.002015
22.0313	0.002104
21.0938	0.002038
29.5313	0.002011

Average 0.001987309 Ave \$/yr (100MW Capacity) 1490481.519
