

Carbon dioxide emissions from fired heaters

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Fired heaters emit an estimated 400 to 500 million tons of carbon dioxide (CO₂) every year. At least 73% of average refinery CO₂ emissions come from combustion¹. For refineries and petrochemical plants focused on reducing greenhouse gas emissions, it makes sense to target CO₂ from fired heaters. Fired heaters usually have a fuel efficiency of 70-93%, so improvements in fuel efficiency enable CO₂ reduction. They are typically fuelled by either carbon-bearing refinery fuel gas or natural gas, so further CO₂ reduction is possible by changing to fuels with lower carbon content.

Project Economics for Increasing Efficiency

Many of the fired heaters that are large emitters of CO₂ are already the most efficient. Reduced fuel consumption from a refinery's highest heat release heaters reduces the operating cost of the refinery. Installation costs do not scale linearly with heater size and so smaller units have been less attractive targets for efficiency increasing projects. Anecdotally, the fuel efficiency of existing heaters varies throughout the world with the regions having the highest fuel cost also have the most efficient heaters. While the high efficiency of the largest CO₂ emitting heaters may be beneficial to the existing CO₂ footprint of a refinery, it also leaves less room for improvement by increasing heater efficiency.

Figure 1 shows the justifiable total installed cost for fired heater improvements compared to a 70% fuel-efficient heater for various fuel and CO₂ cost scenarios labelled with numbers (1-4). The graph can be used to estimate a justifiable

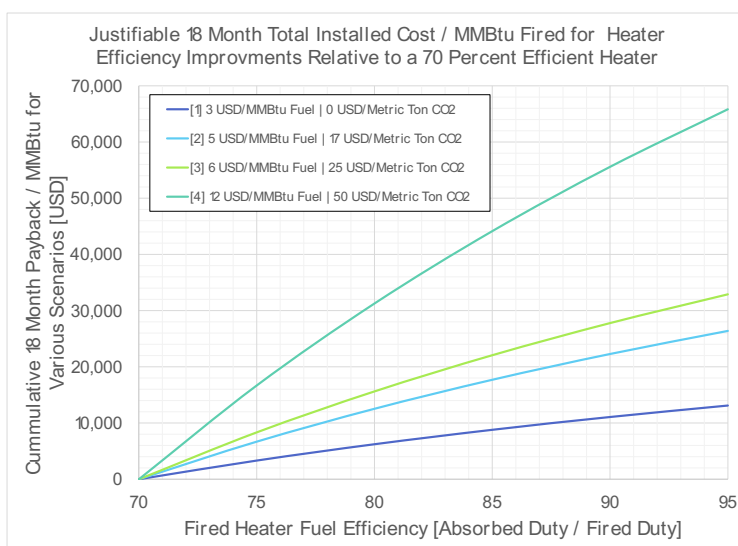


Figure 1 This graph shows the required total installed equipment cost for an 18-month payback relative to a 70% efficient heater.

18-month return-on-investment (ROI) project cost when moving between any two points on the horizontal axis and multiplying by the fired duty of the heater. The calculations used to generate the graph assume 340 days of operation per year. To scale the acceptable project cost by a different time frame, multiply the result by the ratio of 18 months to the new time frame. A description of the listed scenarios follows:

- 1. Fuel cost: 3 USD/MMBtu | CO₂ Cost 0 USD/ton CO₂:** This scenario represents most of the USA at the time of writing.
- 2. Fuel cost: 5 USD/MMBtu | CO₂ Cost 17 USD/ton CO₂:** This scenario represents California where there is a functioning carbon market at the time of writing.
- 3. Fuel cost: 6 USD/MMBtu | CO₂ Cost 25 USD/ton CO₂:** This scenario represents much of the EU at the time of writing.

4. **Fuel cost: 12 USD/MMBtu | CO₂ Cost 50 USD/ton CO₂:** This scenario represents a likely future state in the EU within the next 10 years.

For example, in scenario 1 using a fuel cost of 3 USD / MMBtu and 0 USD / ton CO₂, which would be most regions of the USA, a project to increase a 50 MMBtu/h LHV fired duty heater from 80% efficiency to 90% efficiency would require a total installed cost to break even over 18 months as follows:

$$\begin{aligned} & \text{Eighteen Month Break Even Total Installed Cost} \\ &= \left(11,074 \frac{\text{USD} \cdot \text{h}}{\text{MMBtu}} @90\% \text{ Efficiency} - 6,229 \frac{\text{USD} \cdot \text{h}}{\text{MMBtu}} @80\% \text{ Efficiency} \right) \\ &\times 50 \frac{\text{MMBtu}}{\text{h}} = 242,250 \text{ USD} \end{aligned}$$

In scenario 3, which would be like current fuel and CO₂ costs in the EU, the same project has a justifiable cost as follows:

$$\begin{aligned} & \text{Eighteen Month Break Even Total Installed Cost} \\ &= \left(27,787 \frac{\text{USD} \cdot \text{h}}{\text{MMBtu}} @90\% \text{ Efficiency} - 15,630 \frac{\text{USD} \cdot \text{h}}{\text{MMBtu}} @80\% \text{ Efficiency} \right) \\ &\times 50 \frac{\text{MMBtu}}{\text{h}} = 607,838 \text{ USD} \end{aligned}$$

Operating Expenses for Purchased Hydrogen

Redirecting hydrogen to the fired heater fuel gas system is a very effective way to reduce carbon dioxide emissions. If one can sell the hydrogen from the fuel gas system, or if the hydrogen must

be purchased, the operating expenses vary dramatically depending on both the cost of hydrogen and carbon credits. Hydrogen can come from various sources. ‘Green’ hydrogen is produced from completely renewable sources such as solar. The production of ‘blue’ hydrogen results in carbon dioxide emissions that are sequestered. ‘Gray’ hydrogen is produced in the conventional manner, usually reforming, without sequestration of the resulting carbon dioxide.

Figure 2 shows eight different operating scenarios for the addition of hydrogen to the fuel gas stream used to fire heaters. Hydrogen costs were estimated at 2.50–6.80 USD/kg for green hydrogen, blue hydrogen at 1.40–2.40 USD/kg, and grey hydrogen at 1.00–1.80 USD/kg². In scenarios (3), (6), and (8) the break-even price for adding hydrogen is calculated. For those scenarios, it is cost neutral to add any level of hydrogen, up to completely displacing all organic molecules, in the fuel of the heater. A description of the different operating scenarios follows:

1. **Fuel Cost: 3 USD/MMBtu | 1.00 USD/kg H₂ | 0 USD/ton CO₂:** This scenario represents the current operating state most of the USA using low-cost ‘gray’ hydrogen.
2. **Fuel Cost: 5 USD/MMBtu | 6.80 USD/kg H₂ | 17 USD/ton CO₂:** This scenario represents using high-cost green hydrogen in California where there is a functioning carbon market.
3. **Fuel Cost: 5 USD/MMBtu | 0.65 USD/kg H₂ | 17 USD/ton CO₂:** This scenario represents the required cost of hydrogen in California where there is a functioning carbon market such that there is no increased expense in operating the heater.
4. **Fuel Cost: 6 USD/MMBtu | 6.80 USD/kg H₂ | 25 USD/ton CO₂:** This scenario represents using green hydrogen in a European refinery to supply some portion of the fuel to a fired heater.
5. **Fuel Cost: 6 USD/MMBtu | 1.40 USD/kg H₂ | 25 USD/ton**

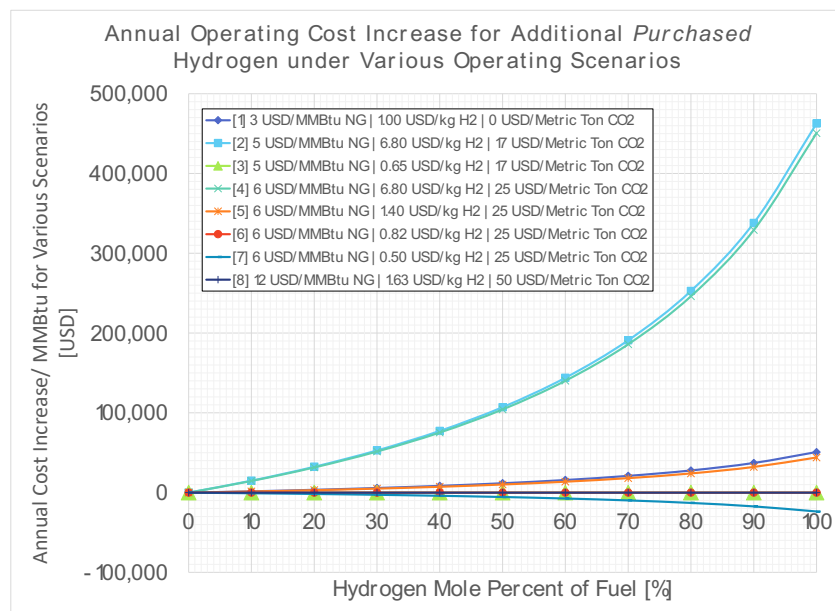


Figure 2 This graph shows the increase in operating cost for adding purchased hydrogen to the fuel gas under various operating scenarios relative to no addition of hydrogen to natural gas fuel.

Compound	Fuel 1	Fuel 2	Fuel 3
CH ₄ [mole fraction]	0.5	0	0
H ₂ [mole fraction]	0.5	1	0.94
C ₆ H ₁₄ [mole fraction]	0	0	0.06
Mix Heating Value [Btu/SCF]	592	274	522
Mix Specific Gravity	0.31	0.07	0.25
Wobbe Number	1056	1036	1054
% Difference in Wobbe Number from Fuel 1	0.00%	-1.89%	-0.25%

Table 1 Comparison of Mixed Fuel Wobbe Numbers

CO₂: This scenario represents using high-cost grey hydrogen in a European refinery to supply some portion of the fuel to a fired heater. Note that it is very close in cost to using low-cost grey hydrogen in the USA with no carbon incentive.

6. **Fuel Cost: 12 USD/MMBtu | 0.76 USD/kg H₂ | 25 USD/ton CO₂:** This scenario represents using the required cost of hydrogen in a European refinery for cost-neutral use of hydrogen in a fired heater. The required hydrogen cost is 46% less than high-cost grey hydrogen or 24% less than low-cost grey hydrogen. If hydrogen production costs go down or CO₂ costs go up this could be an operating scenario soon. However, the production of grey hydrogen still releases CO₂ into the atmosphere.
7. **Fuel Cost: 6 USD/MMBtu | 0.50 USD/kg H₂ | 25 USD/ton CO₂:** This scenario represents current European operating costs. It also shows that, if hydrogen could be purchased for 0.50 USD/kg that the heater would make additional money for every hour of operation due to the potential sale of the carbon credits generated.
8. **Fuel Cost: 12 USD/MMBtu | 1.52 USD/kg H₂ | 50 USD/ton CO₂:** This scenario could represent a European refinery in the next 10 years using blue hydrogen. In this case, the hydrogen that is used to fuel the heater is produced from a source with sequestration. The operation of the heater is also cost-neutral compared to the current operation – no additional cost is required to operate the heater regardless of the amount of hydrogen added to the fuel.

Figure 2 shows the additional operating cost of adding purchased hydrogen to the fuel gas supply

of a heater normalised by the heat release. So, for example, to fire 50% additional green hydrogen in a 50 MMBtu/h heater in California at current prices (Figure 2, scenario 2), it would cost an additional:

$$\text{Total Yearly Additional Cost} = 107,085 \frac{\text{USD} \cdot \text{h}}{\text{MMBtu} \cdot \text{y}} \times 50 \frac{\text{MMBtu}}{\text{h}} = 5,354,250 \frac{\text{USD}}{\text{y}}$$

In the EU with grey hydrogen the cost becomes (Figure 2, scenario 5):

$$\text{Total Yearly Additional Cost} = 10,180 \frac{\text{USD} \cdot \text{h}}{\text{MMBtu} \cdot \text{y}} \times 50 \frac{\text{MMBtu}}{\text{h}} = 509,000 \frac{\text{USD}}{\text{y}}$$

Wobbe Number and Fuel Gas Interchangeability

Combustion equipment is designed for specific fuels or a range of fuel blends. When the burner or heater uses a fuel composition outside of this design range it may not operate correctly. The combustion characteristics of hydrogen are very different from hydrocarbons that, aside from inert components, make up a typical refinery fuel gas. A well-known measure used to compare fuel gas interchangeability is the Wobbe number (sometimes Wobbe index). If the Wobbe number of two fuels match, then the heat supplied at a given pressure will also match. The Wobbe number is calculated as follows³:

$$W = \frac{\text{Heating Value} \frac{\text{Btu}}{\text{SCF}}}{\sqrt{\text{Specific Gravity}}}$$

Most modern burners used in fired heaters can use a wide range of fuel compositions. It is not uncommon in acceptance testing that the burner will be validated firing anywhere from 100% natural gas to 80% hydrogen. Older burners may not have been tested to support high hydrogen firing.

When increasing hydrogen in the fuel gas, seemingly close Wobbe numbers can result in fuels that are not interchangeable. For example, Table 1 shows a comparison of a 50% CH₄/50% H₂ fuel blend (Fuel 1) as a reference fuel to two

other fuels. These simplified fuel blends are used as an example of the difficulty, with real refinery fuel blends containing many more constituents. The Wobbe number of a 100% hydrogen fuel is only 1.89% different from the reference fuel, but it would almost certainly flashback in any premix burner. With optimization, the heating value and specific gravity can be much more closely matched while still using a relatively high volumetric proportion of hydrogen. The Fuel 3 blend heating value is only 12% different from Fuel 1 and the specific gravity is 20% different. The resulting Wobbe number is only 0.25% different from the reference fuel, but again a 94% hydrogen fuel would almost certainly flashback (allowing the flame to propagate upstream into the burner body and damage the burner) in a wide variety of burners.

Flame Speed Considerations

Table 2 shows flame speeds for four fuel constituents as an example⁴. The flame speed is the speed below which the flame will propagate upstream into the unburned reactants. When the speed of the fuel and oxidiser match the flame speed the flame front will remain stationary. If the speed of the reactants is higher than the flame speed, the flame will “lift-off” to a point where it can stabilise or “blow-off” and extinguish. Industrial burners typically stagnate the flow against a bluff body or another jet so that there is always a stagnation point to anchor the flame, preventing lift-off. However, for premix burners, there is usually no

Fuel	Laminar Flame Speed [ft/s]
NH ₃	0.26
CH ₄	1.48
C ₃ H ₈	1.52
H ₂	9.30

Table 2 Flame speed for some fuel constituents

mechanism to prevent the flame from propagating upstream as flame arrestors typically require more airside pressure drop than is afforded to the burner in the system design.

Most hydrocarbons have a flame speed of approximately 1.5 ft/s. The flame speed of hydrogen is an order of magnitude higher.

The flame speeds listed are lam-

inar, but one can also witness the general difference in behaviour in turbulent combustion flames. It is this large difference in flame speed that causes most premix burners to flashback.

It has also been this author’s experience that even nozzle mix burners may exhibit flame instability when changing to high hydrogen fuels. This is counter-intuitive because the higher flame speed and flame temperature of higher hydrogen fuel would generally cause a more robust flame closer to the burner. Most industrial burners are not strictly ‘premix’ burners where the fuel and air are mixed before the flame or ‘nozzle mix’ (also called diffusion flame) burners where the fuel and air first mix at the flame front. In most burners, choked flow nozzles mix some small portion of air or oxygen-bearing flue gas before the main flame front with fuel. Often, these mixing points occur in the annulus of a flame-holder or a flue gas recirculation port. If these locations, meant to be clear of flame, instead have flame propagate into them, the burner flame can become unstable and extinguish.

Material Considerations with Increased Hydrogen in the Fuel

Materials near the flame, either in the burner or heater, are selected according to the expected temperature and chemistry. Increasing the local temperature can rapidly destroy these materials. Table 3 shows adiabatic flame temperatures for various common refinery fuel components. One can see that if the fuel is changed and the local heat transfer away from the flame is

Component	Formula	Flame Temperature (°F)
Methane	CH ₄	3565
Ethene (Ethylene)	C ₂ H ₄	4249
Ethane	C ₂ H ₆	3551
Propane	C ₃ H ₈	3596
n-butane	C ₄ H ₁₀	3578
n-Pentane	C ₅ H ₁₂	3591
Hydrogen	H ₂	4089

Table 3 Adiabatic flame temperatures for various fuel components

not increased as well, the local temperature for a hydrogen flame can rise by 524°F.

For example, 304 stainless steel has a high-temperature use limit of approximately 1500°F and is often used in internal burner components⁵. If the local temperature were near to this for a burner originally designed to burn methane, the component could pass the high-temperature oxidation limit when the hydrogen content of the fuel is surpassed.

In addition to changes in temperature, one also must be aware of changes in chemistry. Burner tiles (also called ‘blocks’ or ‘quarls’) are often made of 60% alumina refractory. These refractory materials often have a substantial proportion of silica. In many burner designs, the stagnation point used to stabilise the flame is formed by impinging a fuel jet on this burner tile. From reference data, in a 2534°F hydrogen atmosphere, a brick of this material can lose 15% of its mass in only 50 hours of operation due to chemical attack⁶. Although this temperature is high compared to a refinery furnace arch temperature, the tile can become this hot locally due to the proximity of the flame. High alumina refractory reduces or eliminates this mass loss.

Figure 3 shows the normalised effect of changing temperature and efficiency on the peak tube metal temperature. The data used to make this graph was derived from a Lobo-Evans style calculation for a fixed radiant section and process heat transfer. When changing from low efficiency, 100% methane fired heater to a high efficiency 100% hydrogen fired heater the peak tube metal temperature changes by as much as 1.4% on an absolute basis. One should also note that changing towards 100% hydrogen fuel has a greater effect than increasing the efficiency on the peak tube metal temperature. If you are operating near the peak tube metal temperature in your fired heater this temperature increase should certainly be a consideration.

NOx Emissions with Increased Hydrogen in the Fuel

Adiabatic flame temperature can be used to scale most of the difference in NOx production between operating cases given a baseline NOx production from a burner. In other words, if you know the NOx production from a heater at a given adiabatic flame temperature, you can calculate the NOx produced at a new adiabatic temper-

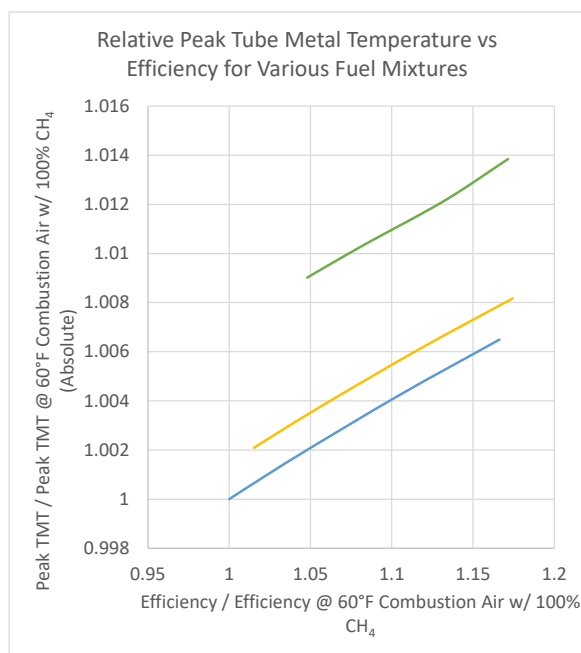


Figure 3 Calculated peak tube metal temperature versus heater efficiency for various fuels

ature scaling from the exponential relationship between temperature and NOx. Specific burners under specific circumstances may vary but the general relationship holds.

Given this information, one can plot the change in emissions for adding hydrogen to the fuel gas. Figure 4 shows the change in NOx and CO₂ emis-

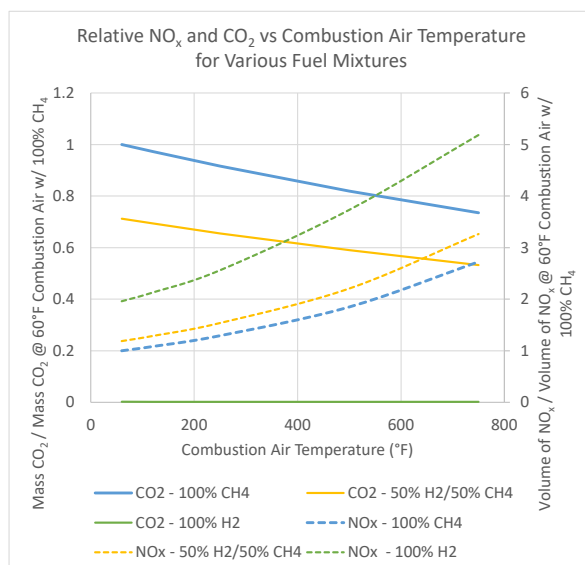


Figure 4 Change in NOx and CO₂ emissions at various combustion air temperatures for various fuel blends

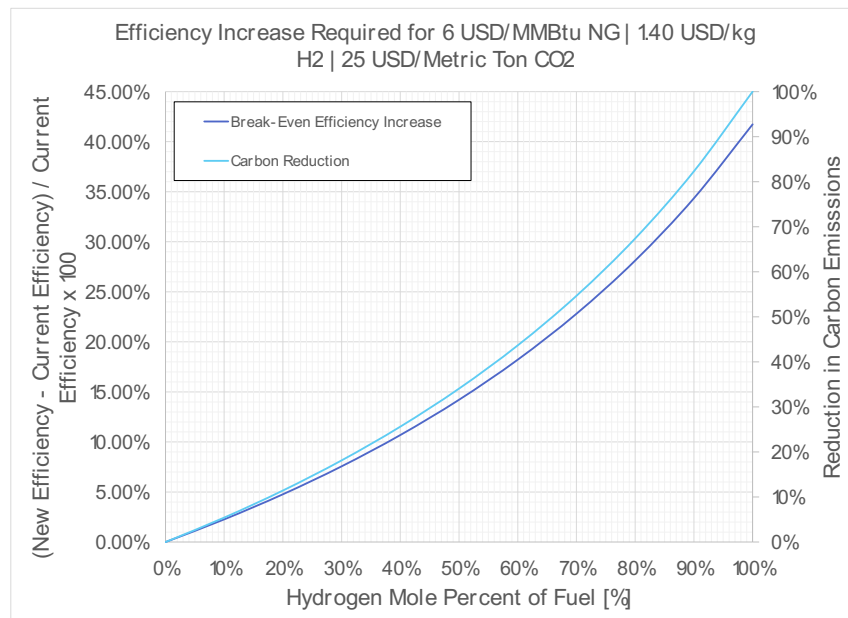


Figure 5 Efficiency improvement required for no operating cost increase over current costs

sions versus combustion air temperature for 100% CH₄ combustion, a 50% CH₄/50% H₂ blend of fuel, and a 100% hydrogen fuel. The NO_x for the 100% hydrogen fuel is twice that of the 100% CH₄ mixture. Sufficient operating margin below the NO_x permit limit or a plan to reduce NO_x must be in place.

Planning Your Increase in Hydrogen Fuel Use

How does one vet the different effects when considering increasing hydrogen in a heater fuel gas system? The following list can provide a preliminary guide:

- Check burner data books and test reports from the factory acceptance testing for the valid hydrogen range.
- If you plan to operate outside the tested hydrogen range, see if the burner manufacturer has data supporting higher hydrogen use for the specific burners in your heater. Be aware that even burners with the same model number and size may have different fuel port dispositions, material of construction, and flame holder designs.
- Consider replacing low alumina burner tiles with high alumina (85% or greater).
- If the data or a reference installation that the manufacturer warrants to be identical is not available, you will have to test the burners.
- If you are supplied with new fuel nozzles for

high hydrogen operation, be aware the flame quality will likely suffer for low hydrogen fuels.

- You may need to reset the low- and high-pressure fuel trips on the heater.

- The airflow requirement is much lower for high hydrogen fuels than high carbon fuels. It may be difficult to size the burner for both. The reduced flue gas flow will also reduce the velocity and heat transfer across the convection section.

- You may need new pressure sensors to cover the entire fuel pressure range.

- Compare the measured

tube metal temperature versus the new potentially increased tube metal temperature.

- Ensure that you will not exceed NO_x limits when increasing the hydrogen content in the fuel.

Optimising Hydrogen Usage

Returning to the economic calculations in the first section of this paper, one can see that increasing heater efficiency reduces operating costs and increasing the amount of hydrogen increases operating costs. Both steps reduce carbon dioxide emissions. Increasing efficiency also reduces hydrogen consumption when hydrogen is added to the fuel gas system. Using this observation, one can calculate the efficiency required to make operation with added hydrogen completely offset the added cost.

Figure 5 shows the efficiency increase required to completely offset the cost of hydrogen using fuel, blue hydrogen (hydrogen where the CO₂ from production has been sequestered), and emissions credit prices like in the EU. This provides a guide to which heaters are good candidates for efficiency projects to reduce hydrogen. For example, a project that increases efficiency by 15% and adds 50% hydrogen to the fuel will completely offset any additional cost of operating with hydrogen and reduce CO₂ emissions by 34%. The post-improvement project hydrocarbon fuel cost, hydrogen fuel

cost, and carbon dioxide cost are set to be equivalent to the pre-project hydrocarbon fuel cost and carbon dioxide cost so there is no pay-back for the curves shown. To achieve a payback, the hydrogen costs would have to be lower or the carbon dioxide prices higher given the same efficiency increase. Projects such as these are particularly attractive because they do not change the current profitability of the refinery but result in sizeable carbon dioxide reductions.

Conclusions

Reduced fuel costs from efficiency improvements can pay for the project within an industry-accepted timeframe. Higher fuel and carbon costs make these projects more attractive for a wider range of heaters. Adding hydrogen to the fuel gas system also reduces the carbon emissions from fired heaters but can greatly increase operating costs. Lower hydrogen costs and higher carbon costs make the addition of hydrogen more attractive.

Numerous technical details must be considered when increasing hydrogen use. These include the flame speed, materials of construction, heat transfer, and NO_x. Other items must be considered such as whether the current burners can operate with increased hydrogen and the low- and high-pressure trips on the heater.

As hydrogen costs come down and carbon dioxide prices rise, adding hydrogen to the fuel gas system of a fired heater will become more attractive. For refineries that are fuel-long it is difficult to justify the replacement of fuel gas with hydrogen on an economic basis but for carbon credit prices. For other refineries, when coupled with an efficiency improvement project, the operating cost of the heater can remain the same while at the same time achieving sizeable carbon dioxide emissions reductions.

Links

More information about refueling and increasing efficiencies:

[Refuel Your Future](#)

[XRG Completes Turnkey Heater Efficiency Project](#)

[10 Easy Hacks for Heater & Combustion Engineers](#)

References

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