Understanding thermal oxidisers

Dealing with common misconceptions on the design of vapour and liquid waste thermal oxidiser systems

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There are many similarities between thermal oxidisers and fired heaters. A thermal oxidiser and a fired heater both include one or more burners, an insulated refractory-lined combustion chamber, and a fuel measurement and control system. Both can be designed to operate under either forced draft or natural draft conditions. However, the similarities between them quickly begin to diverge upon a detailed examination of their design and intended function (see Figure 1).

The purpose of a fired heater is to heat a process fluid using fuel gas or oil. Examples of common fired heater applications are:

- Ethylene cracking furnaces
- Thermal fluid heaters
- Crude oil heaters
- Regeneration gas heaters
- Delayed coker heaters.

The primary purpose of a thermal oxidiser is efficient waste stream destruction. Common thermal oxidiser applications include:

- Tail gas from sulphur recovery systems in natural gas plants and refineries
- Chlorinated hydrocarbons from vinyl chloride monomer manufacturing
- Vent streams from batch reactors
- Vents from tank farms
- Waste solvents from pharmaceutical manufacturing
- Tail gas from carbon black manufacturing
- Carbon monoxide-laden regeneration flue gas from catalytic cracking furnaces.

The function of a thermal oxidiser is to efficiently destroy hydrocarbons and other environmental contaminants; therefore, it must be designed with sufficient mixing, reaction time, reaction temperature and excess flue gas oxygen content to achieve the goal. On the other hand, the function of a fired heater is to efficiently heat process fluids, so it is designed to conserve fuel. This primary functional difference results in the primary design difference. A thermal oxidiser's combustion chamber is lined with refractory and sized for one to two seconds of flue gas residence time before contact with heat transfer surfaces. In contrast, a fired heater typically has heat transfer surfaces located very close to the flame. Thus, a fired heater has no refractory-lined chamber separating the flame from the heat transfer tubes. If a fired heater was used as a thermal oxidiser, the cold heat transfer surfaces would inhibit efficient destruction of hydrocarbons. If a thermal oxidiser was used as a fired heater, the NOx emissions would be higher than expected; the cost to heat the fluids would be unnecessarily high due to the purposeless refractory-lined chamber upstream of the heat recovery section; and the fuel usage would be higher.

API Standard 560

A thermal oxidiser is not a fired heater. In fact, the two are, at best, only distant cousins for reasons already discussed. However, in the absence of a clearly defined design standard, many engineers attempt to adopt API Standard 560 (API 560), entitled Fired Heaters for General Refinery Service, as a primary thermal oxidiser design specification.

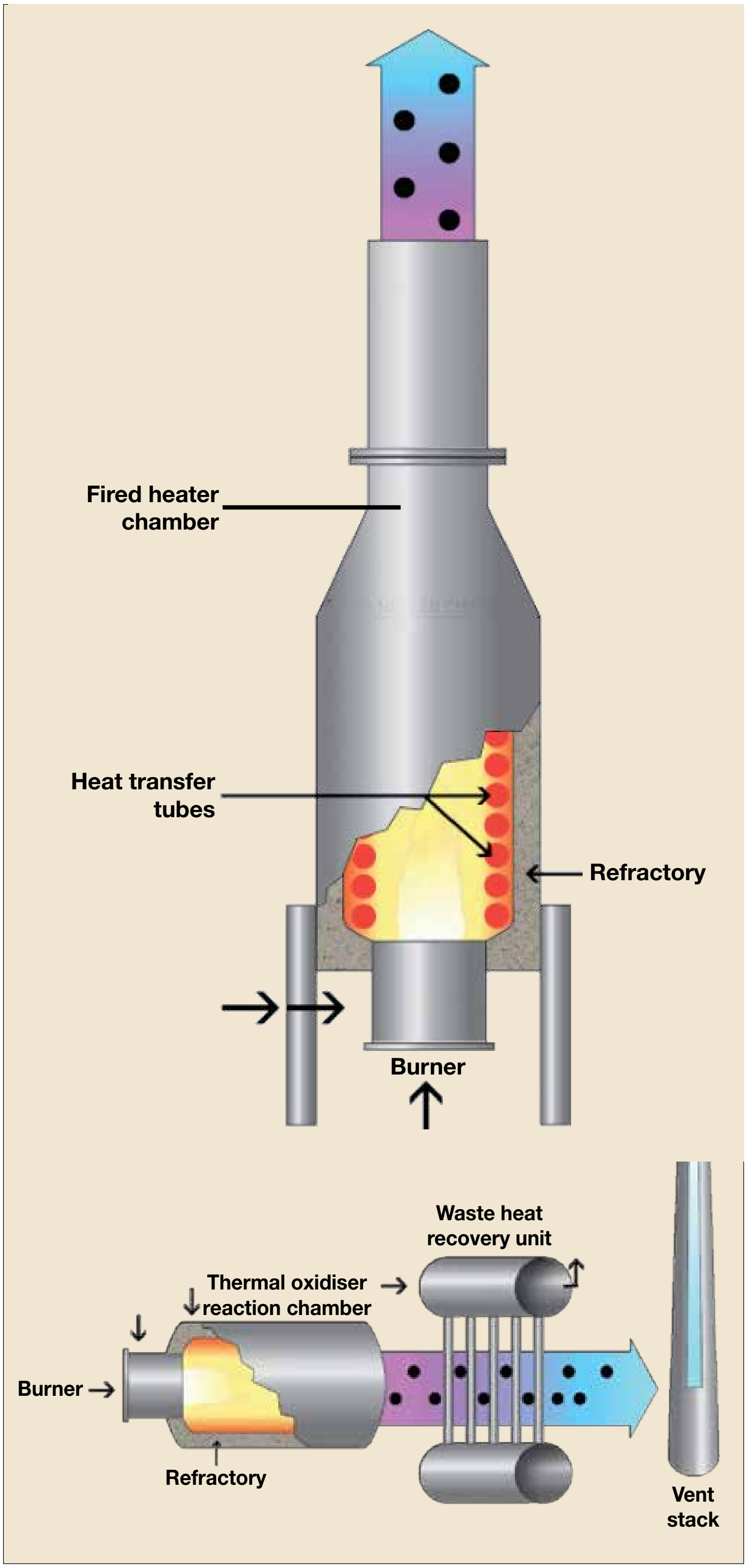

Figure 1 Arrangements of a fired heater (top) and a thermal oxidiser (bottom)

The first two paragraphs of API 560 are:

Paragraph 1.1.1 This standard covers the minimum requirements for the design, materials, fabrication, inspection, testing, preparation for shipment, and erection of fired heaters, air preheaters, fans and burners for general refinery service.

Paragraph 1.1.2 A fired heater is an exchanger that transfers heat from the combustion of fuel to fluids contained in tubular coils within an internally insulated enclosure.

Notice that thermal oxidiser (or incinerator) is not mentioned in either of these statements. Nor is "thermal oxidiser" or "incinerator" listed in the Definition of Terms, mentioned or illustrated anywhere else in the entire document.

There are 14 sections of API 560. Of these, only two — Section 7, Refractory and Insulation, and Section 11, Centrifugal Fans and Drivers for Fired Heater Systems — are primarily related to the design of a thermal oxidiser.

The first paragraph of Section 7, Refractory and Insulation, is quite often incorrectly applied to a thermal oxidiser. This paragraph, labelled as "optional," limits the shell temperature of the "outside casing of the radiant and convection sections and hot ductwork" to 82°C (180°F). This may be acceptable for fired heaters, where the main purpose is the efficient use of energy, but it is frequently unacceptable for a thermal oxidiser. Limiting the shell temperature can create many problems with the design of a thermal oxidiser. These problems include:

- Most thermal oxidisers are internally lined with some combination of a firebrick and castable lining. The inclusion of an 82°C shell requirement maximises the thickness of this lining, resulting in a larger thermal oxidiser vessel and higher capital cost
- If we assume that the reason for the low-temperature casing requirement is the conservation of energy, it makes very little sense for a thermal oxidiser burning an exothermic waste to incorporate this feature, unless there is some type of downstream heat recovery involved and energy conservation is very important. Even for a thermal oxidiser using fuel gas to burn an endothermic waste, the amount of heat lost from the shell is usually a minor fraction of the total heat release. In these cases, an in-depth analysis should be performed to determine if the low-temperature shell justifies the requirement for larger equipment and higher capital cost
- Many thermal oxidisers burn wastes containing elements (such as sulphur, halogens and sometimes phosphorus) that create acid gases with dew points well above the API 560's recommended shell temperature. The long-applied solution for handling high sulphuric acid dewpoint problems in the sulphur industry has been to design thermal oxidisers with casing temperatures at least 28°C (50°F) above any anticipated sulphuric acid dewpoint and then enclose the thermal oxidiser shell with a rain shield (either aluminium, galvanised steel or stainless steel). The rain shield maintains the thermal oxidiser shell at a fairly constant operating temperature, regardless of the ambient weather conditions. This outer rain shield also serves as personnel protection by providing an external surface that is below 120°F.

NOx emissions

Fired heater NOx emission requirements are often mistakenly applied to thermal oxidisers. Fired heaters typically fire fuel gas and air into a chamber containing a heat transfer surface. Even though the flue gas from a fired heater may contain only 2% to 3% oxygen, the flame temperatures in the heater are minimised and produce less NOx. This is because recently developed burner technology such as that employed by the patented Zeeco GLSF Free Jet Ultra-Low NOx burner circulates low oxygen flue gas that has been cooled by the internal heat transfer surface. The circulating flue gas decreases burner flame temperatures and reduces NOx emissions. In thermal oxidisers, waste gases of various compositions are fired in refractory-lined adiabatic chambers. In high excess air applications, there are no low-oxygen, cooled flue gases to circulate. The oxygen content and temperatures in these adiabatic chambers are often higher than in fired heaters. This means thermal oxidisers frequently generate more NOx than fired heaters designed for a similar heat release.

Regulations regularly specify fired heater NOx emissions in units of mass divided by heat release based on a lower heating value (for example, lb/MMBtu LHV). For a system firing fuel gas and air, the conversion of lb/MMBtu to flue gas concentration is almost universally repeatable. For instance, an emission requirement of 0.2 lb/MMBtu when firing natural gas and air will correspond to a flue gas NOx concentration of 150 parts per million by volume (ppmv) corrected to 3% oxygen, dry basis. This relationship between lb/MMBtu and flue gas concentration will hold true as long as the fuel gas composition contains mostly organic compounds. The relationship does not hold if the fuel gas contains significant amounts of inerts (nitrogen or carbon dioxide) or hydrogen.

The compositions of the wastes and fuels fired in thermal oxidisers will vary significantly. In fact, seldom are any two thermal oxidiser applications identical. For example, consider two different thermal oxidiser applications using natural gas as fuel. The waste gas to thermal oxidiser A is essentially 100% nitrogen; the waste gas to thermal oxidiser B is 100% CO_2. With both thermal oxidisers at the same fuel firing rate, thermal oxidiser A with the N_2 waste can handle more waste than thermal oxidiser B with CO_2 waste. Assume the NOx requirement is specified at 0.2 lb/MMBtu for each thermal oxidiser. This will translate to flue gas NOx concentrations of 28 ppmv and 35 ppmv, respectively (values corrected to 3% oxygen, dry basis) for A and B, with both thermal oxidisers operating at 1600°F (1800°C). If the thermal oxidisers should

Figure 2 Two vertical low-NOx thermal oxidisers used for NOx reduction

have to operate at 1800°F (982°C) to achieve a higher waste destruction efficiency, the 0.2 lb/MMBtu value now corresponds to 32 ppmv and 40 ppmv, respectively, for A and B.

The above example, plus the fact that it is usually more difficult to control NOx in a thermal oxidiser than in a fired heater, demonstrates that NOx regulations for fired heaters should not be generally applied to thermal oxidisers (see Figure 2).

Figure 3 Sulphur recovery unit (SRU) tail gas thermal oxidiser with a fire tube-style waste heat boiler. This unit is designed for a total 75 MW heat release

Sulphur oxide (SOx) emissions

SOx is produced in flue gas by the presence of sulphur-containing combustibles in the feed streams. These are commonly elemental sulphur, H_2S, COS, CS_2 and various mercaptans. The most common reactions are:

$$S + O_2 \rightarrow SO_2$$

$$H_2S + O_2 \rightarrow H_2O + SO_2$$

$$COS + O_2 \rightarrow CO_2 + SO_2$$

$$CS_2 + O_2 \rightarrow CO_2 + SO_2$$

Carbon monoxide can be further oxidised to CO_2 by efficient burner and oxidiser design:

$$CO + O_2 \rightarrow CO_2$$

NOx production can be inhibited, as discussed above. However, while it is possible to design a burner that will minimise NOx and CO, it is not possible to design a combustion system to minimise SO_2 formation. CO_2 is the normal, expected and intended product of combustion for any compound containing carbon. Similarly, SO_2 is the normal, expected and intended product of combustion for sulphur compounds. Therefore, sulphur content in the feed will produce a predictable quantity of SOx (SO_2 and SO_3) in the flue gas, independent of burner or combustion system design (see Figure 3).

The only way to lower SOx emissions is to remove sulphur from the feed stream or remove SOx from the flue gas with SOx scrubbing equipment such as a spray tower, packed column or a dry scrubber. However, due to the high cost of such systems and high water usage, the typical solution is a tall vent stack (45-65 m) to disperse the SOx over a broad area.

This same discussion applies to other inorganic substances in typical waste streams, such as chlorine, sodium, potassium, phosphorus and silica in the sense that burner design cannot inhibit the presence of these elements in flue gas.

Burner testing

The following examples are primary reasons why factory testing of thermal oxidiser burners prior to shipment is not a routine practice:

- While a mixture of gases can easily be made to produce a stream that will be very close to the expected fuel for a fired heater burner test, it is rarely feasible to produce a waste stream that approximates what the thermal oxidiser will typically burn. This is usually due to the high volume and/or unusual nature of the waste components
- If it is possible to produce a stream that is comparable to the expected waste, it is likely that the components of the test waste will require a special environmental permit. Most projects do not allow for the time and expense required to obtain such a permit and most test facilities are not willing or able to pursue this type of permit
- If it is possible to prepare a comparable waste stream and a permit can be obtained, it may not be feasible to heat the stream to the expected operating temperature
- Thermal oxidiser burners are frequently too large to fit into an existing burner test furnace
- Thermal oxidiser burners are frequently too large to be fired at the available test facility fuel rate
- Most available test furnaces are designed to simulate the conditions of a fired heater. The behaviour of a thermal oxidiser burner in a fired heater will be quite different from the same burner in a refractory-lined thermal oxidiser chamber. As discussed previously, the NOx emissions will certainly be different, as will the flame length and almost any other combustion performance measurement that may be of interest
- It is usually not feasible to test the thermal oxidiser burner in its combustion chamber due to the cost of a field simulation test setup.

Despite the above limitations, many thermal oxidiser manufacturers will provide an optional burner flame stability test using fuel oil, natural gas or propane fuel gas (subject to fuel capacity and test furnace size constraints), but only if the customer specifically requires the test. However, this type of limited test represents significant additional cost and provides very little useful information.

Calculation of required supplemental fuel

The proliferation of chemical process simulation software has provided an increase in productivity for engineers around the globe. However, like all software, it has its limitations. It is common among combustion engineers to speak of “exothermic” and “endothermic” streams. These are rather loose definitions: exothermic streams are generally considered to be ones that require no supplemental fuel to reach the oxidiser operating temperature when burned. Conversely, endothermic streams require supplemental fuel. The danger is assuming the result from the process simulator reactor module will accurately calculate the required supplemental fuel. For example, it is common in the carbon black industry to burn tail gas that is roughly:

Component	**Vol%**
Nitrogen	40
Water vapour	40
Carbon monoxide	10
Hydrogen	10
Temperature	450°F
Lower heating value	60 Btu/scf

Now, let us compare that to the following hypothetical vent gas stream:

Component	**Vol%**
Methane	10
Carbon monoxide	10
Carbon dioxide	80
Temperature	100°F
Lower heating value	123 Btu/scf

If the combustion of each of these streams is simulated using 25% excess air at 982°C (1800°F) operating temperature, neither requires supplemental fuel. However, experience shows that the hypothetical vent gas stream requires supplemental fuel, whereas carbon black tail gas does not. Please note that this is the case even though the hypothetical waste is twice the heating value of carbon black tail gas. Intuitively, tail gas combustion is self-sustaining due to high feed temperature and hydrogen content (see Figure 3). It is important to note that there is not a mathematical formula available that will reliably predict the required fuel for many exothermic waste streams. Simply put, there is no substitute for experience in thermal oxidiser design.

Mechanical design pressure

Many engineers are uncomfortable with the concept of a high-pressure stream flowing to a system that operates at relatively low pressure. This apprehension is quite understandable because thermal oxidisers (and flares) are often the only process in the plant that has an unobstructed flow path to atmosphere. Typically, there are no block valves to obstruct the flow downstream of the burner. Pressure that can exist downstream of the valve separating high pressure from the incineration system is the sum of the pressure drop of the equipment/piping downstream of the valve. To get a sense of the pressure drop of typical thermal oxidiser system equipment, see Table 1.

Waste streams are often injected into the burner. Typical required oxidiser injection point pressure drops for various streams are shown in Table 2.

The reason these pressures are listed in a separate table is that the "system" we are describing actually begins downstream of these injection points. The pressure in the pipe feeding these injection points must be greater than the pressure drop of the injection point. Downstream of this point, the pressure is dictated by the downstream equipment pressure drops. Thus, the burner housing and combustion chamber in which a hydrocarbon liquid is being burned does not need to be designed for 10 barg, although the pipe that feeds the burner does need to be.

Typical pressure drop in a thermal oxidiser system

Equipment	Pressure drop (mbar)
Oxidiser vessel	1 to 3
Water tube boiler	2.5 to 20
Fire tube boiler	5 to 20
Superheater	1 to 7
Economiser	1 to 7
Combustion air preheater	7 to 40
Waste gas preheater	7 to 50
Baghouse (particulate filter)	5 to 20
Water spray quench	5 to 10
Submerged quench	40 to 150
Venturi scrubber	20 to 70
Packed column scrubber	10 to 25
Acid gas absorber	10 to 25
Dry electrostatic precipitator	1 to 7
Wet electrostatic precipitator	1 to 7
Vent stack	Usually 0

Table 1

Theoretically, it is possible to exceed the maximum expected operating pressure in cases of explosion (a rare and usually avoidable event), vastly higher than expected waste vapour stream flow or blockage of the flue gas path (due to fouling, for example). A safety and control system designed by any reasonable standard should be in place to prevent these scenarios. However, in the unhappy event that flue gas pressure drop does increase without the intervention of instrumentation, it is much more likely that excess pressure will be relieved through the vent stack exit or through the combustion air fan housing than oxidiser system over-pressurisation occurring.

Required injection point pressure drop

Stream	Pressure drop (bar)
Aqueous liquid	10 to 12
Hydrocarbon liquid	10 to 12
Exothermic vapour	1 to 0.1
Endothermic vapour	0.01 to 0.3

Table 2

Conclusion

The misconceptions discussed regarding thermal oxidiser design are often found to be pervasive throughout the process industries. Thermal oxidisers and fired heaters differ from each other in terms of purpose, designed function, NOx/SOx generation, emissions control and designed operating pressure. It is important to understand these differences to ensure the design of a robust system that meets project and operational requirements.

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