CONTROL OF EMISSIONS FROM GLYCOL DEHYDRATORS

C. Richard Sivalls, P.E.
Sivalls, Inc.
Odessa, Texas

ABSTRACT

Recent changes in the federal and state clean air laws and regulations will affect the operation of glycol dehydration units used by the oil and gas industry to remove water vapor from natural gas. These laws and regulations will limit the amount of aromatic hydrocarbons such as benzene, toluene, ethyl benzene, and xylene (BTEX) and volatile organic compounds (VOC's) that may be emitted into the air from the glycol regenerator still vent. This paper will present an overview of the new laws and regulations as well as process control systems that may be used to control and reduce the BTEX and VOC emissions from dehydrations units. Flares, incineration units, aerial coolers, recycle units, and the efficient R-BTEX process will be covered.

AIR REGULATIONS

The amendments to the federal Clean Air Act(CAA) passed in 1990 will significantly impact many glycol dehydration units that are now operating or are going to be installed in the United States. There are two major points in the laws that must be considered:[1]

1. Natural gas facilities that come under the requirements of the new standards and regulations will have to be permitted to be installed or to continue to operate.

2. Facilities that come under the standards will be required to install controls and to perform emissions monitoring to demonstrate compliance with the standards.

Section 112 as revised under Title III of the 1990 CAA Amendments regulates the emissions of 189 Hazardous Air Pollutants(HAP's) and requires the EPA to establish technology based standards for "major" and "area" sources. A "major" source is defined as any stationary source or group of sources within a contiguous area and under common control that emits more than 10 tons per year or more of any one HAP or a total of 25 tons per year or more of any combination of those listed HAP's.[2]

There is an exception to the definition of "major" for oil and gas exploration or production wells. Section 112(n)(4)(A) of the CAA states that emissions from an oil or gas exploration or production well (with associated equipment) and emissions from a pipeline compressor or pump station shall not be aggregated with emissions from other similar units, even if the units are in a contiguous area and under common control.

An "area" source is defined simply as any stationary source of HAP's that is not a "major" source. However, the CAA states that oil and gas production wells (with associated equipment) shall not be listed as an "area" source, except in a metropolitan statistical area or a consolidated metropolitan statistical area with a poplulation greater than one million; and even then, only if the EPA specifically determines that emissions from these wells present more than a negligible risk of adverse effects to public health.

Glycol dehydration units that emit more than 10 tons per year of any one of the listed HAP's or 25 tons per year of any combination of HAP's are subject to regulation under the CAA of 1990. This will include implementation of maximum achievable control technology(MACT) to control emissions.

In addition to regulation at the federal level, several states have been investigating standards for regulation of HAP's.[3]

Texas

The Texas Natural Resource Conservation Commission(TNRCC) has a Standard Exemption 66 which requires permits for units emitting more than 25 tons/yr HAP's. A proposed rule for the Houston/Galveston and Beaumont/Port Arthur area would specifically limit this and require 90% control efficiency for HAPs. They are also considering a tiered approach to require control of 80% up to 90% depending on the amount of HAP's emitted.

New Mexico

The New Mexico Environment Dept. has drafted a final regulation that specifically mentions glycol dehydrators. Generally it will follow the federal 10/25 tons/yr guidelines for HAP's.

Oklahoma

The Department of Environmental Quality(DEQ) has jusridiction only after lease custody transfer, or after the gas is sold by the producer. DEQ requires best available control techology(BACT) for units with HAP emissions above 1200 lb/yr. The Corporation Commission has authority before lease custody transfer but is unlikely, at this time, to regulate glycol dehydration units.

DEHYDRATION PROCESS

Glycol dehydration units using triethylene glycol (TEG) are widely used to remove water vapor from natural gas to prevent corrosion and hydrate formation in pipelines and downstream process equipment. A typical field dehydration unit is illustrated in Figure No. 1. The wet gas stream typically enters the unit through a inlet gas scrubber. Here, any free liquids as either hydrocarbons and/or water are removed from the gas stream. The gas then passes to a glycol/gas contactor where the gas flows upward through the vessel and it is contacted with triethylene glycol(TEG) flowing downward through the vessel. The glycol removes the water vapor from the gas by absorption. The gas exits the top of the contactor, passes down through a glycol/gas heat exchanger where it helps cool the reconcentrated glycol, and leaves the unit.

The glycol is reconcentrated by passing it from the bottom of the contactor to the regeneration portion of the unit. Typically it first flows through a particle filter, the glycol pump, a flash separator, a gylcol/glycol heat exchanger, and into the base of the stripping still mounted on top of the reboiler. In the reboiler, heat is applied to the glycol to drive out the water vapor and reconcentrate it to be used again. The dry glycol flows from the reboiler to the heat exchanger/surge tank where the pump can pick it up and put it back through the contactor to absorb more water from the gas.

BTEX and other VOC emissions from dehydration units result from the physical absorption of these compounds into the glycol. As water is removed from the gas in the contactor, TEG also absorbs hydrocarbons from the natural gas. All hydrocarbons are soluble in TEG to a limited extent, but TEG has a particularly high affinity for the BTEX compounds.

Many of the lighter hydrocarbons are separated from the glycol in the flash separator which typically operates at less than 100 psig and up to 200°F depending on where the glycol/glycol heat exchanger is placed in the system. However, because the atmospheric boiling points of the BTEX compounds range from 176°F to 291°F, relatively little of these are removed in the flash separator. The BTEX and other VOC's not removed from the glycol in the flash separator are emitted to the atmosphere with the water vapor when the glycol is regenerated using the heat in the reboiler.

The water vapor boiled and stripped out of the glycol exits the top of the stripping still vent at atmospheric pressure and is normally vented to the atmosphere. Also, vented are any BTEX compounds and VOC compounds that have been picked up by the glycol when it contacted the gas in the glycol/gas contactor. In addition, if any stripping gas must be used to achieve a high concentration of dry glycol, then this is also vented with the water from the stripping still. The glycol/glycol powered pump, as illustrated, will also use a small amount of gas to provide power for the pump. This gas will flow with the glycol to the regeneration phase and be released with the vapors from the stripping still vent. However, if a glycol flash tank or separator is used, a great portion of the pump gas and some of the gas absorbed in the glycol can be separated from the glycol and used for fuel and instrument gas. This accounts for a significant reduction in the vapors released to the atmosphere from the stripping still. Most of the BTEX compounds absorbed in the glycol will not be released until the glycol is heated in the reboiler and therefore causes the BTEX emission problem associated with the glycol dehydration units.

EMISSION CONTROL PROCESSES

Dehydration Operation

One of the first things that should be discussed in dehydrator emission control processes is the efficient and proper operation of the glycol dehydrator itself. A flash separator should be installed if the unit does not already have one. It should be operated at the lowest pressure and highest temperature possible, within the the other operating constraints of the system. This will maximize the removal of BTEX and other VOC's from the glycol in the flash separator. Although a flash separator does not remove a large portion of the BTEX compounds, some removal may be sufficient for units that have BTEX emissions close to a regulatory de minimis level. Also removal of light VOC's from the glycol in the flash separator will maximize the BTEX recovery efficiency of condenser type control processes that are applied to the still vent vapors.

If either stripping gas or a supplemental stripping column is used with the reboiler to achieve maximum reconcentration of the regenerated glycol, this stripping gas should be regulated and metered. Only the proper amount of stripping gas should be used and this will reduce the amount of VOC's coming out of the stripping still vent with the water vapor.

The reboiler fuel gas controls should be regulated to provide for steady firing of the reboiler. Fluctuating firing will cause upsets in the amount of water vapor passing out of the stripping still vent. A constant flow of the glycol through the unit should be maintained to achieve steady firing in the reboiler. All instruments and controls should be properly adjusted for the smoothest and consistent flow of the process. Only the minimum amount of glycol required should be circulated and the lowest temperature possible should be maintained in the reboiler within the requirements to dehydrate the gas in the contactor. All of these considerations will reduce the emissions from the stripping still vent to a minimum.

Flare Stack Units

The flare stack is one of the simplest forms of emission control processes. A schematic drawing of a typical unit is shown in Figure No. 2. It consists of an elevated flare which attempts to burn all of the vapor products emitted from the stripping still of a glycol dehyration unit. Usually a small scrubber is installed at the based of the flare, as shown, to catch any liquid carry over or process upsets that may occur within the dehydration system. Little or no electrical power is required depending on the control system utilized on the flare stack unit. However, supplemental fuel gas and a constant pilot flame is required since the vapor products from the stipping still may not support continuous combustion. Another drawback in the flare stack unit is that a visible flame and oftentimes smoke is produced. This may or may not be acceptable to the local regulatory authorities and any nearby residents. There is little way to assure that all of the products from the stripping still are completely oxidized since the combustion usually takes place outside of the flare stack unit.

Incineration Units

The incineration process utilizes a controlled combustion which oxidizes the emissions and exhausts them to the atmosphere as normal combustion products. The incineration process can achieve a high level of emission control to assure compliance with environmental regulations. There is no visible flame or smoke from a properly adjusted incineration unit. Since complete destruction of all water vapor and other compounds is made in the process, there are no liquids to be disposed of in the system. A typical incineration unit is illustrated in Figure No. 3. The still overhead vapor stream passes through a small separator and then into the combustion chamber area of the incinerator. The separator is provided to prevent the loss of glycol should any unexpected upset in the regeneration system occur and discharge any glycol in the still overhead vent stream.

Supplemental fuel gas will be required in the incineration process to maintain a steady combustion in the chamber. Since the water vapor from the glycol regeneration process passes through the incineration system, considerable amount of fuel gas may be required depending on the amount of water removed in the process. The incineration stack portion of the unit must be lined with refractory material due to the high temperatures maintained in the unit. Also, electrical power is required to operate the controls and instrumentation in the system. A thermocouple is usually installed above the combustion chamber portion of the unit to assure a minimum temperature and that complete combustion occurs. This will assure that there are no unburned products exiting the top of the incineration unit. These units can be expensive due to the physical size and the refractory lining required.

Condenser Units

Another control option utilizes a cooling medium to condense the overhead stream from the stripping still. A schematic flow diagram of a typical condenser type control unit is illustated in Figure No. 4. The condensing medium may be the rich glycol stream from the contactor, prior to regeneration, or a water stream if there is one available. If the rich glycol stream is used, remember the minimum rich glycol temperature available for condensing is dependent upon the natural gas temperature in the contactor which is typically at or above ambient dry bulb temperatures. Normal approach temperatures for liquid cooled exchangers are on the order of at least 20°F above the cooling medium. Also there may not be enough glycol flow, if that is what is used, to satisfy proper heat exchanger design. The outlet from a condenser type unit will be uncondensed vapors, a water stream with hydrocarbons in it (up to 1000 mg/L), and possibly a liquid hydrocarbon stream. All that is not condensed will still be vented to the atmosphere. Pumps may be required, as shown, to transfer the liquids to a storage system.

Aerial Cooler - Condenser Units

Condensers with forced draft aerial coolers are another scheme used to control the emissions from glycol dehydration units. The design is relatively simple and the cost can be competitive with other types such as incineration units. However, the outlet condenser operating temperature will be on the order of 20°F above the ambient (dry bulb) air temperature. This may or may not condense the required amount of BTEX compounds out of the still overhead stream. The aerial cooler type unit will also produce a water stream with approximately 1000 mg/L of hydrocarbons in it. A typical aerial condenser unit is illusted in Figure No. 5. In this process a forced draft aerial cooler is used to condense the maximum amount of vapors possible from the stipping still vent. The condensed products are removed from the uncondensed products in a three phase separator downstream from the aerial cooler. The liquid water and any liquid hydrocarbons must be removed and disposed of in a manner satisfactory to the regulatory authorities. Since the separator operates at atmospheric pressure and at ground level, pumps (as shown) or some other type of transfer system may have to be used to pump the liquids from the unit. The uncondensed vapors may be released to the atmosphere if this is acceptable to the environmental jurisdiction or may be recycled and burned in the firebox of the reboiler. Proper controls and safeguards must be used if these products are to be burned in conjunction with the fuel gas in the reboiler. If may be necessary to compress these products to sufficient pressure before they are mixed with the fuel gas in the reboiler. Also, it may be that more hydrocarbons are released from the aerial cooler unit than is required by the reboiler firebox heat demand. The excess then must be disposed of in another manner.

The forced draft aerial cooler process will require more electrical power than other types of emission control technology due to the power required for the large motor driving the fan in the unit. Also, electrical power may be required if the uncondensed gas has to be compressed before it can be used or disposed of and power is required if pumps are necessary to transfer the liquids from the unit.

R-BTEX™ PROCESS

The patented R-BTEX™ process[4] is shown in Figure No. 6. The R-BTEX™ technology was developed by Radian Corporation and Sivalls, Inc. with assistance from the Gas Research Institute. The dehydrator still vent vapors first pass through an air cooled heat exchanger in which most of the water and some of the hydrocarbons are condensed. The partially condensed stream then goes to a water cooled heat exchanger where most of the remaining hyrocarbon vapors are condensed. Since the process outlet temperature is typically at or below the ambient(dry bulb) air temperature, this maximizes the condensation and recovery of hydrocarbons. The condensed, three phase stream flows to a small separator, where it is partioned into noncondensable vapor, hydrocarbon liquids, and water. The small amount of noncondensable gas can be compressed, burned, or vented depending on the local regulatory requirements. The hydrocarbon layer is decanted and stored for sale.

The condensed water is combined with water from the bottom of the cooling tower and used as the coolant in the water cooled exchanger. The water is then passed through a packed tower where it is cooled by evaporation and any hydrocarbons are stripped by the air flow through the tower. Air stripping of the cooling water results in hydrocarbon concentrations in the water that are below the offshore oil and grease dishcarge limit (29 mg/L) for water from oil and gas production.

Utility requirements for the R-BTEX™ process are minimal. Water may be supplied at process startup or can be recovered initially by running only the air cooled exchanger. A small amount of electrical power is required for the cooling tower fan which uses a much smaller motor than a typical forced draft condenser unit and for the cooling water circulation pump. Pumps may also be required to transfer the liquids from the unit.

The key feature of the R-BTEX™ process that distinguishes it from other condensation processes is that cooling water is generated within the process. The water is cooled to below ambient temperature(dry bulb) by evaporating water across the cooling tower packing. The cooling water temperature will typically approach within a few degrees of the wet bulb temperature which is below the normal ambient temperature(dry bulb), except at 100% relative humidity. Field tests on the R-BTEX™ have resulted in a control efficiency of 95 to 99% on the BTEX emissions coming from the stripping still vent. Control efficiency on the VOC emissions was in the range of 93 to 99%.

Other advantages of the R-BTEX™ process include:

1. The potential for a short payout period because of the high liquid hydrocarbon recovery which has a market value.
2. A relatively "clean" blowdown water stream than can meet offshore discharge regulations.

CONCLUSIONS

The new federal and upcoming state air quality requlations will require emission controls on many of the glycol dehydration units operating in the United States. Improved and optimized operation of dehydration units will minimize the emissions coming from these processes. However, if environmental controls are required, the units will have to be permitted with the requlatory authorities and control systems will have to be installed. Additionally the control systems will have to be tested and monitored to prove that they are working.

REFERENCES

1. Coerr, Stanton; "Enhanced Monitoring and Operating Permit Requirements for Natural Gas Facilities Subject to Existing MACT Standards; 1994 Gas Research Institute, Glycol Dehydrator/Gas Processing Air Toxics Conference.
2. Sivalls, C. Richard, Rueter, Curtis O., Fisher, Kevin S. and Gamez, Jorge P.; "The R-BTEX™ Process for Migigating Air Emissions from Glycol Dehydrators", 1994 Gas Research Institute, Glycol Dehydrator/Gas Processing Air Toxics Conference.

3. Radian Corporation, Austin, Texas; Communications with Gas Research Institute, July 1994.

4. U.S. Patent No. 5,209,762, "Method and System for Controlling Emissions from Glycol Dehyrators", Lowell, Dated May 11, 1993.

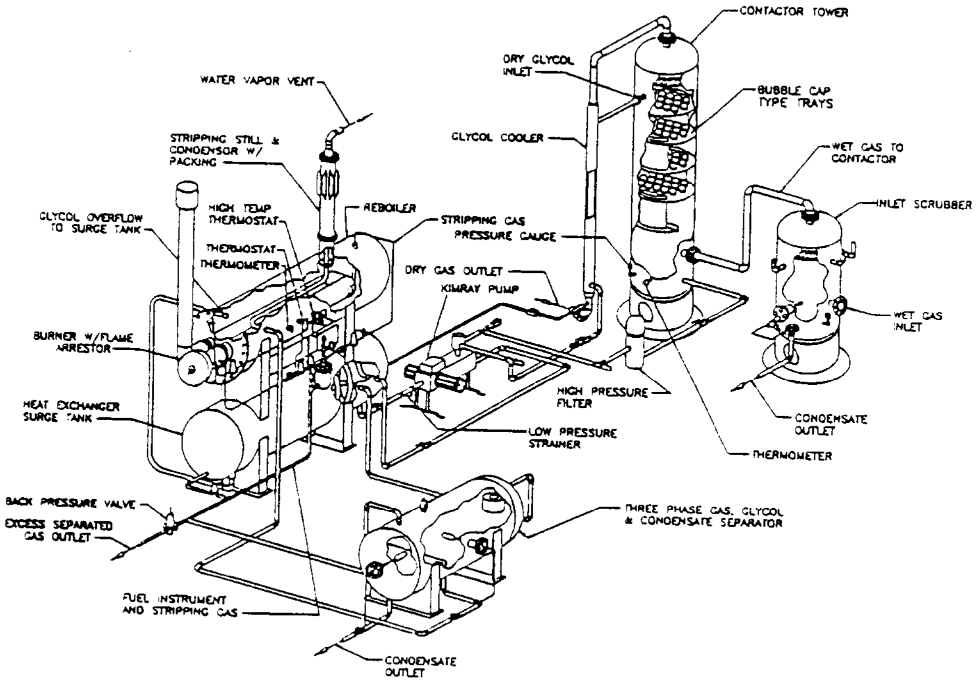

Figure 1 - Dehydration Operation

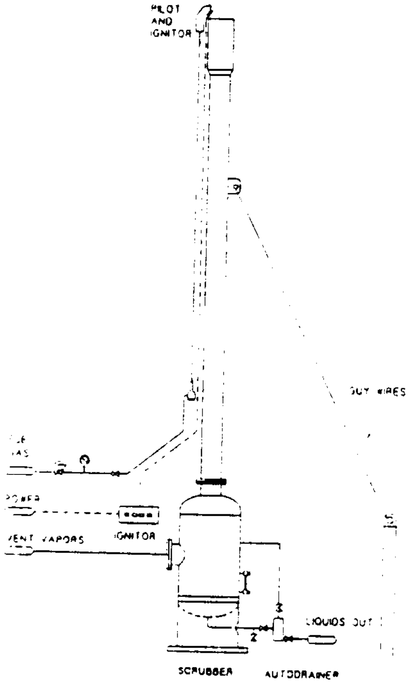

Figure 2 - Flare Stack Unit

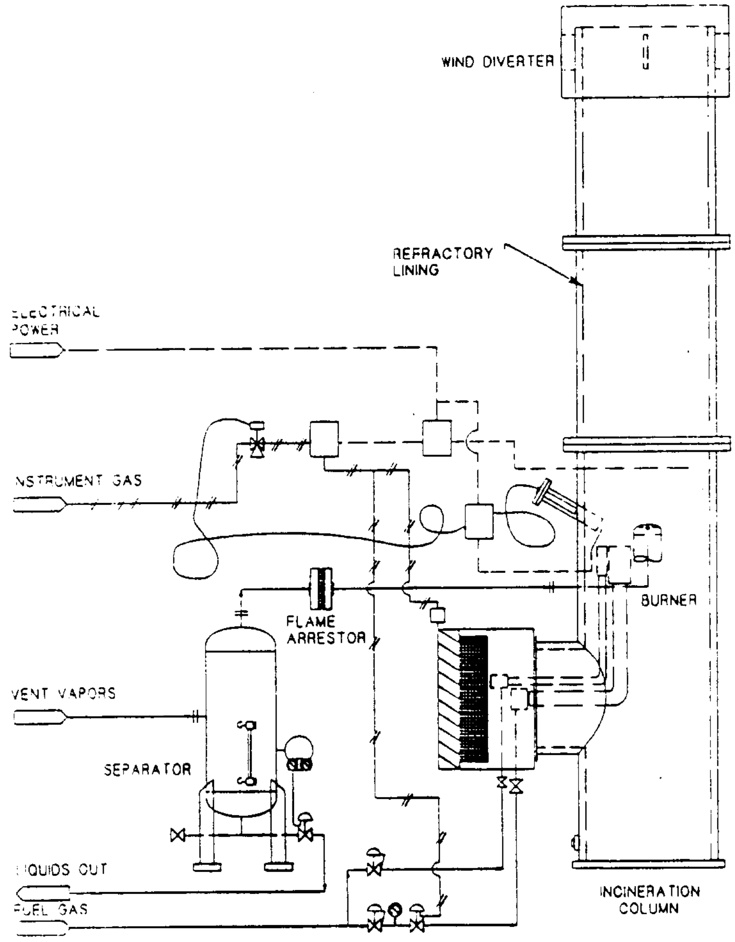

Figure 3 - Incineration Unit

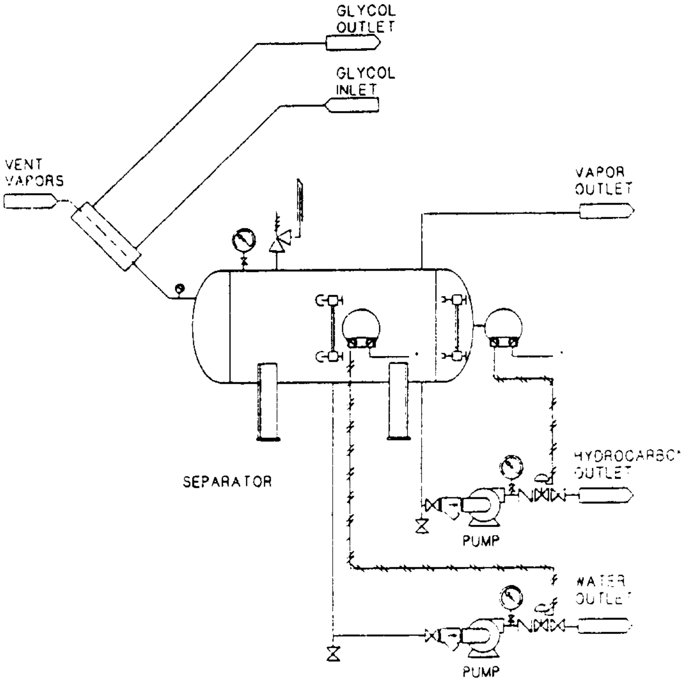

Figure 4 - Condenser Unit

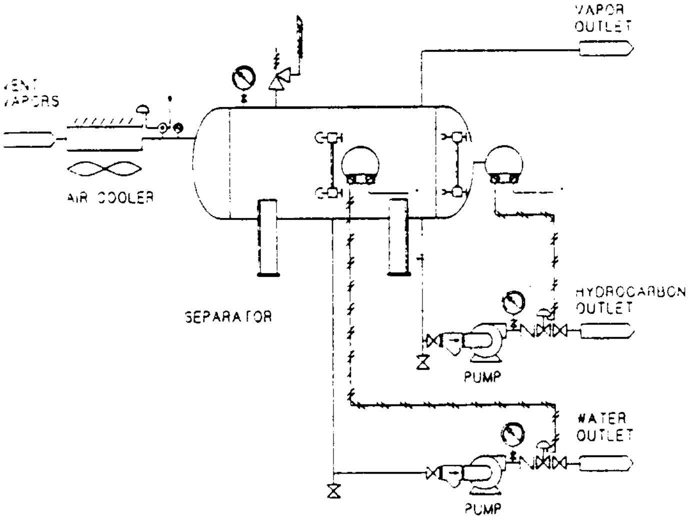

Figure 5 - Aerial Cooler-Condenser Unit

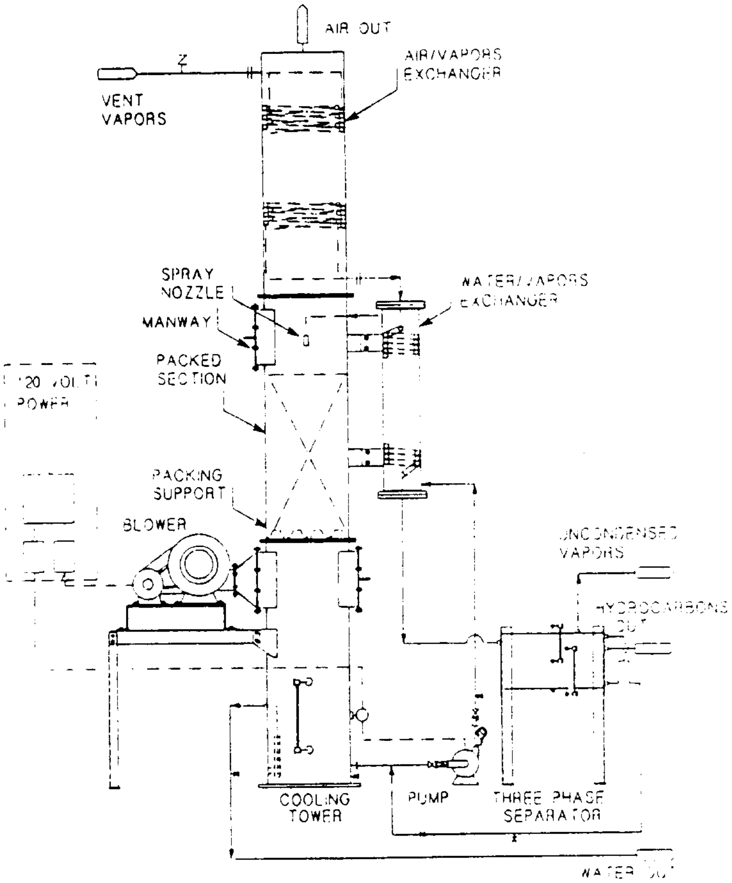

Figure 6 - R-BTEX™ Process