ACD Invested in Simulation Driven Design

Simulation-driven design enables ACD to reinterpret the process of design, while offering our customers tested products with confidence in design and evidence of performance. Unlike the past, when each design required a prototype for testing, simulation takes design to a whole other level. Simulation-driven design is defined as *"a design process where decisions related to the behavior and the performance of the design in all major phases of the process are significantly supported by computer-based product modelling and simulation"*.

ACD's integrated state-of-the-art simulation tools and solutions help to explain performance trade-offs at an incredible level of detail. This enables us to analyze a variety of conditions up front, review results and fine-tune the design prior to the full-scale prototyping and testing. Simulation-driven design gives us the ability to resolve potential issues before we put them in the design, thus preventing expensive field failures. The result is a better end product for our customers.

What are the benefits? Simulation provides several key benefits: Improving/increasing product quality, resulting in a reduced risk of failures and warranty issues; simultaneously improving the bottom line through reduced product and labor costs.

a) Timescales – ACD recognizes the power of building, testing and verifying their products using a virtual prototype rather than a physical prototype. This is more cost effective and offers lower risk, which in turn translates to reduced cycle times.

b) Evidence of Performance – Customers require evidence of performance and compliance to a variety of industry codes and standards. It is easier and more accurate to perform simulations rather than build the prototype and do destructive testing.

c) Failure Root Cause Analysis – In cases where you have a failed part, simulation allows us to analyze it and determine what the root cause of the failure was. Identifying the root cause of the failure allows for design modifications that can be implemented quickly and thus reduces equipment downtime.

d) Confidence in Design – Traditional approach to design is to perform hand calculations and sketch something out. There is little-to-no confidence in the design; the confidence comes from testing. Our state-of-the-art software tells us more about the design and provides that confidence without the time and expense of extensive physical testing or oversimplified calculations.

Simulation Software Applications

The various software tools available and in use at ACD for design simulations are:

Sizing and Selection Tools

- TESS: TurboExpander Sizing and Simulation – Our modern, networked, graphical software system designed and built in-house to support rapid selection and sizing of turboexpanders.

- SPAIX: Centrifugal & Reciprocating Pump selection and configuration – This software includes a rich database of specifications and performance data that helps us select the right pump for our end user.

Aerodynamic Design Codes

As a provider of turbomachinery solutions, ACD's competence lies in our skill and ability to design impellers customized to end user needs. The following aerodynamic sizing tools allow design and rapid analysis of the flow through the impellers.

- Aerodynamic 1D Sizing Tools ("Meanline" Analysis)
  - Vista Tools in Ansys - Includes design software such as CCD (Centrifugal Compressor Design), CPD (Centrifugal Pump Design), RTD (Radial Turbine Design)
  - Concepts NREC Compal

- Blade Geometry Design
  - Ansys BladeGen and BladeEditor
  - Concepts NREC

- Aerodynamic 2D Rapid "ThroughFlow" Analysis
  - Concepts NREC Axcent

- Turbomachinery Specific Mesh Generation Tools
  - Ansys TurboGrid
  - Numeca AutoGrid5

- 3D CFD (Computational Fluid Dynamics) Analysis Software
  - Ansys CFX & Fluent
  - Numeca Fine/Turbo

Structural Analysis Tools

- Mechanical Analysis - Static Structural, Modal, Thermal
  - Ansys Mechanical
  - SolidWorks Simulation

- Rotordynamics
  - XLRotor - For simulation of rotor bearing system dynamics.

Testing

- Experimental Modal Analysis (EMA) – To do full modal analysis on impellers and measure FEA-computed frequencies and mode shapes.
  - Data Physics Dynamic Signal Analyzer (DSA)
  - Vibrant Technology MeScope

- Labview 'Turbo Test' Software – Specialized software for cryogenic performance testing of compressors and expanders.

Computing Hardware

To support and run the simulation software, we have a full contingent of dedicated workstations for High Performance Computing (HPC). The computers are complete with high speed processors, RAM and storage capabilities and have been specifically tailored for CFD and FEA applications.

Examples of Simulation Driven Design

Impeller Modal Analysis

We at ACD perform FEA modal analysis on impellers to characterize impeller natural frequencies. The use of Campbell and interference diagrams, as well as animated mode shapes from FEA helps to visualize the potentially dangerous interactions of various impeller mode shapes and sources of excitation. The frequency analysis helps ACD avoid vibration-based failures by modifying geometry of the impeller hub and back disk including designing shrouded impeller if needed. All the geometry modification can be managed during the initial design phase thus avoiding costly rework and rejection after manufacturing and testing. After the impeller is manufactured, we perform full experimental modal analysis and our experience has shown very good correlation to analytical results.
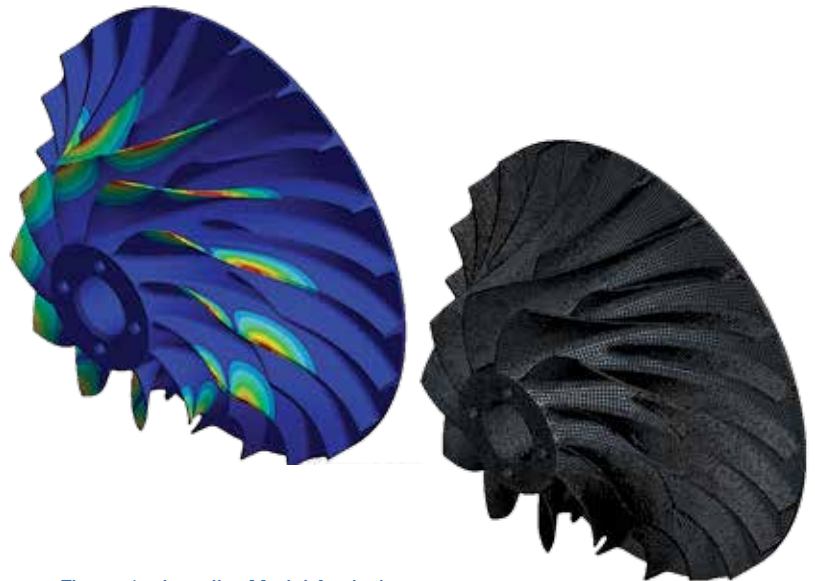

Figure 1 - Impeller Modal Analysis

Aerodynamic Blade Design and CFD analysis

Figure 2 shows a compressor blade design in Bladegen. This in an example of a development effort that ACD undertook to improve impeller efficiency. Extensive 3-D Computational Fluid Dynamic (CFD) analysis was done on the existing wheel design to characterize the flow field. Several blade profiles were generated using the commercial codes Concepts/NREC and ANSYS BladeModeler. The CFD analysis was done using Numeca Fine/Turbo software with identical mesh settings for all designs and subsequent mesh refinements were done to get mesh independent results on the chosen design. CFD was primarily used to rank the designs based on stage total to total efficiency.
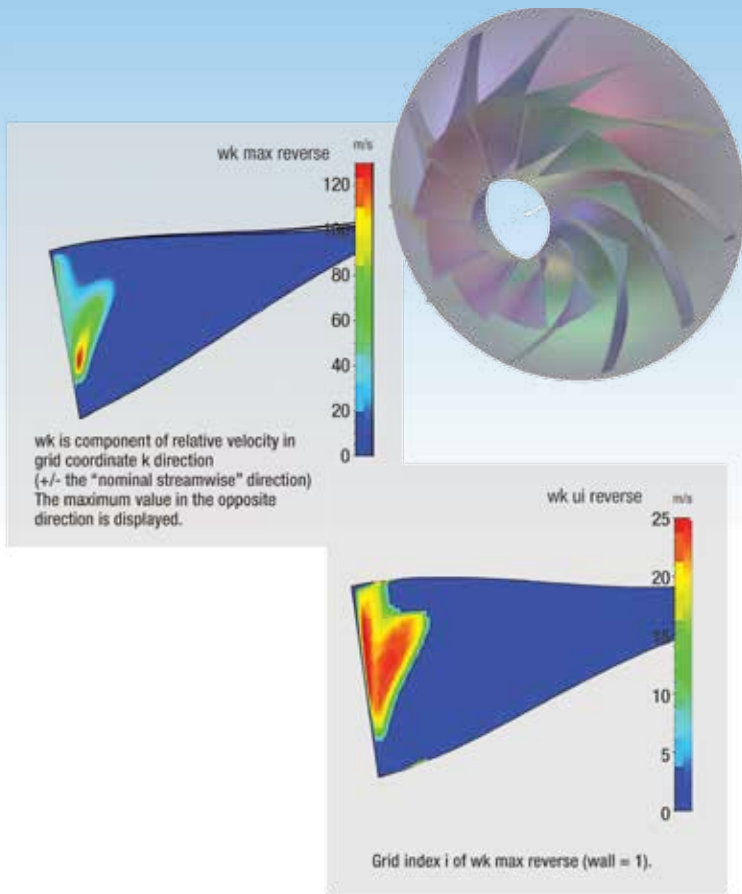
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Figure 2 - Compressor Blade Design

Figure 3 - Pump Impeller Design - New Product Development

Frictional Contact Analysis

Our FEA capabilities allow us to design a part around the results of the Frictional Contact Analysis. One such example shown in Figure 4 is of an impulse liquid turbine that ACD designs. Because of the cyclic nature of the load, the impeller shroud came loose. FEA was used in failure root cause analysis and the design was modified to prevent such failure
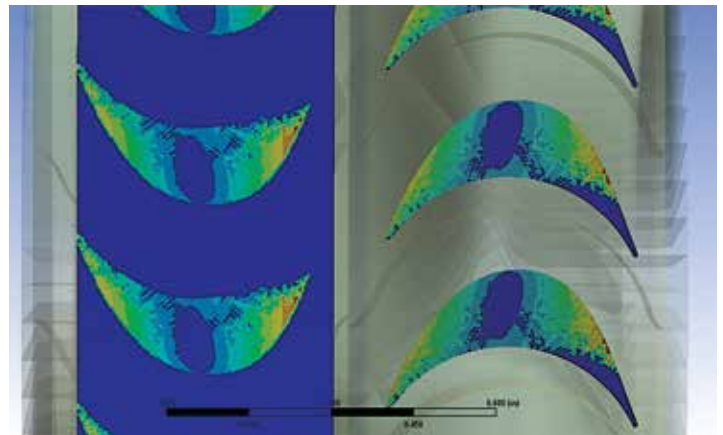

Figure 4 - Frictional Contact Analysis

Professional Analytical Staff

In addition to the investment that ACD made in simulation tools and methods development, we have an experienced engineering staff with years of experience in turbomachinery design and analysis. Without their expert knowledge it would be very difficult to understand and evaluate designs and leverage the capabilities of the software.

Simulation driven design combined with robust design practices, experienced staff and powerful high-performance computing enables ACD engineers to predict performance and solve product design challenges faster than ever with a high degree of confidence.

For more information, visit acdllc.com.

New Product Development - Pump Impeller Design and CFD

ACD's new product development department's mission is to constantly re-invent the company's products to maintain leadership in the ever-changing market. A simulation-driven product development approach helps in order to bring different ideas to the table, work with them and take the best possible solution to move further into the testing phase, faster and more efficiently. While working to get a new line of centrifugal pumps for the LNG market, CFD is being used by ACD to sort out the best designs for the hydraulic components. The variations include changes in number of blades, blade angles, wrap angles, passage heights, and gulping and trimming component among other options. A design of experiment study can be set up for the impeller, diffuser and inducer designs using the CFD software to get the best stage performance for the application. These designs can then be manufactured and tested in real-time to experimentally verify and approve for production. Using CFD has enabled exploration of ideas as a faster and more effective way of proving those designs before manufacturing and testing each design. Since there is a decrease in the number of physical prototypes made, there is a significant reduction in manufacturing and development costs.

Pilot Programs and Open Loop Natural Gas Liquefiers

The market for LNG as an alternate fuel is evolving. There is considerable discussion about LNG vs. CNG and the cost of converting from diesel. The use of Open-loop type liquefiers could mitigate risk. They are simple and significantly less costly than conventional closed-loop systems. Open-loop liquefiers are designed to convert clean natural gas into LNG using liquid nitrogen (LIN) as the refrigerant. The conversion ratio is somewhere between 1.2 to 1.5 gallons of LIN for each gallon of LNG produced. While this liquefier design may seem to be impractical at first due to the cost of LIN, it is a quick-on-stream solution at a fraction of the cost when compared to a larger mid-scale closed-loop liquefier. This advantage is beneficial when the primary target markets are pilot programs for introducing LNG to new users and where the risk and uncertainty can be mitigated with the low capital cost. Furthermore, the simple design and modularity of the open-loop plant makes it ideal to relocate after a market has been developed and a more permanent and efficient liquefaction solution employed.

The largest operating cost in an open-loop plant is the cost of LIN used to liquefy the incoming natural gas compared to electricity in the closed–loop system. A typical closed-loop merchant plant will produce around 100,000 gpd and consume between 0.7 – 0.8 KW/g LNG. Using average market price of $0.50/100 scf of LIN and $0.12/KWh for power, for the same capacity plant, LIN costs can easily exceed the power costs associated with a closed-loop system. However there are certain situations where producers have access to low-cost LIN and can more easily justify the higher operating costs of an open-loop plant. For example, where LIN is being vaporized for consumption as gas, an open-loop liquefier can be substituted for the vaporizer. Also, there are LNG producers that also produce LIN from their own air separation plant. In this case, a producer's LIN costs likely would be 30% less or more than if they had to purchase LIN from the market.

From a capital perspective, the open-loop plant is significantly less to install. The equipment in an open-loop liquefier consists only of a LIN tank, a dual LIN pump skid, and a Cold Box containing cryogenic heat exchange equipment. Unlike a closed-loop system, the open-loop plant has no refrigerant compressors or turbo-expander sets which would require medium voltage power (4160V) and cooling water. Only a small amount of low voltage power (480V) is required for the LIN pumps and controls. Given the simpler configuration, the open-loop plant can be on-stream as much as 6-12 months faster than a closed-loop plant. Therefore, though the operating costs can be much higher, the lower capital cost of an open-loop liquefier gives LNG producers a low capital cost option to quickly enter a risky market.

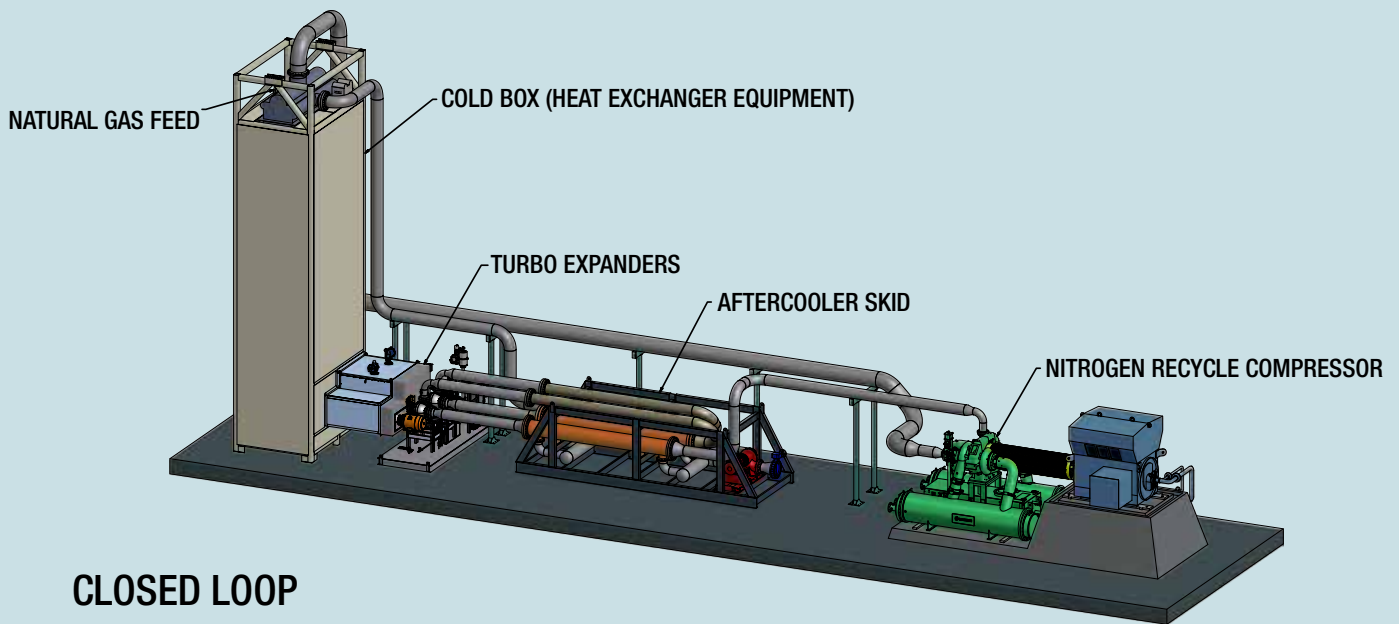*Cosmodyne Open-Loop Liquefier Installation*

Cosmodyne recently commissioned an open-loop liquefier which was installed to develop the high horsepower market in the area. The producer's plan is to install a larger closed-loop system in a few years and move the open-loop plant to other new markets.

In today's LNG market there is some hesitation to adopt LNG use because the supply network has not been fully developed. Yet, at the same time, producers have been slow to install capacity because adoption of LNG use has been slow to evolve. This specific quandary makes the small open-loop liquefier a good, low-risk option for producers to add capacity quickly and build up demand without having to commit to the high cost of purchasing and installing a permanent closed-loop system.
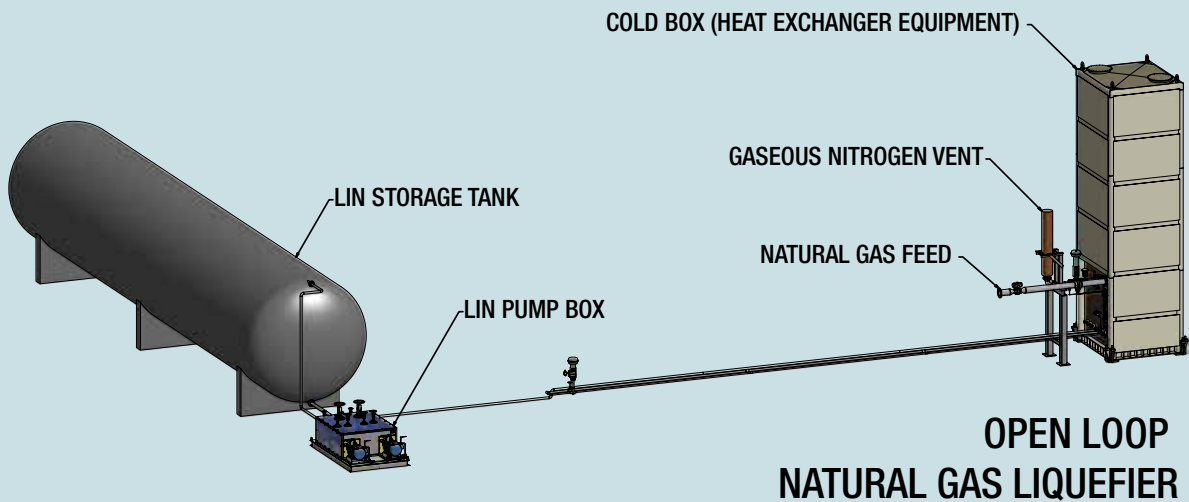
If you have any questions, please contact us at info@ cosmodyne.com.

Dual LIN Pump Skid On Cosmodyne's Open Loop Plant Installation

NATURAL GAS FEED

COLD BOX (HEAT EXCHANGER EQUIPMENT)

TURBO EXPANDERS

AFTERCOOLER SKID

NITROGEN RECYCLE COMPRESSOR

**CLOSED LOOP
NATURAL GAS LIQUEFIER**

COLD BOX (HEAT EXCHANGER EQUIPMENT)

GASEOUS NITROGEN VENT

NATURAL GAS FEED

LIN STORAGE TANK

LIN PUMP BOX

**OPEN LOOP
NATURAL GAS LIQUEFIER**

Odorization of Natural Gas

When it comes to vaporization of LNG, the last thing that comes to mind (and is often not even considered) is the odorization of the natural gas after its regasification. In this article, we will dive into the regulations of natural gas odorization, discussing when it is required, and how it is actually implemented.

When is Odorization Required?

Regulatory Background and Governing Specifications
Odorization is always nice to have, but when is it actually required and when can it be omitted? As more and more of the masses get into the LNG business, it's common practice for them to dive right into the spec labeled "NFPA59A" whenever a LNG question comes about. NFPA59A is the specification for "Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)" that was created by a committee of the American Gas Association. Since 1960, this document has been revised, resubmitted (to NFPA - National Fire and Protection Agency) and redistributed a number of times, making its last trip through the cycle in 2013. This document will yield nothing other than more questions when it comes to odorization… because simply put, the answer is not in there.

Although NFPA59A is the major specification that governs LNG systems, the odorization of natural gas takes place after the cryogenic liquid has been vaporized and has returned to its gaseous state. Answers regarding odorization will instead best be found in the Code of Federal Regulations (CFR); Title 49, Part 192, Section 625.

When and Where Odorization is Required
Per Title 49, Part 192, Section 625, odorization of natural gas is required when the natural gas is 'traversing in a distribution or transmission line and in a Class 3 or 4 location'.

Definitions
That tells us EXACTLY when we need to odorize natural gas… but what is a distribution line? What is a transmission line? And what exactly does Class 3 or 4 location mean?

Natural Gas Lines to be Considered and What They Are
There are three natural gas lines that come into consideration for odorization: gathering lines, transmission lines and distribution lines. Gathering lines are pipelines that are used to transport natural gas from a production site/facility to a main line (main line is a type of distribution line which is discussed below). Transmission lines are lines other than gathering lines that transport natural gas to a facility for storage or distribution, and operate at a hoop stress of 20% or more of specified minimum yield strength or transports gas within a storage facility. Distribution lines are pipelines other than gathering or transmissions lines. All these are defined in CFR Title 49, Part 192, Section **3**.

Class Locations and What They Are
When dealing with LNG the first thing that comes to mind when we hear the word "class" is hazardous zones. Class I Div. I, Class I Div. II, etc. Although important when dealing with system design, this is not what we're talking about when dealing with odorization. The classes referenced above (Class 3 and Class 4) are not hazardous zones but are instead population density classes. There are 4 class locations in total and these are defined in CFR Title 49, Part 192, Section 5. A class location unit is thus defined as "an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous one mile (1.6 kilometers) length of pipe. Classes 1 thru 4 are shown in the table below.

Location Class	Description
Class 1	i) An offshore area; ii) Any class location unit with 10 or less buildings intended for human occupancy per mile within 660' on either side of the pipeline.
Class 2	Ten to 46 buildings intended for human occupancy per mile within 660' on either side of the pipeline.
Class 3	i) Any class location unit with 46 or more buildings intended for human occupancy per mile within 660' on either side of the pipeline; or ii) An area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area (playground, recreation area, etc…) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12 month period.
Class 4	Any class location unit with 4 story buildings within 660' on either side of the pipeline are prevalent.

If you're in a Class 3 or Class 4 location and your natural gas is in a distribution line or a transmission pipeline, you will need to add an odorizer to your system. Outside of that, odorization is not required, though should be considered.

It is obvious that these regulations were designed for big natural gas pipelines traveling miles and miles. But Class 3 locations have two conditions; the second condition does not depend on the building density but rather the proximity of a building to the pipeline.

Exemptions for Odorization
There are a number of exemptions for odorization spelled out in CFR Title 49, Part 192, Section 625, which are listed below:

1) At least 50% of the length of the line downstream from a Class 3 or Class 4 location is in a Class 1 or Class 2 location.

2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;

    a. An underground storage facility:

    b. A gas processing plant;

    c. A gas dehydration plant; or

    d. An industrial plant using gas in a process where the presence of an odorant:

      i. Makes the end product unfit for the intended purpose

      ii. Reduces the activity of the catalyst, or

      iii. Reduces the percentage completion of a chemical reaction;

3) A lateral line which transports gas to a distribution center, at least 50% of the length of that line is in a Class 1 or Class 2 location; or

4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process. Note that this last exemption is not applicable to natural gas.

What do we put in, how do we put it in and how much do we use?

So now that we've discussed when and where to odorize natural gas, what is the odorant? How do we put the odorant in? And how much are we supposed to put in?

What do we put in?

When you use your stove at home and it doesn't light, you'll catch a little whiff of something that smells like bad eggs. That smell is the odorant that is put into the natural gas. It's actually a chemical called Mercaptan. This is the primary odorant used for odorizing natural gas. Note that there are other odorants used throughout the world (natural gas in America might not smell the same as natural gas in India), a list of typical odorants is below.

Types of Odorants

- Tert Butyl Mercaptan - The primary odorant used (egg-like smell)
- Tert butyl thiol
- Tetrahydrothiophene (THT)
- Ethanethiol (ethyl mercaptan)
- Dimethyl sulfide (DMS; garlic-like smell)
- Diethyl sulfide (DES)
- Methylethyl sulfide (MES)
- N-Propyl mercaptan (NPM)
- Isopropyl mercaptan (IPM)

How do we put it in?

There are a number of ways to put the odorant into the natural gas: bypass odorizing, wick odorizing, pulse bypass odorizing, drip odorizing, injection odorizing and bourdon tube odorizing. In this article we will focus on bypass mixing and injection mixing.

Bypass Mixing

Also called an Absorption Bypass Odorizer. Bypass Mixing Odorizers operate by taking a slip stream of the natural gas, running it through a container with odorant inside where the odorant is absorbed into the gas, then feeding it back into the main line. Typically, a pressure regulator between the bypass loop and the main line drives the natural gas through the odorizer, though this can be omitted with the use of a needle valve on the odorizer inlet line.

Liquid Injection Odorizer

In this process, the natural gas does not have to bypass anything or go through any tanks. The odorizer tank is hooked up with a pump. Odorant is pressurized and shot into the natural gas line. The amount is based on how much flow of natural gas is moving through the pipeline, measured with a flow meter.

These systems are much more complex than Bypass Mixing systems and involve more components and technology. They require a flow meter and a control panel or other forms of control. Being more complex, there's much more that can be monitored with these systems such as the level of odorizer left in the odorizer tank, amount of odorant being put into the natural gas, flow of natural gas, etc. This technology does come at a cost, and this type of system is considerably more expensive than a Bypass Mixing system.

How much do we put in?

This is a question that does not have a straightforward answer. If we look at the CFR Title 49, Part 192, Section 625, it states that enough odorant needs to be put into the natural gas where "a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell". One-fifth the explosive limit is 1% natural gas in the air (natural gas is combustible in the concentration range of 5-15% relative to air). But how do we define a person with a normal sense of smell, and how detectable is readily detectable? Also in CFR Title 49, Part 192, Section 625, it states that this is to be tested by the operator using a device that is capable of determining the level of gas in air at which the odor becomes readily detectable, and that a periodic "sniff" test is needed. As a general rule of thumb, 1 #/MMSCFH odorant to natural gas is the amount that should be added by the odorizer.

Even if your system is not in a high-populated, required area, you may still want to have an odorization system just as a safety factor for personnel working around the system. Per NFPA59A specifications, there are a lot of safety fall backs put into LNG systems including: hydrocarbon sensors, flame detectors, emergency shutdown protocols, fail safe equipment, etc, put there for safety reasons. But if something starts leaking downstream of all this equipment and odorant in the gas could be your last line of defense.

For more information, visit cryoquip.com.