THE USE OF COLD COMPRESSED NATURAL GAS (CCNG) TO INCREASE NATURAL GAS PIPELINE CAPACITY AND TO PROVIDE LOCAL STORAGE

Prepared for

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Section 1
TECHNOLOGY BACKGROUND

Natural gas storage is critical to the operation of natural gas markets, due to several factors, including the following:

- Natural gas is often found far from end-use markets, requiring storage facilities to act as "buffers" between production sites, liquid natural gas (LNG) import terminals, pipeline systems and customers. Storage facilities allow pipelines to be "refilled" as gas is consumed, improving the deliverability of the system.

- Production and pipeline systems operate on a full-time ratable basis. However, most demand for natural gas is uneven, with extreme peaks from a low base line. Storage systems buffer the discrepancy between production and demand, allowing excess production to flow into storage at off-peak periods and allowing high demand outflow at peak periods.

- "Line-packing," allows for the short-term use of pipelines as storage devices, but with limits on total capacity and storage time duration.

Natural gas at ambient temperatures and compressed to high pressures can be stored in spent gas fields and aquifers protected by faulted geological formations, in caverns formed in rock salt or other impermeable rock formations, or deeply chilled in aboveground LNG tanks. Salt caverns have been demonstrated as commercially viable storage vessels for a variety of ambient temperature gaseous and liquid hydrocarbons in many parts of the US, Canada and the rest of the world. It is a mature and well-understood technology but not available in California because of a lack of bedded salt formations.

The storage of natural gas, in various "vessels" (including line packing) can occur at a variety of temperatures and pressures, ranging from LNG as the densest form, to moderate pressure (warmer) gas storage as line packing in local pipelines, with moderately dense high-pressure (warmer) gas storage in spent gas fields and other underground geological formations. California has examples of several forms of storage, but not cavern storage or LNG in large tanks, such as found in "peakshaving" plants in Philadelphia, Baltimore, Brooklyn and elsewhere.

Most large-scale storage systems operate within "cycle constraints", where the inflow and outflow periods are limited by many factors. For example, most LNG peakshaving facilities are designed to store product during low-demand summer periods, and designed to send out NG during the winter heating season. Those models are less relevant, especially in California, as the demand for natural gas is at peak levels for many periods during the year, because natural gas is used for power production as well as for industrial uses and heating.

The storage of Cold Compressed Natural Gas (CCNG) fits within that spectrum of existing storage option but closer to LNG than the other options, including those that operate at very high pressures. This report will outline how smaller-scale LNG/CCNG production, storage and transport models mitigate the shortcomings of other storage options, allowing for faster inflow and outflow rates and offering distributive storage options that mitigate existing bottlenecks in the pipeline grid.

1A: WHAT IS CCNG?

A definition of CCNG must first define natural gas (NG). The following is offered:

> **"**Natural gas**"** is a fuel, consisting of a mixture of mostly methane gas, other hydrocarbon gasses and trace amounts of non-hydrocarbon gases, which is stored and transported at ambient temperatures and under a wide range of pressures.

CCNG is a denser and "cleaner" version of NG. It is stored at refrigerated temperatures and under pressure. If stored in a closed vessel, the steady state storage conditions of CCNG would be at temperatures of –150°F and colder and pressures of 700 psig and greater. Other CCNG storage and transport options (at warmer temperatures) will yield a lower density CCNG but still significantly denser than, for example, line-packing at standard pipeline temperatures, say, at +50°F, and at the maximum rated pressure of that pipeline.

Due to its cryogenic (deeply refrigerated) state, the chemical composition of CCNG needs to be slightly different then "pipeline-quality" NG. In order to avoid the forming of liquid products that would act like "slush" and "ice", CCNG needs to be dry, with a water content of less than 1.0 part per million (PPM) by volume, and it must contain less than 100 PPM of carbon dioxide (CO_2). Heavy hydrocarbons (ethane, propane, butane) need to be within the same limits as in LNG. Thus, CCNG (and LNG) contain 1% more energy than the equivalent volume (SCF) of pipeline NG, because water and CO_2 have been removed. That advantage stays with CCNG/LNG even when it is warmed back to normal pipeline conditions.

The clean-up process is well understood. It is a standard and routine part of all LNG plants, generally using molecular sieves and liquid separators. Resultant "off gas" is generally used as fuel for power production in on-site, gas-fired, direct-drive or generator-drive engines, or returned to the pipeline.

Expansion Energy LLC has the following CCNG-related patents pending:

> U.S. Patent Application No. 11/131,122, for **"Cold Compressed Natural Gas Storage and Transportation".**
>
> U.S. Patent Application No. 11/354,503, for a **"System and Method for Cold Recovery",** [which was granted on 12/16/08 as US Patent No. 7,464,557].

1B: CCNG PIPELINES

A CCNG pipeline consists of a suitable cryogenic metal, such as 9% nickel steel or certain grades of aluminum, or may consist of certain types of phenolics, Mircata, and other similar composites, or may be a combination of a liner and a casing, with tolerance for the –150°F and colder conditions and with a hoop strength that would sustain high-pressures. Because of the much-bigger density of CCNG, the diameter of the pipeline would be significantly smaller than that of standard lines with the same throughput. At smaller diameters, the wall thickness of the CCNG line would be thinner than the required wall thickness of standard, larger diameter lines with the same throughput.

In lined (concentric) configurations, the inner material may be pressure rated, providing all of the hoop strength, while the outer layer provides protection for the insulation system between the inner core and the outer shell. That insulation may be of several designs, including a low-grade vacuum between the liner and the shell. In other configurations, the inner liner may fit tight against the shell, with both providing hoop strength as well as a degree of insulation. In that model additional insulation, such as a micro-sphere wrapping, would further prevent heat gain to the flowing CCNG within.

The CCNG line, no matter what its configuration, would exhibit extremely low heat transfer characteristics. (On the other hand, for deployment in permafrost regions, the insulation would be limited so as to keep the surrounding conditions frozen, for the entire life of the pipeline, a significant advantage when compared to conventional NG pipelines.) The final leg of some CCNG lines would be designed with reduced insulation, or none at all, to allow the CCNG to arrive at the standard pipeline to which it is linked at a suitable, non-cryogenic temperature.

Short-distance CCNG lines may be especially cost effective. They may function well with no special insulation, relying on the frozen earth around it, (say, for a radius of four feet around the buried pipeline), where that “frost zone” acts to limit heat gain to the line, avoiding excess pressure drop, but allowing the CCNG to arrive at its not-too-distant destination at the proper temperature and pressure.

Such CCNG lines do not yet exist, but can be constructed with existing technologies. The extra cost of the suitable cryogenic tolerant material, and the extra cost of the insulation and the labor to install it, would be more then offset by the following:

- Much smaller diameters required to carry the equivalent “volume” of NG, as measured by its BTU content;
- Thinner, walls because of the smaller diameters;
- Much lower pipeline weight (the price of steel and aluminum is directly proportional to its weight);
- Reduced welding volumes, because of the smaller diameters and thinner wall thickness;
- Lower shipping costs because of the lower weight;
- Smaller trenches and rights of way.

The simplest configuration would consist of 9% nickel steel (or aluminum), field welded in appropriately sized segments, and field insulated, with very few take-off points, emphasizing the line’s “express delivery” nature, as compared to more “local” (warm CNG) lines. An excessive number of take offs will increase costs and heat gain. An optimal deployment will have a starting point and an end point, with no take offs except for pumping stations, and possibly, makeup cooling stations. As an express line, customers along the CCNG line would be supplied by existing standard lines that would, in turn, be supplied by the CCNG line at only one or two “transfer” points, much like a mass transit system with local and express elements.

Some designs may use a composite liner (for its cryogenic tolerance) surrounded by lower-grade nickel steel, acting as a “shell” (for its strength), or by a carbon fiber wrapping. The economic viability of each alternative would vary, and would reflect the total length of the CCNG line, its design capacity (throughput), the frequency of take-off points, the frequency of pumping and re-cooling stations, and other such factors.

More complex configurations, such as pipes within pipes in concentric configurations, separated by spacers, can transport CCNG in the inner pipe and CNG or a working fluid or a low-grade vacuum in the surrounding space. Such configurations may permit “cold recovery” regimes at the point of transfer from CCNG line to CNG line.

Each CCNG deployment possibility will need to evaluate the optimum balance between energy use and capital costs. The more complex configurations that achieve cold recovery will reduce the energy required to operate the system but will add to the capital costs. The simpler designs (such as the model with only the frozen earth as the insulation, discussed above) will require a much lower capital investment but may cost more to operate.

1C: WHY TRANSPORT AND/OR STORE CCNG LOCALLY?

- CCNG is much denser than warm NG, requiring smaller volumes for storing the same amount of energy, or allowing the same sized storage container to store more energy than any warm-NG storage or transport option.

- CCNG is a single phased state of NG, contained in pressure vessels that have a greater degree of tolerance for pressure build up then LNG containers, which produce “boil-off”.

- In a pipeline, CCNG is kept at pressure by periodic pumping stations, but moves along without the “slug flow” that is produced in LNG lines, where boil-off interferes with the flow of the liquid.

- Smaller (local) storage vessels are more easily developed than larger distant storage systems, reducing development time and bringing the storage capacity on line quicker.

- Local storage reduces the cost of transporting the stored NG to the end user and avoids bottlenecks in the pipeline delivery system.

- CCNG can be made from pipeline gas, from LNG, from stranded gas, at non-pipeline-quality gas fields, from “associated gas” (e.g. flared gas at oil wells) or from some combination of those sources.

- CCNG can be warmed and sent out in standard pipelines, or it can be “flashed” to make LNG.

- CCNG can be transported to and from a storage facility more efficiently in dedicated pipelines, for example, allowing imported LNG to be delivered inland in a high-density form.

- Of all the forms of stored and transported NG, CCNG requires the least energy input relative to the density achieved.

The most significant feature of CCNG is its density. Table 1, below, tabulates the densities of natural gas at various pressures and temperatures. The figures on the right hand side are conservative because they do not account for the increased heating value of the cryogenic products (when compared to pipeline NG), due to the absence of water and CO2.

Table 1: Density-Range For Pipeline-Quality Natural Gas

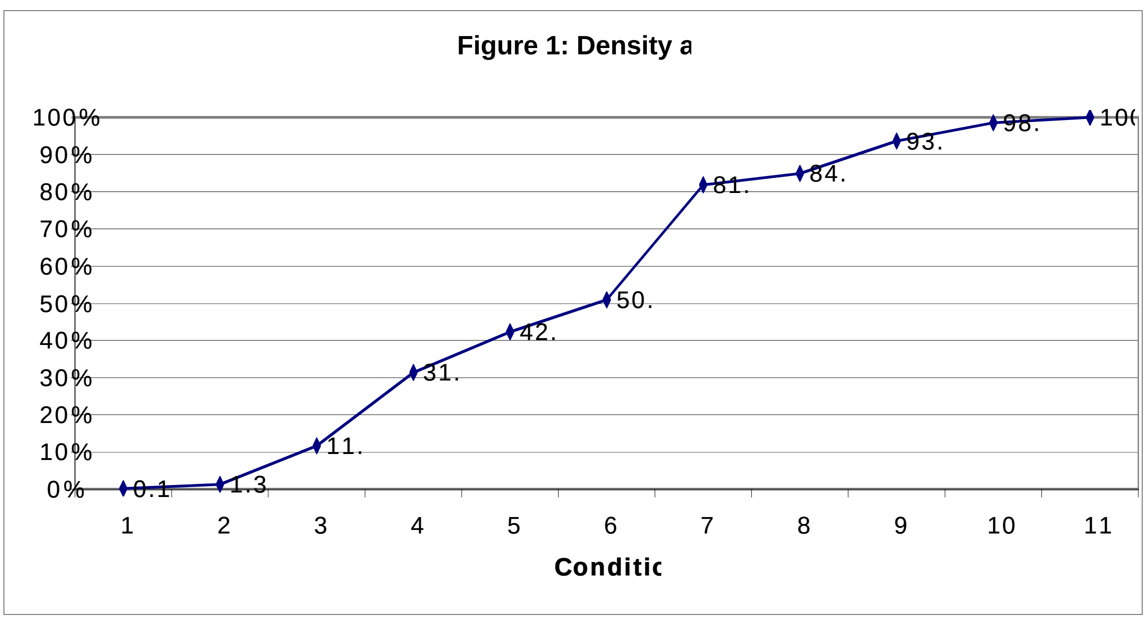
	1	2	3	**4**	5	6	**7**	**8**	**9**	**10**	**11**
USE		PIPELINE		**STORAGE**	VEHICLES		**STORAGE**				
CONDITION	Atmos.	Low-P.	High-P.	**High-P.**	High-P.	High-P.	**Low-P.**	**High-P.**	**Warm**	**Cold**	**Coldest**
NAME					CNG	L/CNG	**CCNG**	**CCNG**	**LNG**	**LNG**	**LNG**
Press. (psig)*	0	100	900	2,700	3,600	3,600	700	1,500	50	50	50
Temp. (Deg. F)	+70	+60	+60	+110	+100	+30	-150	-150	-225	-255	-260
Pounds/Cu. Ft.	0.045	0.35	3.1	**8.3**	11.2	13.5	**21.7**	**22.5**	**24.8**	**26.1**	**26.5**
Density of LNG	0.17%	1.32%	11.7%	**31.3%**	42.3%	50.9%	**81.9%**	**84.9%**	**93.6%**	**98.5%**	**100%**

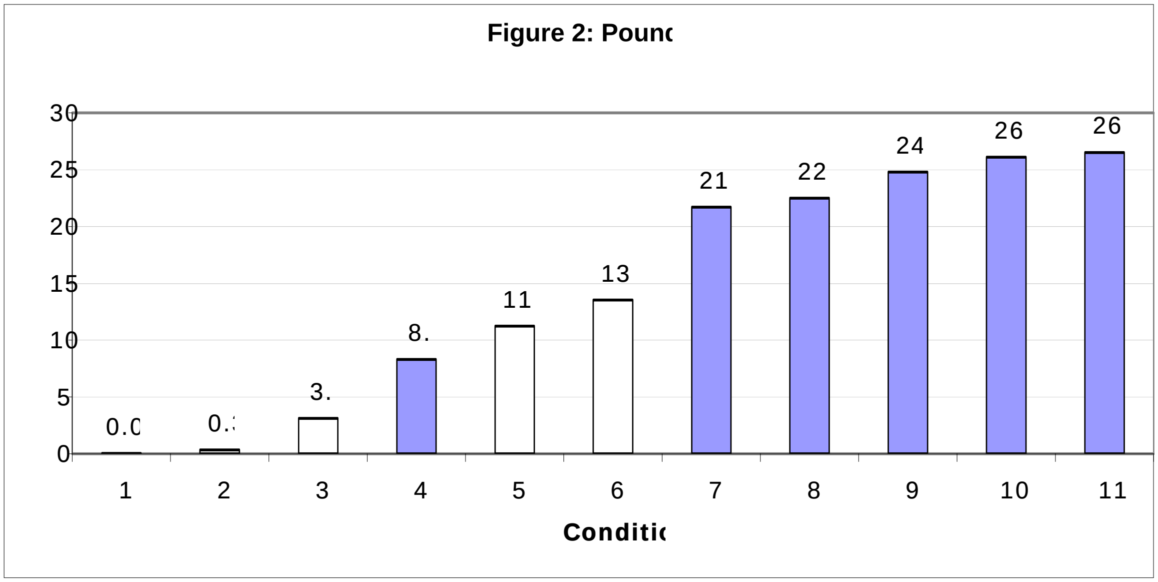
*psi = psig + 14.7

High-pressure NG stored underground at 2,700 psig and +110°F, will have a density of only 8.3 pounds per cubic feet, which is only 31.3% as dense as LNG. Even 3,600 psig L/CNG, a vehicle fuel dispensed from LNG into small high-pressure fuel tanks, is only 13.5 pounds per cubic feet, or 50.9% the density of LNG.

By contrast, -150°F CCNG, at only 700 psig, has a density of 21.7 pounds per cubic feet, or 81.9% the density of LNG. At a storage pressure of 1,500 psig, CCNG has a density of 22.5 pounds per cubic feet, or 84.9% of the density of LNG. CCNG is nearly three times as dense as NG stored warm in high-pressure underground storage facilities, and **62 times as dense** as the NG in stored in a 100-psig "line packed" pipeline. It is that major increase in density that yields economically viable techniques for producing, storing and transporting CCNG.

Figure 1 illustrates the relative densities as a percentage of the "coldest" available LNG, which at 26.5 pounds per cubic feet, is used here as the 100% standard. Figure 2 compares the density (pounds per cubic feet) of various storage options, and clearly shows (as conditions 7 and 8 in the table above and the figures below) that CCNG fills a "gap" between high-pressure warm gas storage and low-pressure LNG storage.





At -150°F and colder and at 700 psig and greater pressures, CCNG fills that gap between high-pressure warm gas and low-pressure LNG, offering a new and more cost-effective way to store, transport and dispense natural gas. CCNG is a “sweet spot” on the “periodic table” of NG states. At relatively modest pressures and at relatively “warm” cryogenic temperatures, CCNG offers many of the advantages of LNG but without LNG’s shortcomings. Those shortcomings include the following: LNG is too cold for storage in unlined underground caverns; requires approximately 44% more energy input to achieve its moderately higher density; and will always be a two-phased fluid, with a vapor cloud above its liquid state, complicating its storage and transport.

The density of natural gas at low temperatures is exponentially dependent on its temperature, but only arithmetically dependent on its pressure. The highest densities (and the smallest containment volumes) will be achieved by refrigeration, not by compression.

The increased density achieved by refrigeration is also useful in various pipeline transport and storage models at cryogenic temperatures that are warmer than -150°F shown in Table 1 and Figures 1 and 2 above. In other words, CCNG as a “state” of natural gas can fit into a broad range of cryogenic temperatures and medium- to high-pressures, yielding various densities between standard NG and LNG, thus making it useful for a broad range of storage and transport methods.

1D: ENERGY-TO-DENSITY RATIO OF CCNG

The higher density of CCNG (and its reduced volume on a unit-BTU basis) requires the input of energy, mostly in the form of refrigeration. All forms of natural gas stored in underground or aboveground containers (or transported in pipelines, ships, or tractor-trailers), require the input of energy to achieve the density levels for that mode of storage or transport. The question is this: “What is achieved by the energy input?”

Table 2 compares most of the gas conditions in Table 1 relative to the amount of energy required to raise the density of 1MMBTU of natural gas from a base condition of 100 psig and ambient temperature (with a density of 0.35 pounds per cubic feet) to higher densities.

The required energy input is expressed in kilowatt-hours (KWH), and the energy input comparison for each density level is shown on the bottom line as the ratio of KWH to the achieved density in pounds/cubic feet. The KWH tabulations assumed commercial scale, highly efficient, “density enhancement” facilities in the approximate operating range of 5MM SCFD of capacity.

Table 2: Energy Input to Density Ratio For Pipeline-Quality Natural Gas

	1	2	3	4	5	6	7	8	9	10	11
CONDITION	Atmos.	Low-P.	High-P.	High-P.	High-P.	High-P.	Low-P.	High-P.	Warm	Cold	Coldest
NAME		**BASE**			CNG	L/CNG	CCNG	CCNG	LNG	LNG	LNG
Press. (psig)	0	100	900	2,700	3,600	3,600	700	1,500	50	50	50
Temp. (Deg. F)	+70	+60	+60	+110	+100	+30	-150	-150	-225	-255	-260
Pounds/Cu. Ft.)	0.045	0.35	3.1	8.3	11.2	13.5	22.5	23	24	26.1	26.5
Density of LNG	0.17%	1.32%	11.7%	**31.3%**	42.3%	50.9%	81.9%	84.9%	93.6%	98.5%	100%
Energy Required (KWH)	N.A.	N.A.	**3.1**	**4.7**	N.A.	N.A.	**8.5**	**8.7**	**11.5**	**14.7**	**15**
KWH-to-Density Ratio	N.A.	N.A.	**1.0**	**0.566**	N.A.	N.A.	**0.392**	**0.387**	**0.464**	**0.563**	**0.566**

As expected, the required energy input increases as the density of the natural gas increases. However, the energy-to-density ratios tend to diminish as higher density levels are reached, but show a slight rise in those ratios (at the right side of the table) at “colder” LNG conditions. The general decrease in the energy-to-density ratios is due to the following:

> **The power required to compress natural gas is proportional to the pressure achieved, raised to a fractional exponent, not to a whole-number exponent.**

In other words it makes sense to compress natural gas to achieve density. Without compression, pipeline systems would not work, underground storage would not be feasible, and CNG fleets would not exist.

The energy-to-density ratios of the two CCNG conditions shown in the tables and figures above are the lowest ratios for all the conditions of natural gas suitable for storage. At commercial scales, less energy input is required (on a KWH/density basis) to increase the density of 1MM BTU of natural gas from a “base” condition to CCNG then for any other condition of natural gas, including warm compressed gas and very cold LNG. This is due to the following:

> **At temperature zones before natural gas becomes a liquid, the density of the NG increases in a “greater-than-one” exponential proportion to absolute temperature. As NG gets colder, significant increases in density can be achieved with small temperature reductions (cooling).**

Thus, if compressing natural gas to increase its density makes sense (and it does), then chilling it makes more sense. Instead of an energy input “penalty” for achieving the higher densities of CCNG, the actual energy input required is lower per achieved density then for all other warmer and colder methods of storing natural gas. CCNG offers a very dense form of NG, a form that requires the least energy input relative to the density achieved.

1E: OTHER CCNG BENEFITS

The following additional benefits of CCNG have been identified:

- A significant portion of the refrigeration energy in CCNG (as measured in billion BTUs) can be recovered and stored during outflow from a CCNG vessel to a standard pipeline, which can be used to chill incoming natural gas during the next inflow. By contrast, the compression energy expended in warm gas transport or storage (in caverns or in spent gas fields or at pipeline compressor stations) cannot be recovered in a practical way.

- Another form of "cold recovery" can use the refrigeration content of the CCNG to pre-cool the inlet air at a power plant, yielding higher efficiency power production and recovering a significant portion of the energy required to make the CCNG in the first place.

- In addition to "cold recovery" during outflow, a portion of the energy required to chill NG into CCNG can be stored in advance of inflow in a "working fluid", thus allowing for faster inflow and outflow cycles. By contrast, there is no practical way to store the compression required for CNG storage prior to its need.

- When cold recovery systems are integrated with CCNG storage models, that comprehensive approach further improves CCNG's preeminent position on Table 2 above.

- The production of CCNG, say at pipeline compressor stations, can take advantage of heat recovery opportunities, such as waste engine heat, which is usually thrown away, but which can contribute to the chilling of CCNG by way of absorption refrigeration.

- CCNG can be contained in aboveground cryogenic pressure vessels, allowing for transport by trucks to remote pipelines, to downstream portions of pipelines needing pressure building, and to off-pipeline locations. In that mode, CCNG systems are much more efficient than CNG tube trailers and, unlike LNG systems, can operate with zero boil-off.

- CCNG can be transported long distances in dedicated pipelines that can be significantly less costly to build and operate than standard pipelines with the same throughput capacity.

- The high-density of CCNG (a "near liquid") allows it to be pumped rather than compressed, much like standard liquids. That feature allows pumping stations along a CCNG pipeline in lieu of compressor stations, reducing the required energy input to keep the product moving.

Section 2
CCNG PRODUCTION BY THE VX CYCLE

Expansion Energy LLC has developed a patent pending design for the production of LNG and CCNG, including at small-scale (local) facilities.

U.S. Patent Application No. 11/934,845, for a **“Method and System for the Small-Scale Production of Liquid Natural Gas from Low-Pressure Pipeline Gas”.**

The cycle is known as “Vandor’s Expansion Cycle”, or the “VX Cycle”. The first goal of that invention was to facilitate the production of vehicle-grade LNG for bus and truck fleets, with each LNG plant serving a single fleet at its depot, thus avoiding the need to transport the LNG from its production source (usually a large LNG plant far from product’s destination) to various end-users. However, the VX Cycle also allows for peakshaving models at any scale, including the production of CCNG and production at off-pipeline sources of methane, e.g. stranded natural gas fields.

2A: WHAT ARE THE BENEFITS OF THE VX CYCLE?

The VX cycle offers several opportunities relative to the issues covered here. For example, it can serve as an on-site peakshaving plant for gas-fired power plants and for other large NG customers. The LNG produced can be pumped, transported and stored as CCNG. Alternatively, the VX Cycle can produce CCNG, but with lower energy costs because CCNG requires less refrigeration input.

With the exception of the VX Cycle there are no commercially viable small-scale LNG plants (less then 20,000 liters/day) anywhere in the world, and no CCNG production facilities. Existing LNG-fueled truck or bus fleets depend on tanker deliveries from large-scale plants or import terminals, increasing the cost of the product.

The customer must maintain a large storage tank at its fueling depot so that frequent deliveries can be avoided. Such tanks produce boil-off which, if vented to the atmosphere, is an unwanted methane emission and constitutes a significant loss of valuable product.

The relatively low capital cost of the VX Cycle and its high operating efficiency yields a cost effective way to produce LNG (or CCNG) at small-scale plants, with capacities above 2,000 GPD. By contrast, the smallest commercial LNG plant produces approximately 25,000 gallons (95,000 liters) per day. The VX Cycle is economically viable at “retail” production rates with each VX plant acting as an “appliance” and serving one customer. In the context of this report, that customer can be an individual power plant, a large user of natural gas, or a local pipeline network, say, downstream from a “bottleneck”. As an appliance, the VX Cycle can be integrated with existing pipeline compressor stations, allowing such facilities to become moderate-scale, distributed NG storage sites. As such, those sites could mitigate pipeline bottlenecks, and produce product for off-site use, including as a vehicle fuel and for pressure building at other nearby pipelines.

A “distributed generation” model for LNG/CCNG production has many benefits over the existing model that relies on one or two large LNG plants for production; a fleet of LNG trailers for distribution; and a series of LNG storage tanks and dispensers at each end-user. These benefits of distributed LNG/CCNG production include the following:

- Elimination of the cost of transporting product on roads. Those costs include “internal” costs associated with fueling the trucks and paying for labor, insurance, maintenance, and “external” costs related to traffic congestion, road use and wear, emissions from the trucks and the boil-off during transit.

- By definition, each distributed LNG/CCNG generation site has the capacity to re-liquefy boil-off, which is not the case for the standard LNG distribution model, where the end-user does not have re-liquefaction equipment.

- The scale of each facility, including the storage tank, will be much more modest, resembling standard fuel service depots, requiring smaller profile storage tanks, because the tank is merely a "buffer" in the production cycle, rather then a longer-term storage vessel.

- The permitting and financing of smaller facilities with predictable customers (at the site of each location) will be easier then the permitting and financing of a larger LNG plant that requires long term customer commitments in advance of construction.

The prototype 6,000-liter/day VX Cycle LNG plant is being constructed for less than ∉1,000,000 (approximately $1.5M). The Cycle yields approximately 85% LNG from every unit of natural gas that enters the plant, with only 15% of the gas used as fuel for the prime mover (engine or turbine). A 90/10 ratio of product to fuel is possible with certain optimizations, and even greater efficiencies will be achieved if the product is CCNG, rather then LNG, because CCNG requires less refrigeration. The combination of low capital cost and high operating efficiency yields an LNG/CCNG "price per gallon" that can be sold at a discount to diesel, on a BTU-equivalent basis.

2B: HOW IS THE VX CYCLE INNOVATIVE?

The VX Cycle assumes that a low-pressure (60 psia or greater) natural gas pipeline or stranded well is adjacent to the plant site; with a chemical composition that is 95% methane, with some N_2 and CO_2, but otherwise "clean" and dry. If the pipeline gas is not clean, there are several known clean up steps that can be integrated with the VX Cycle. Higher-pressure gas feed improves the efficiency of the VX Cycle.

The low-pressure gas stream is separated into a fuel stream (say, 15%) for the prime mover (engine or turbine), and a product stream (85%) to be compressed and liquefied. CO_2 and water are removed in a multi-vessel molecular sieve, which requires periodic regeneration. The regeneration gas is sent to the prime mover for use as fuel. The cleaned gas is then sent to a multi-stage CNG compressor, such as used at existing CNG stations. This is the **first innovation** in the VX Cycle:

1. **The use of a CNG station and/or standard CNG equipment to produce LNG.**

The VX Cycle allows existing CNG stations to be upgraded to LNG production. A network of small-scale LNG/CCNG plants can be integrated with existing (sometimes underutilized) CNG stations and possibly with existing pipeline compressor stations.

The feed gas is compressed, in stages, from 60-psia to approximately 400 psia. That choice is an essential feature of the invention because up to 3,500 psia is routinely provided by most CNG compressors. Operating a CNG compressor at lower pressures reduces its workload and the "heat of compression".

The CNG compressor is both the feed gas compressor and the recycle compressor. This is possible because the VX Cycle is an "all methane" cycle, where the working fluid (refrigerant) and the feed stream are both methane. This is a major advance in LNG/CCNG production, because the only LNG plants that now use methane cycles are letdown plants. Standard letdown plants (and the small LNG plant at Sacramento) do not require re-compression because they rely on high-pressure feed gas, and have the opportunity to send out large quantities of low-pressure gas into local low-pressure pipelines. The VX Cycle does not require those special conditions.

The VX Cycle uses a uniquely integrated absorption chiller to counteract the heat of compression and to pre-cool the CNG immediately after it exits the compressor's after-cooler. That unique use of a well-established technology (absorption chilling) is the **second innovation** as follows:

2. **Heat of compression is mitigated, and the natural gas is pre-cooled by an absorption chiller powered by waste heat from the prime mover.**

The **third innovation** is the unique integration of the prime mover, the compressor and the absorption chiller:

3. **The "front-end" -- engine, chiller, and CNG compressor -- is linked, each to the other two components, allowing standard CNG equipment to produce cold, moderate pressure CNG.**

The VX Cycle exploits the limitations of low-pressure methane compression-to-expansion, without using refrigerants such as N2 in nitrogen expansion cycles; or "mixed refrigerants" in MR cycles; or hydrocarbons in cascade cycles; and without the inefficiencies of high-pressure Joule Thompson (JT) cycles. The VX Cycle achieves a good degree of the efficiency of turbo-expander (letdown) LNG plants, but at much lower capital costs, and without a high-pressure inlet stream or a low-pressure outflow "sink".

The **fourth innovation** is found in the "back end" of the VX Cycle:

4. **Joule Thompson valves and a turbo-expander are integrated at the back-end to convert the cold CNG into LNG.**

In order to achieve -250°F LNG at 65 psia, (or –150°F CCNG at a higher pressure) significantly more refrigeration is needed then can be provided by the front-end chiller. Two sources of refrigeration are at work near main the heat exchanger. The first is a throttle valve. The pre-cooled CNG at +/- 400 psia is sent through the main heat exchanger where it is cooled to –170°F by the other streams within the exchanger. That combination of approximately 400 psia and –170°F allows for "plate fin" heat exchangers rather then the more-expensive coil wound units.

CCNG may be the end product of the VX Cycle. However, if a colder and denser product is desired, such as LNG, then a portion of the -170°F stream, at +/- 400 psia, is sent through the throttle valve, which yields approximately -254°F vapor and liquid at a pressure of only 19 psia. That cold vapor + liquid stream is used to sub-cool the portion of the stream that is still at -170°F and 400 psia, cooling it to -251°F and still at +/- 400 psia. The sub-cooled product is dropped in pressure to 65 psia; forming LNG at -250°F, which can be sent to the storage tank, without any "flash" (vapor) formation. Various options exist for the final storage temperature and pressure of the LNG (of CCNG) depending on the intended use for the product.

The low-pressure stream that cooled the main product stream in the sub-cooler is sent back toward the beginning of the process as part of the recycle stream. Prior to its return trip through the main heat exchanger, the recycle stream is mixed with the recycle stream from a compressor-loaded cryogenic methane turbo-expander – the second source of refrigeration. The turbo expander is needed because JT refrigeration is not efficient enough. The expander converts cold CNG to colder, lower-pressure natural gas by doing “work”. Expansion Energy has identified a US maker of highly efficient, affordable, gas-bearing, compressor-loaded, cryogenic expanders.

Both the throttle valve and the expander function well with the 400-psia inlet pressures. The 400 psia is a “comfortable” inlet pressure for a small expander. The selected refrigeration methods, and the conditions at which they operate, yield an excellent balance between refrigeration produced, the size and temperature of the recycle stream, the workload of the CNG compressor, and the total LNG/CCNG produced per unit of fuel used to run the plant.

Innovation #4 uniquely applies known JT and turbo-expander technology to a Small-Scale LNG/CCNG Plant in a specific, optimal manner:

> **The VX Cycle uses the main CNG stream as a “working fluid” (refrigerant) to liquefy a significant portion of the stream, returning a “recycle” portion for re-compression, but only after several “cold recovery” steps.**

2C: WHAT IS THE DEVELOPMENT STATUS OF THE VX CYCLE?

Expansion Energy LLC is actively pursuing licensing opportunities with qualified entities to build and deploy the VX Cycle LNG plant, at pipelines and at stranded gas fields.

As mentioned above, the VX Cycle is “patent pending” in the US. International patent applications will be submitted during the next 9 months. As part of a peer review process, the invention has been disclosed to two Italian entities, one of which is a maker of CNG compressors. Those entities are constructing a single, 6,000-liter/day “prototype” plant for testing and validation. Subsequent deployments would be based on a yet to be concluded licensing agreements between Expansion Energy LLC and the builder of the prototype and other parties.

The prototype plant will be completed by mid-2008. Chart Industries (in the UK) is building the main heat exchanger. The compressor-loaded turbo expander has been built, tested, and shipped to Italy by its US maker. All other equipment is on hand in Italy, most of which was purchased “off the shelf”. Validation of the prototype is scheduled for the second half of 2008, with commercial deployment by the end of 2009.

Section 3
DEPLOYMENT OF CCNG SYSTEMS

This section of the report will examine how CCNG systems (and distributed LNG production and storage systems) might be deployed in California, especially to address three specific scenarios provided to Expansion Energy LLC by GTI. The three scenarios are outlined in Section 3A. Analysis of the scenarios and CCNG/LNG solutions are discussed in subsequent sections. That analysis will include some assumptions regarding the “scale” of each scenario. For example, for the first scenario, a fine-tuned analysis would be based on a demand profile that accounted for different demand volumes during daytime and nighttime. Similarly, for the second scenario, it is likely that the power plant does not normally produce as much output (MW) at night as in the day, and that pipeline shortfalls may not exist at night. The same issue is relevant to Scenario 3.

In all cases, the following assumptions can be made:

- Local production of LNG/CCNG – a distributive model – will alleviate the peak period throughput demand on the NG grid;

- Small- and moderate-scale storage options in aboveground vessels and as line-packing will facilitate the delivery of the stored NG to the customer, bypassing bottlenecks, reducing transport costs and eliminating the conflict between pipeline capacity and the need to deliver peak volume product from distant, large-scale storage facilities;
- Distributed production and storage systems will operate with lower losses and will use less energy to deliver the stored product to the customer;
- Existing amortized equipment at power plants and compressor stations offer “platforms” on which distributive storage facilities can be deployed, reducing the capital investments required for such new facilities;
- Distributive solutions tend to be smaller, more in scale with other existing industrial systems near which they would be deployed, and thus more supportable by community groups than large-scale systems that “impact” only one or two communities.

3A: LOCAL STORAGE AND TRANSPORT SCENARIOS

Scenario 1: As a **peak shaving** and supplemental gas supply to large industrial customers to offset peak demand and provide a supplement or alternative to line-packing. An example would be key electrical generation stations, at the following scale:

- Approx. 2-3 MMSCF/hour deliverability, capable of sustaining 2-3 days of flow, at approximately 250 psia.

Scenario 2: As a **portable backup system** for emergencies and to mitigate planned and unplanned pipeline outages. These would be mobile, highly portable systems that might be strategically located in high-demand areas or in areas with known infrastructure limitations during peak demand periods, at the following scale:

- Approx. 6-8 MMSCF/hour deliverability, for 12-24 hours, at approximately 350 psia.

Scenario 3: For a **SoCalGas scenario,** similar to Scenario 1, at a location on the main feed line to the southern portion of the SoCalGas customer base, which is a bottleneck in their distribution and transmission system today. During peak demand periods supply is impacted by demand from upstream locations, reducing delivered volumes to the San Diego area. San Diego requires approximately 500 MMSCF/day to meet their peak demand. Delivery pressure into the pipeline is approximately 500 psia and the system needs to accommodate approximately 2-3 days of volume at 10 MMSCF/hour, with the other 50% of the demand met by a combination of firm storage and pipeline capacity.

3B: COMPREHENSIVE SOLUTION

A comprehensive solution to NG storage, pipeline throughput capacity, and the logistics of optimally connecting storage systems to end users by way of a limited and imperfect pipeline grid can have many components.

Conservation -- of the product stored and transported, and the available capacity of the system – can yield short-term improvements in deliverability. Beyond conservation, policy makers can examine other short- and long-term steps to improve the existing NG storage and distribution system. Those steps would include the following:

- Reduce line losses in all existing and future pipelines;
- Recover heat of compression and waste heat produced by natural gas fueled engines such as those that drive compressors;
- Utilize off-peak capacity at power plants and compressor stations to store kW / NG for peak period release;

- Eliminate boil-off from all existing and future LNG systems;
- Encourage distributive power production, using local LNG/CCNG production and storage systems.

Each of the three scenarios outlined in Section 3A, and other supply vs. demand issues, would be substantially reduced or eliminated if the California natural gas pipeline system (including compressor stations) had adequate capacity to meet demand along all segments of the system. Under those “ideal” circumstances, the only concern would be the total supply, from North American gas fields, from California storage fields, and from LNG import terminals. However, that ideal would require large funding expenditures and years of planning, permitting and construction.

One way to get closer to an ideal NG distribution system, with fewer hurdles, is to begin a program of CCNG pipeline construction. For example, relatively short-run CCNG “links” might eliminate or reduce the impacts of existing bottlenecks in the system. Other links might connect existing regional pipelines with excess capacity (say, from the Rocky Mountains) to not-too-distant portions of the gas grid that now operate with constrained capacity.

Such CCNG pipeline links might be deployed as new construction (within existing NG pipeline right of ways), or may be “retrofits” of existing “warm” carbon-steel pipelines. For example, Sempra’s LNG import terminal in Baja California might augment its send-out regime as follows. Instead of vaporizing all of the imported LNG, it would “pump” LNG to pressure, producing CCNG that would be as dense (or slightly denser) then LNG. The CCNG would then be transported north to San Diego in a dedicated CCNG pipeline, which would be appropriately insulated and which would have pumping stations along the way. Depending on the total length of the line, and the selected “arrival temperature” of the product in San Diego, there may not need to be any re-refrigeration stations along the route.

It should be noted that in the “continuum” from very cold LNG/CCNG, say, at -260°F and 1,200 psia, to standard CNG at 50°F and 100 psia, there are an infinite number of temperature and pressure values with their corresponding densities. An optimally designed CCNG pipeline would make “transitions” between various “states” of the NG in response to design goals related to pressure drop and the intended arrival temperature and pressure of the once-CCNG as CNG. For example, if warming were desired, prior to inserting CCNG to a standard CNG line, then the last segment of the CCNG line would not be insulated.

Such CCNG pipelines, while unprecedented, can be built with existing technologies, and will likely cost significantly less than the same length conventional pipeline with the same throughput. In addition to lower capital costs, the operating costs of a CCNG pipeline will be lower, because pumping requires substantially less energy than compression, and because the source LNG will not need to be vaporized. This model is certainly within the realm of possibilities for the California Energy Commission’s comprehensive 15-year planning process. (Shorter-term solutions are examined below.) Variations on this theme can be evaluated in the context of the LNG import terminal’s short- and long-term inflow rate vs. outflow demand. In other words, a CCNG send-out option may fit into Sempra’s plans and that of other import terminal operators, if not now, then at some point in the near future.

For northern California, a CCNG pipeline link might connect the proposed LNG import terminals in Oregon and/or offshore. A CCNG link to an offshore terminal would substantially eliminate the need for large LNG storage tanks, thus yielding fewer and smaller off-shore structures, which may result in less local opposition.

A less ambitious deployment of a CCNG pipeline would bypass an existing bottleneck. Instead of LNG as the feed source, one or more CCNG production facilities (using the VX Cycle) would be integrated with compressor stations on the upstream side of the bottleneck. The substantially increased outflow from that re-configured compressor stations would be sent past the bottleneck in a CCNG pipeline that would use existing rights of way, delivering extra product at any desired pressure to the network downstream from the bottleneck. The insulation regime for the CCNG line would allow the "arrival temperature" of the CCNG to be appropriate for insertion into existing CNG lines. A variation on that model may allow existing carbon steel links near the bottleneck to be upgraded to CCNG, by lining those segments.

Other CCNG pipeline links may include connections between newly built peaking plants (say, at electric power producers), which would send out CCNG at night (for line-packing) instead of selling low-value power during the night. In that model, the power plant would be an NG customer that would also produce CCNG to help alleviate shortfalls on the same grid that delivers the NG to the power plant. The CCNG pipeline would allow for its own line packing, after it delivered CNG to the existing grid for standard line packing.

In summary, the ideal long-term solution to the three scenarios outlined above is to comprehensively integrate LNG/CCNG production (or import) sources with CCNG pipelines. The production sources would include existing power plants that can redirect nighttime power output to LNG/CCNG production and existing compressor stations that would be upgraded to produce LNG/CCNG.

The following sections will examine options for mitigating the problems outlined in each of the three scenarios.

3C: SCENARIO 1

The most efficient long-term solution to Scenario 1 is the comprehensive plan outlined above. As discussed, the power plant would function at "full speed" 24/7, sending power out mostly in the daytime, and re-directing a portion its (lower-value) 10:00 PM to 6:00 AM power output toward the production of LNG/CCNG. In that manner, the power plant's output would always be the highest value product. Seen in that light, the nighttime, low-value power would be "stored" for daytime, high-value release, increasing the net value of the annual power output and also reducing the daytime demand on the NG grid.

If the CCNG pipeline connection were in place, as outlined above, the power plant's nighttime output would be mostly CCNG, which would require less energy input than LNG production. However, if the purpose of CCNG were for more than line packing, and if it also needs to be sent out during the daytime, then some of the power plant's nighttime production would include LNG. The stored LNG would be pumped and sent out by the CCNG line, but only after a degree of cold recovery. Some of the delta between -260°F LNG and, say, -150°F CCNG would be used to pre-cool the inlet air to the power plant's gas turbine, substantially improving its efficiency. The cold recovery from the sent-out CCNG would further reduce the "cost" of the product.

That comprehensive cold recovery and power enhancement design is the subject of another Expansion Energy LLC pending patent:

U.S. Patent Application No. 12/043,059, for **" A Combined Cold and Power (CCP) System and Method for Improved Turbine Performance".**

That patent is called the "VCCP Cycle", for "Vandor's Combined Cold and Power Cycle", as compared to combined heat and power (CHP) cycles. The VCCP Cycle yields the most dramatic fuel savings when integrated with simple cycle gas turbines. In large combined cycle power plants, the VCCP Cycle yields modest percentage gains (say, 2 points) in thermal efficiency. However, such a fuel efficiency improvement can be significant if it occurs during the peak NG demand period.

The optimal size of the VX Cycle LNG/CCNG plant will need to account for the limits (if any) on the size of the on-site LNG storage tanks. (CCNG cannot be stored cost-effectively in large aboveground storage vessels.) For example, if only two shop-fabricated (horizontal) 75,000 gallon LNG tanks could be placed at an existing 300 MW power plant, with a total capacity of 150,000 gallons, the size of the peaking LNG plant would be, in part, derived from that constraint.

To advance the example further, we estimate that 2,000,000 SCF/hour of natural gas would generate 300 MW in a combined cycle power plant. We might assume that such a 300 MW power plant routinely sends out 250 MW, but needs to send out the additional 50 MW on peak demand days (during the summer) for electricity. The peak period might last a full 8 hours. Thus, the "extra" 50 MW will need approximately 333,000 SCF of NG for 8 hours, a total of 2.67 MM cubic feet, or approximately 32,000 gallons of LNG. For the purposes of this example, we can assume that instead of sending out CCNG into the grid to offset the power plant's "extra" NG demand, it merely uses that 32,000 gallons on site, to produce the extra 50 MW, thus eliminating a 2.67 MM cubic feet "draw" on the NG pipeline during that 8-hour peak period.

If the site had a 60,000 GPD VX Cycle LNG plant, it would produce 20,000 gallons during the 8-hours of nighttime, when NG demand is lowest. (That 8-hour nighttime LNG production may be extended to as long as 16-hours, if gas availability and pricing permit, and if the storage tanks have capacity.) The 20,000 gallons (or more) produced during the off-peak period would allow the system to function for 12.5 consecutive days, because each day's use of 32,000 gallons would be partially made up by the 20,000 gallons produced at night. If the peak demand days were not consecutive or only briefly so, then the system would be self-sustaining indefinitely.

Clearly, a combination of a 60,000 GPD VX Cycle LNG plant and 150,000 gallons of storage would be adequate for storing enough LNG to allow a combined cycle power plant to produce 50 MW of "extra" power for 8 hours, without drawing on the NG grid for the required 2.67-million cubic feet of gas. The model outlined above can function through 12 days of peak power and peak NG demand. A smaller LNG plant and/or less storage capacity may be viable if the likelihood of 12 consecutive "peak" days is remote.

On the other hand, if the 12 consecutive days of peak demand is realistic and if the peak demand for NG is greater than in the model above, adjustments to the LNG production and storage capacity would be made. First, more storage would be planned for. However, that would only be viable if the consecutive peak periods were short in duration with several days between each period. If the consecutive peak periods were weeks long, each peak period closely followed by another, then, in addition to more storage, a larger VX Cycle LNG plant would be needed. An optimization would project historic patterns forward, with adjustments for anticipated increases in power demand, natural gas demand and rising global temperatures. The calculations would account for the increased fuel efficiency of the power plant as it took advantage of cold recovery by the VCCP Cycle.

As mentioned above, the stored LNG would likely be most useful at the power plant, for its own use. In that model the low-value nighttime power output would be stored as LNG, which would be used during the day as fuel, and which would "release" its refrigeration content (a portion of the stored energy input) as refrigeration for cooling the inlet air to the prime mover. That "power storage" model is substantially more effective (in terms of power output and duration) then flywheels or large array of batteries; it will not require large, sloping sites as do "pump power" schemes; and does not require underground caverns, as do compressed air storage systems; and will be more efficient then all such other power storage methods.

Operating in that mode, the power plant will enhance the value of its power output (by converting low-value nighttime power to high-value daytime output); it will increase its daytime efficiency by the use of cold inlet air to the prime mover; and it will reduce its daytime demand for pipeline supplied NG.

Conditions may occur where the NG grid needs product (say in the winter) and the power plant is not sending out any "extra" power. In that case, the power plant's LNG/CCNG equipment can mitigate such off-site NG shortfalls. In the absence of a CCNG pipeline link from the power plant to the underserved grid, the model may still be an effective solution. For example, daytime send out would be not as CCNG but as CNG, after recovering the cold from the LNG, as described above. However, the deployment of a CCNG link to some other point downstream of the power plant, within the service area impacted by the bottleneck, would allow faster and more specific delivery to, say, industrial areas, and would allow significantly more line packing at night in the CCNG segment.

3D: SCENARIO 2

Scenario 2 is especially "ripe" for a CCNG-based solution because the current method of delivering CNG in tanks (or tube trailers) is very inefficient. At CNG densities, such delivery systems move a great deal of steel (as the pressure vessel CNG container) but not much natural gas.

The most obvious alternative is to deliver product as LNG or as CCNG. Transport vehicles for LNG delivery are commonly available. A CCNG delivery truck is not yet commercially available. However, it would be very similar to an LNG trailer, but with the capacity to contain the higher-pressures of CCNG. The benefits of a CCNG delivery system would include lower production costs for the product, instantaneous pressure at the delivery site, and no boil-off. For the short term, Scenario 2 can be "solved" by VX Cycle-produced LNG delivery.

The scale of the comprehensive system needs careful optimization. For example, if a delivery rate of 6 MMSCF/hour were needed at a single receiving site, then 72,000 G/hour would need to arrive there. If each delivery truck contained 10,000 gallons of product (although there are 12,000 gallon trailers available), then 7.2 truck-deliveries per hour would be needed. If that demand rate persisted for more than one hour, the delivery fleet would need to be large (to allow for back and forth trips between the delivery site and the supply source); and the stored LNG would need to be close to all the possible locations where it might be needed (to reduce back and forth travel time); the storage capacity at the production sites would need to be significant; or the size of the LNG production plant would need to be large, in order to quickly make up any draw-down from storage. In other words, the logistical challenges of today's LNG production storage and transport models are daunting.

However, any comprehensive plan that includes a network of VX Cycle LNG plants (say, integrated with strategically located pipeline compressor stations) can meet that challenge and mitigate the conditions in Scenario 2. For example, each VX plant would have a capacity of 10,000 GPD, and would be supported by a single 75,0000 G (horizontal) storage tank and a moderately sized fleet of delivery trucks.

When Scenario 2 is not in effect, and when the storage tanks are full, each such Small-Scale LNG plant could produce product for the Alternative Fuel Vehicle (AFV) market (including for vehicles that serve CA's ports); or for off-pipeline demand, in markets now served by propane, diesel fuel or oil. Such off-pipeline markets would include the large areas of California that are not served by natural gas pipelines. With natural gas costs at approximately 50% of the cost of diesel or propane (on a BTU equivalent basis), the off-pipeline sale of LNG/CCNG can be a viable business and an effective tool for increasing the use of natural gas, which is cleaner than other alternatives.

The AFV market would also include farm equipment and other off-road vehicles, and generators, such as those that serve irrigation systems. In other words, the "emergency" supply purpose of such distributed generation LNG/CCNG plants would be augmented by a steady outflow of clean fuel for non-emergency uses. That multi-purpose approach yields faster amortization rates on the cost of the plant and will make them economically viable. In other words, the economic viability of the plants would not depend only on meeting the needs outlined in Scenario 2, but on a much steadier and more predictable daily customer base. The "distributed" location of a network of such VX plants would well serve the needs of Scenario 2 and allow the plants to serve a diverse customer base in a reasonable radius of each plant.

3E: SCENARIO 3

Scenario 3 is a variation of Scenario 1 with elements of Scenario 2. As discussed above, it is a prime model of how a CCNG pipeline can transfer imported LNG inland in a cost-effective manner, without first "throwing away" the inherent density of the LNG, and without "spending" energy on the vaporization process.

It should be noted that most LNG import terminals require an on-site system of heavy hydrocarbon removal to bring the LNG up to US pipeline quality. In selecting such a system, the goal should be to reduce emissions to zero; to achieve high efficiencies (by lower fuel use); to find the highest and best use for the removed heavies; and to end up with a cryogenic form of NG so that it can move on as CCNG, rather then vaporized CNG.

3F: THE VPX SYSTEM

The models discussed above have common themes. In all cases, the overall delivery and storage problem would be mitigated by optimally located LNG/CCNG production, storage and transport systems that, together, substantially increase the density of natural gas by refrigeration. The solutions outlined can achieve a more than **60-fold** density increase when compared to warm NG in a 100-psia pipeline. However, such large density increases require the deployment of specialized equipment at strategic locations within the NG network.

Expansion Energy LLC has developed a complementary approach to increasing pipeline throughput that relies less on a few, widely placed "high-density-producing" elements and allows significant increases in system capacity with relatively low-tech, broadly deployed components. This approach is unique, innovative and not obvious, thus suitable for yet another patent application, which is being prepared for submission to the US Patent Office. A detailed description cannot be offered here, because it would jeopardize Expansion Energy's patent rights.

The invention, tentatively called "Vandor's Pipeline Expansion System" ("VPX") is not a substitute for the systems and methods outlined above. Instead, VPX is a set of steps that achieve incremental expansion of pipeline capacity. Those steps would be taken in a "preliminary" effort to achieve the more dramatic capacity increases that CCNG systems can produce. For example, in one application of VPX, the throughput in a standard pipeline can increase 25% to 40% above existing maximum throughput.

While that is not as dramatic as the, say, 7-times throughput of a new CCNG pipeline (when compared to the same sized standard line operating at the same pressure), the 25% to 40% increase offered by VPX can be achieved now, with readily available equipment, and with relatively minor modifications to the existing natural gas infrastructure. If implemented, the 25% to 40% increase in capacity, generalized across as much of the California natural gas grid as deemed appropriate, would significantly mitigate delivery problems, allowing the utilities and policy makers time to evaluate, design, permit, and construct individual components of the CCNG-system outlined above.

A comprehensive plan for improving pipeline capacity and local storage options would start with VPX, (including the removal of water and CO_2 from the product stream) and, over time, would continue with the CCNG models outlined above.

Section 4
FEASIBILITY, SCALIBILITY

All of the methods and systems discussed here are feasible and can be economically deployed at a variety of scales. Some elements will require a period of testing and permitting before deployment. Other components are deployable today.

4A: TIME SCALES

CCNG pipeline would need to undergo detailed design, prototype testing and validation, drafting and adoption of amendments to applicable pipeline construction permits and protocols, and the processing of permit applications for the commercial deployment of such CCNG lines. That process can take several years, but would move faster if supported by State authorities, in recognition of the need to better match growing pipeline NG demand with the system's ability to deliver it.

Similarly, the design, prototype construction, testing and permitting of a "highway-certified" CCNG transport trailer can take several years. An expedited process would be justified if it can be demonstrated that the environmental benefits (eliminating boil-off) were substantial.

In contrast, the deployment of the VX and/or VCCP Cycles would take no longer than any other gas processing systems, because all aspects of those technologies fit within existing design and permitting protocols and use "off-the-shelf" components. As with all such projects the lead-time required for the delivery of critical components can be longer than one year. Heat exchangers, turbo-expanders, storage tanks, specialized valves, LNG tankers, and the like cannot be ordered from existing warehouse stock.

Almost any consequential new equipment installation or upgrading will likely need an environmental assessment and/or a degree of "community outreach" prior to deployment.

Some of the measures outlined here will take only a year or two of lead-time, while others will require many years of effort. With that in mind, the planning process for improving pipeline deliverability will benefit from an evaluation of what can be accomplished now (or soon), while the longer-term elements of the plan are advanced (starting as soon as possible) on their longer time scales. That evaluation will likely confirm that VPX is a necessary first step in the plan.

4B: SCALABILITY

Each of the elements described above can be deployed at a variety of scales, generally improving the economic viability of the system as the scale increases. By way of example, the list (in Section 5) of projected turnkey prices for VX Cycle LNG/CCNG plants shows that costs drop, per unit of output, as LNG/CCNG plants get larger, reflecting “economies of scale”.

Given the likely extent of the lead-time for the first deployment of a CCNG pipeline, planners will need to pick a scale that yields a significant increase in deliverability and line packing potential, so that the up-front investment is prudent. That suggests a larger diameter line operating at the higher-pressure ranges. However, if the length of the CCNG connection is relatively short, then the first deployment may avoid re-refrigeration stations and substantially limit (or avoid) the need for booster pumps along the route.

As described above, the most “dramatic” deployment of a CCNG pipeline would connect the Sempra LNG import terminal in Baja California with the San Diego grid to the north. As an international route, that option may be more complex then a shorter CCNG connection, entirely within California. On the other hand, a CCNG link from the import terminal northbound, but not crossing the US/Mexican border, may benefit from the different “view” of such projects in Mexico, as evident by the permitting of the LNG import terminal.

The smallest commercially viable VX Cycle LNG/CCNG plant will have a 1,500 GPD capacity. At that scale it will serve a single fleet as a source of vehicle fuel. At capacities of 10,000 GPD and larger it can likely be integrated with existing pipeline compressor stations per Scenario 2 above. At scales above that, VX Cycle plants can be deployed at large NG users as part of peakshaving systems, per Scenario 1 above.

CCNG transport trailers need to be designed for the maximum possible capacity. Under the coldest conditions, say, -260°F, CCNG at 700 psia will be slightly more dense then -260°F LNG at 50 psia. CCNG will not “slosh” in the trailer and will not need any “empty space” above the fluid to allow for boil-off. Thus, it is possible that CCNG trailers might carry more NG, within the total weight limit of the trailer then is now possible in LNG trailers. On the other hand, a pressure vessel will likely have thicker walls, increasing its weight, and limiting the product carrying capacity of the trailer. Further design work needs to be done to establish the optimum relationships between the structural configuration of a CCNG trailer, its dry weight, and its net carrying capacity. The goal would be to cost-effectively achieve capacity parity with LNG trailers, but avoid boil-off entirely.

The VCCP Cycle can significantly improve the efficiency of simple cycle micro- and mini-turbines. At such small scales the reduction in NG fuel demand would not be noticeable in the local NG distribution system. However at the scale of combined cycle power plants the few-point improvement in thermal efficiency, especially during peak NG demand periods, will yield a noticeable reduction in NG demand in the grid.

Section 5
ECONOMICS

This report outlined a wide range of technical and planning models, offering “hardware” as well as policy solutions for improving NG deliverability. At the macro scale the investment in new LNG/CCNG systems can yield several economic benefits in addition to solving the core problem of deliverability. Those economic gains would come from the broad integration of LNG/CCNG production, storage and distribution systems, beyond the existing pipeline network, expanding the role of natural gas in California. Some examples follow:

1. Several of the distributive LNG/CCNG models discussed could substantially help increase the penetration of LNG/CCNG/CNG in the AFV market and in off-road mobile and stationary equipment, displacing other, less clean fuels.
2. Distributive LNG/CCNG systems can also replace other fuels now used for non-vehicular service in portions of the state that are beyond the pipeline network.
3. Existing stranded gas fields (beyond the economic distance for a standard pipeline connection, or with non-pipeline quality gas) can become cost-effective in-state sources of NG.
4. The flaring of associated gas at existing and future oil wells can add another economically viable NG source, while reducing the emissions of flaring and utilizing a formerly wasted resource.
5. Under some circumstances, the production of LNG/CCNG may be a higher-value solution to energy recovery at landfills than the production of power, especially because LNG is a storable high-value product, while nighttime power output is a low-value product.
6. Similarly, a distributive LNG/CCNG network can use anaerobic digester gas (ADG) as a feedstock, yielding a high-value storable and transportable product.

All of the options above would benefit from a more aggressive deployment of LNG/CCNG production, storage and distribution systems. As those deployments increase, equipment costs will drop, design and permitting issues will become more routine, and public acceptance will increase, all of which will enhance the economic viability of each component of a growing LNG/CCNG network.

A detailed economic analysis of the various systems outlined above, and the specific solutions examined for the three scenarios in Section 3, could not be undertaken within the limited scope of this report. Such an analysis would be most useful if it were undertaken for a specific deployment at a real site with known conditions “on the ground”.

A detailed economic analysis would examine the costs of the existing system, and compare those to the long-term benefits of deploying the proposed technologies, accounting for capital (financing) and operating costs. The analysis should also account for externalities, such as, for example, the elimination of boil-off achieved in CCNG transport trailers, and improved efficiencies (and reduced emissions per kWH output) at power plants.

The following offers cost estimates for some of the specific components discussed above, including at different scales. The sections below place these estimates into the context of the scenarios outlined above.

- Shop fabricated LNG storage tanks: One 75,000 G tank at +/- $750,000 plus $150,000 for installation; two 75,000 G tanks, for a total capacity of 150,000 G, at +/-$1,500,000 plus $250,000 for installation
- LNG trailer: +/- $350,000
- CCNG trailer: +/- $450,000
- VX Cycle LNG/CCNG plant: 10,000 GPD at $3,000,000; 20,000 GPD at $4,750,000; 40,000 GPD at $7,500,000; 60,000 GPD at $9,750,000.
- CCNG pipeline at equal throughput of an equivalent standard pipeline: 20% to 50% lower cost, depending on total lengths.

5A: SCENARIO 1 COSTS

The turnkey cost of a single installation in response to Scenario 1 would be as follows:

- Approximately $9,750,000 for a 60,000 GPD VX Cycle LNG plant, plus $1,750,000 for installed storage, for a total cost of $11,500,000.

That cost would be offset by the following benefits:

- Substantial mitigation of the existing pipeline capacity shortfalls, and the avoidance of much of the costs of those shortfalls;
- The peak power output cycle will show a measurable increase in the power plant's efficiency, due to lower fuel use, because of the cold air inlet to the turbines, as a result of cold recovery from the vaporized LNG.
- The rated capacity of the power plant will be achieved during the hottest summer days (which are also the peak power demand days) because of the cold inlet air to the prime mover. Instead of underperforming on hot days, each power plant that is enhanced with cold recovery from an LNG peaking plant will be able to produce its full rated electric power output, mitigating the need for more power plant construction.

5B: SCENARIO 2 COSTS

If only three turnkey 10,000 GPD, distributed VX production plants are considered a "network" then the cost of that response to Scenario 2 would be as as follows:

- Three plants integrated with existing compressor stations, each at an approximate cost of $3,000,000 plus a 75,000 gallon storage container at each location, costing $900,000, installed, would total approximately $11,700,000 for the installed production and storage network.

That cost would be offset by the following benefits:

- Mitigation of the issues in Scenario 2;
- The advancement of a viable business model for distributed LNG/CCNG production, serving AFVs and off-pipeline customers, as outlined above;
- Substantial reduction in boil-off, yielding "internal" benefits to producers and customers through recovered product, and yielding "external" benefits related to reduced methane emissions.

5C: SCENARIO 3 COSTS

One solution to Scenario 3 is similar to scenario one. The more ambitious solution, which may be several years away, would "extend" Sempra's Baja California LNG import terminal north by way of a CCNG pipeline, allowing for a higher rate of delivery to San Diego. Preliminary estimates indicate that such a CCNG pipeline would be substantially less costly to build and operate then an equivalent capacity standard pipeline. However, a more detailed economic analysis would require an extensive study that would not only compare the material and construction costs of the two competing alternatives but would also take into account the following:

- The cost of increasing the receiving capacity at the import terminal, vs. the eliminated costs associated with not needing “vaporization” for CCNG send-out;
- The “sequence” issue: In the first instance, the terminal must construct or link up with existing standard pipelines, without waiting for the demonstration and permitting of a CCNG pipeline. At what point along San Diego’s growing natural gas demand curve would the extra investment in a CCNG line be prudent?

Section 6
SAFETY AND PERMITTING

The production, storage and transport of CNG and LNG are well-developed technologies with no particular public safety issues, other then those normally associated with any hydrocarbon system. Existing state and national standards adequately address the safety of the natural gas infrastructure, including the innovations outlined above. However, some aspects of the solutions discussed in this report will need to be reviewed to see if there are any gaps in those safety standards relative to the proposed technology.

The small-scale production of LNG, by the VX Cycle is well within existing safety protocols. The production of CCNG is also covered by standards for cryogenic pressure systems. The deployment of the first CCNG pipeline may require some extra effort with FERC and other reviewing entities. A successfully permitted and deployed short run “prototype” providing local, rather then national service, cold pave the way for more ambitious deployments that would follow.

Similarly, a CCNG delivery tanker would merely be an enhanced version of existing LNG, LOx and LN2 tankers, but with a pressure rating of above 700 psia. Certification of such a tanker by the appropriate CA and federal agencies may take some time.

Section 7
CONCLUSIONS

7A. GENERAL CONCLUSIONS

1. As the densest practical forms of natural gas, LNG and CCNG systems can significantly enhance existing storage and transport methods.
2. The production of LNG and/or CCNG is not without energy-input costs. However, the greatly enhanced density and the use of cold recovery techniques will more then offset those costs.
3. Of all forms of natural gas, CCNG requires the least energy input (kWH) relative to the density achieved.
4. Improved natural gas pipeline capacity and local storage will require a comprehensive plan that will begin with relatively low-cost and low-tech solutions (such as VPX) with more ambitious systems deployed as warranted by the need for such systems.
5. Distributive LNG/CCNG production, storage and transport will yield a better functioning and more responsive natural gas network, allowing for incremental investments in the new hardware.

6. The more widely deployed the improvements are, the lower the capital and operating costs will be and the more acceptable such systems will become. With wide deployment, the market share of natural gas will increase relative to other fuels.
7. Many of the technical systems that would improve pipeline and local storage capacities are available now and require no further basic research but need to be demonstrated in model projects.
8. All of the models outlined in this report will yield substantial environmental benefits.

7B. SPECIFIC CONCLUSIONS

1. Deeply chilled natural gas (CCNG) improves both pipeline throughput and line-packing regimes when applied to a CCCNG pipeline system, even if that system is a small part of the total NG grid.
2. Pipeline transport of CCNG is achievable because it can be pumped to pressure at periodic pumping stations, like a liquid, but will flow without forming "slug flow" as would be the case in the two-phase transport of LNG.
3. In many contexts, an optimal balance between compression and refrigeration is a better way to achieve high-density than compression alone.
4. The VX Cycle offers a broad range of scales for the cost-effective production of LNG/CCNG, and the Cycle can be integrated with existing CNG stations, pipeline compressor stations and with power plants.
5. At non-base-load scales, the VX Cycle will use the lowest amount of fuel per unit of LNG/CCNG produced, when compared to any other LNG/CCNG production cycle at an equal scale. The exception is "letdown" plants which can achieve near-zero fuel use, but which can only be deployed at a few, very special locations.
6. The VCCP Cycle will allow power plants to "store" nighttime power output for daytime release, reducing the NG demand on the pipeline grid during peak daytime periods.
7. Each of the technical solutions described in this report can be deployed at various scales, generally leading to lower costs per unit volume of production or storage.
8. The economic viability of each of the solutions discussed is demonstrable in light of the costs associated with pipeline and local storage capacity shortfalls.
9. The permitting protocols for some elements of a CCNG/LNG system will be fairly routine. Other elements (such as the first CCNG pipeline) may take a good deal of effort over several years, but may be expedited with the support of State and Federal agencies.

APPENDIX:
ABBREVIATIONS and TERMS

AFV	Alternative fuel vehicle
BTU	British thermal unit (a unit of heat energy)
CO2	Carbon dioxide
CNG	Compressed natural gas
CCNG	Cold compressed natural gas
GPD	U.S. gallons per day
KW	Kilowatt (1,000 watts)
KWH	Kilowatt hour
LNG	Liquid natural gas (mostly liquid methane)
MMBTU	1,000,000 BTU
MMSCF	1,000,000 standard cubic feet
N2	Nitrogen
NG	Natural gas (mostly methane)
psia	Pounds per square inch atmospheric (a unit of pressure)
psig	Pounds per square inch gauge