Journal of Natural Gas Science and Engineering 3 (2011) 326–333

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

journal homepage: www.elsevier.com/locate/jngse

Enhancement in NGL production and improvement in water dew point temperature by optimization of slug catchers' pressures in water dew point adjustment unit

M.R. Rahimpour [a,b,*], M. Seifi [a,c], K. Paymooni [a], A. Shariati [a], S. Raeissi [a]

[a] Department of Chemical Engineering, School of Chemical and Petroleum Engineering, Shiraz University, Shiraz 71345, Iran
[b] Gas Center of Excellence, Shiraz University, Shiraz 71345, Iran
[c] N.I.G.C., Sarkhun & Qeshm Gas Treating Co., Bandar Abbas, Iran

ARTICLE INFO

Article history:
Received 9 October 2010
Received in revised form
19 December 2010
Accepted 16 January 2011
Available online 11 March 2011

Keywords:
Process simulation
NGL production
Optimization
Diethylene glycol
Water dew point adjustment process

ABSTRACT

The water dew point adjustment is one of the most important processes in all gas refineries which reduces the water content of gas to some allowable limit and separates the heavy hydrocarbons from gas. In Sarkhun gas refinery, natural gas dehydration and hydrocarbon dew point adjustment are performed by cooling method. Diethylene glycol (DEG) is injected to gas–gas heat exchanger and chiller to absorb water from wet gas and act as a freezing inhibitor. Hydrate formation in filter elements was observed in this gas refinery which has been investigated in this research. The pressure difference between slug catchers and well streams were optimized by steady state process simulation software in order to decrease the mole percentage of C_{6+} exited along with the outlet gas stream from slug catcher and maximize the separation of liquid hydrocarbons. The pressure difference between the slug catcher unit and well streamlines was adjusted at optimized conditions and the experimental sampling was performed during modifications. The experimental results showed a considerable decrease in the mole percentage of C_{6+} exited along with the outlet gas stream from slug catcher and the simulation results showed 16500 bbl/year increase in NGL production rate. Operating under optimized pressure in the dew point adjustment unit of Sarkhun gas refinery decreased the water dew point temperature to $-26\ ^{\circ}C$ and improved the hydrocarbon dew point temperature to $-9\ ^{\circ}C$. Moreover, NGL and LPG production rates increased annually about 18672 ton and 6365 ton after modifications which results in \$11million extra annual income for company.

1. Introduction

The formation of hydrates in natural gas systems has been a problem to the gas processing industry for nearly a century (Hammerschmidt, 1934). Gas hydrates are ice-like crystalline compounds which get their stability through occupation of suitable size gas components (guest molecules) into cavities formed by water molecules (host molecules). In the gas industry, the blockage of transmission pipelines due to hydrate formation is often mentioned. This can be dangerous and could cause disasters. Usually, additives like methanol and ethylene glycol are injected into the pipelines to inhibit the formation of gas hydrates (Yousif and Young, 1994).

The wellhead stream from gas wells has some impurities such as water vapor, heavy hydrocarbons (i.e., gas condensate), hydrogen sulfide, N_2, CO_2, etc. In any gas refinery, several units such as the slug catcher unit, gas sweetening unit, dew point adjustment unit, glycol regeneration unit, etc., have been designed and established in accordance with the type of the inlet feed and the inlet molar flow rate (Riesenfield and Kohl, 1979; Katz et al., 1959). One of the most important units in gas refinery is the dew point adjustment unit which reduces the water content of gas to some allowable limit and separates the heavy hydrocarbons from gas (Rojey and Jaffret, 1997; Faulkner, 2006). The change in condition of the inlet feed, design conditions, degrading the chemical substances such as glycols, the application of improper filter elements, limitations in operational conditions and etc. lead to a sever disturbance in the performance of each refinery (www.nigc.ir).

The newly installed natural gas production plants are occasionally provided with NGL (ethane, propane, butanes and condensate) or LPG extraction capabilities to add more product value in addition to the producing of sales gas. The configurations of LNG plants and NGL/LPG extraction plants, especially the gas treating system and the dehydration system, are very similar to

* Corresponding author. Department of Chemical Engineering, School of Chemical and Petroleum Engineering, Shiraz University, Shiraz 71345, Iran. Tel.: +98 711 2303071; fax: +98 711 6287294.
E-mail address: rahimpor@shirazu.ac.ir (M.R. Rahimpour).

1875-5100/\$ – see front matter
doi:10.1016/j.jngse.2011.01.001

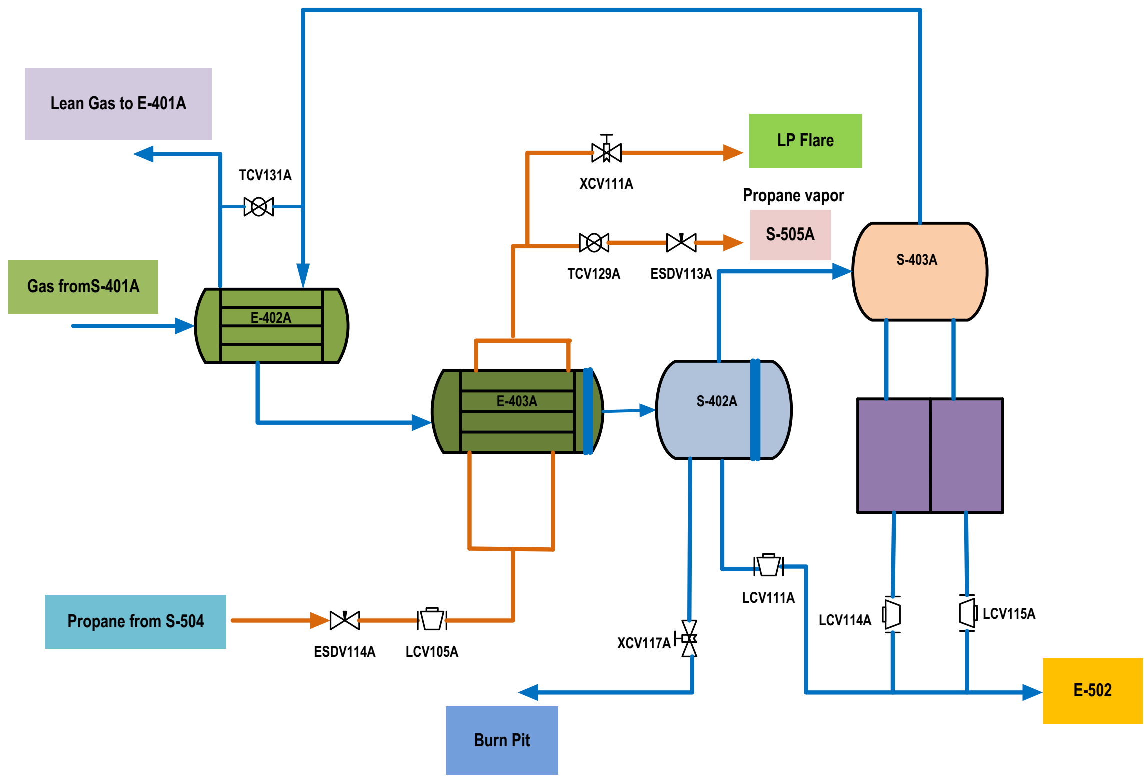

Fig. 1. A schematic diagram of the water dew point adjustment unit.

each other and many LNG plant projects integrating NGL/LPG extraction facilities or installing NGL/LPG extraction trains in parallel (Omori, 2007). Natural gas liquid (NGL) separation is an important link in any LNG plant. Recently, expander-based process has received increased attention, thanks to better appreciation of the refrigeration integration between NGL and LNG sections (Makitan et al., 2010). Traditionally the removal of NGL from the feed gas has been integrated into the pre cooling section, which provides partial condensation for separation. However, front end NGL recovery has recently used a conventional expander plant design with full pressure recovery. Integrated NGL recovery can employ different schemes, such as condensation by refrigerant or expander technology (Attaway et al., 2005). There are potential enhancements to the overall facility availability and project economics using the integrated concept. In these cases, LNG production has increased by approximately 7% (Elliot et al., 2005). Jibril et al. studied the production of NGL from natural gas. Natural gases of wide range compositions were tested for different turbo-expander process configurations (Jibril et al., 2005). Marzuka et al. designed mini-plants for extracting liquids from natural gas, assessing the existing technologies and using operational advantages that appear when a liquid extraction plant is coupled with a gas compression plant for crude oil secondary recovery (Trujillo et al., 2002). TECHNIP and TOTAL explored the application of an existing NGL recovery process to several industrial cases: extended extraction of C_3, associated with low, moderate and extended extraction of C_2 (Hagyard et al., 2004). Pierce et al. investigated a new design for integrated LNG production plant and the advantages of the new integrated designs for co-production of LNG in NGL recovery plants over current technology (Cuellar et al., 2002). Enterprise Products Operating LP and partner Marathon Oil Co. selected IPSI LLC's enhanced NGL recovery process after comparing available NGL recovery technologies for the new train. IPSI's technology replaced conventional propane refrigeration with a self-refrigeration and stripping gas package that allows up to 20% more processing capacity with the same residue-gas compression horsepower as in the existing train (Nasir et al., 2003). Foglietta introduced an alternative recycle reflux scheme to achieve higher NGL recoveries (Foglietta, 2000). Johnson et al. investigated the recent technical advances in the equipment for high NGL recovery (Finn et al., 1999). Baldonedo optimized the operating and the design of the refrigeration system and maximized NGL recovery.

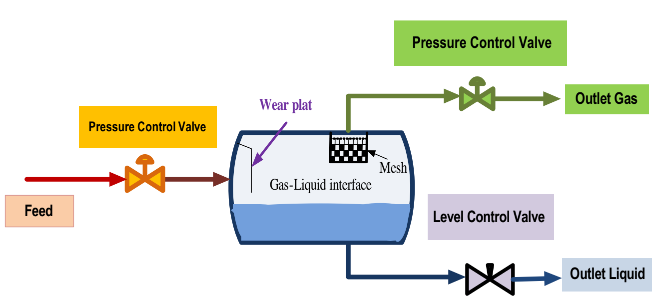

Fig. 2. A schematic diagram of a slug catcher.

Table 1
The optimized pressure difference between well streams and slug catcher.

Well no.	Separator no.	ΔP
1&15	S-101 O	5
2&4	S-101 C	5
3&16	S-101 A	5
5	S-202 G	25–37
6	S-202 D	25–30
7	S-202 C	25–30
9	S-101 B	5
10	S-202 H	25–30
11	S-202 E	25–30
12	S-202 A	25–30
13	S-202 B	25–30
14	S-202 F	7