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ИНОСТРАННЫЙ ЯЗЫК

МЕТОДИЧЕСКИЕ УКАЗАНИЯ

к проведению практических занятий и самостоятельной работы
для студентов направления подготовки
21.03.01 Нефтегазовое дело всех форм обучения

Воронеж 2022

УДК 811.111
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Иностранный язык: методические указания к проведению практических занятий и самостоятельной работы для студентов направления подготовки 21.03.01 «Нефтегазовое дело» всех форм обучения / ФГБОУ ВО «Воронежский государственный технический университет»; сост.: О. Г. Артемова. – Воронеж: Изд-во ВГТУ, 2022. 32 с.

Основной целью методических указаний является развитие навыков чтения, понимания и аннотирования текстов по специальности, а также развитие навыков говорения по отдельным темам в рамках дисциплины «Иностранный язык» в соответствии с тематикой рабочей программы дисциплины.

Предназначены для студентов направления подготовки 21.03.01 «Нефтегазовое дело» всех форм обучения.

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Введение

Целью проведения занятий по дисциплине «Иностранный язык» является приобретение коммуникативной компетенции, позволяющей будущим специалистам ориентироваться в современном информационном поле и владеть элементарными навыками межкультурной профессиональной коммуникации; повышение уровня культуры, общего образования и кругозора будущего специалиста.

Выполнение самостоятельной работы направлено на решение следующих задач:

- развитие навыка публичной речи (сообщение, доклад, дискуссия);
- развитие навыка чтения специальной литературы с целью получения профессиональной информации;
- формирование умения реферирования и аннотирования научных текстов по специальности;
- развитие основных навыков письма для подготовки публикаций и ведения переписки по специальности;
- развитие навыка использования иностранного (английского) языка для профессионального общения, достижения профессиональных целей и решения профессиональных задач (научно-исследовательских, аналитических, организационно-управленческих);
- развитие умения самостоятельно совершенствовать знания по иностранному языку.

В методических указаниях приведены задания для практических занятий, а также тексты для самостоятельной работы обучающихся. Задания выполняются с использованием возможностей глобальной сети Интернет для поиска необходимой информации на специализированных сайтах, работы с отраслевыми словарями.

RUSSIA's OIL PRODUCTION OUTLOOK

Грамматика: Времена групп Indefinite (Simple), Continuous (Progressive), Perfect Active

Задание 1. Прочитайте новые слова и запомните их значения. Переведите предложения с этими словами на русский язык.

1. rougbly – ориентировочно, приблизительно
2. United States Geological Survey (USGS)
   Геологическая служба США
3. to estimate – полагать, оценивать
4. feasible – осуществимый, возможный
5. conventional – удовлетворяющий техническим

In addition to roughly 67 barrels of probable and possible oil reserves, a 1998 USGS survey estimated that undiscovered, technically feasible, conventional reserves were larger than those of any other country in the world.

6. precipitously – стремительно
7. Soviet-era peak – максимум периода советской эпохи

Following the collapse of the Soviet Union in 1991, Russia’s oil production fell precipitously, reaching a 10w of rough1y 6 million bbl/d, or around one-half of the Soviet-era peak.

8. to cause – вызывать
9. decline – падение
10. depletion – истощение, уменьшение
11. due to – вследствие, в результате
12. state-mandated – подмандатный государству
13. surge – всплеск, рост

Several other factors аге thought to have caused the decline, including the depletion of the country’s largest fields due to state-mandated production surges and the collapse of the Soviet central planning system.

14. to attribute – относить
15. rebound – восстановление, быстрое повышение

Many analysts have attributed the rebound in production to the privatization of the industry following the collapse of the Soviet Union.

16. to clarify – выявить
17. incentive – стимул
18. expensive – дорогой
19. crude oil – сырая нефть

These production levels have made Russia the world’s second largest producer of crude oil, behind only Saudi Arabia.

22. taxation – налогообложение
23. revenue – доход
24. lack of smth – недостаток
25. subsoil – подпочва
26. to contribute – способствовать
27. forecast – прогноз

Government taxation of production and export revenues along with the continued lack of clarity concerning the ownership of subsoil resources has also contributed to lower forecasts for 2006.

28. investment – зд. инвестиционный
29. cornmunity – сообщество

30. oil supply growth – увеличение поставок нефти

In the last year, major energy agencies as well as the investment community have become increasingly pessimistic about oil supply growth in Russia.

31. to hinder – препятствовать
32. upstream – восходящий
33. returns – зд. отдача
34. to apply – применять

Increasing export and production taxes continues to hinder upstream development and decreases returns from applying new technology onto oil fields.

35. mature oil fields – зрелые нефтяные месторождения
36. slowdown – торможение

Production from mature oil fields has a major role in the recent slowdown in Russian oil supply growth.

37. ‘pre-peak’ fields – месторождения «допикового периода»
38. online – интерактивно
39. to add – добавлять

‘Pre-peak’ fields, which have come online in the last decade, can add between 0.9- 1.5 million bbl/d (barrels per day) to Russian supply according to a recent analysis of Russia’s oil supply.

40. to stem – задерживать

In the next 5 years, new fie1d developments will help stem production losses at older fields.

41. upstream – восходящий
42. sustained – длительный, непрерывный
43. certain – определенный

In the past, private fields have led much of the upstream development in Russia; but as the state nationalizes these firms, sustained improvements to exploration and development become less certain.

Задание 2. Прочтите данные интернациональные слова и назовите их русские эквиваленты.

Gas, journal, reserve, barrel, central, technical, region, peak, mil1ion, col1ape, era, factor, planning, system, privatization, industry, technology, standard, practice, effect, financial, crisis, ruble, seismic, potentia1, areas, resource, base, energy, economic, agency, pessimistic, export, decade, role, analysis, firm, nationalize, problematic.

Задание 3. Подберите русские эквиваленты к следующим словосочетаниям.

a) 1. according to	а) 1. вследствие
2. due to	2. вдобавок
3. allowing for	3. согласно
4. along with	4. учитывать
5. in addition to	5. вместе
b) 1. conventional reserves	б) 1. доходы от экспорта
2. oi1 production growth	2. зрелое нефтяное месторождение
3. export revenues	3. резервы, удовлетворяющие техническим условиям
4. high price environment	4. рост добычи нефти
5. mature oil field	5. окружение высоких цен

Задание 4. Сгруппируйте синонимы.

a) 1. to locate	**a)** 1. to provoke
2. to estimate	2. to promote
3. to cause	3. to account
4. to contribute	4. to guide
5. to manage	5. to place
b) 1. reserve	**b)** 1. decrease
2. survey	2. dominant
3. roughly	3. recovery
4. feasible	4. review
5. major	5. sharply
6. decline	6. supply
7. precipitously	7. approximately
8. rebound	8. attainable

Задание 5. Прочтите и переведите предложения, обращая внимание на форму сказуемого.

1. After years of neglect the environment has become a significant *issue* in Russia today. 2. Soviet po1icies that encouraged rapid industria1ization and development left a 1egacy of air pol1ution and nuc1ear waste with which Russia now is strugg1ing to contend. 3. The country’s energy and carbon intensities remain high and have on1y decreased marginally since the Soviet Union collapsed. 4. Despite the objections of nascent environmental groups, the post-Soviet Russian government has passed legislation to facilitate the permanent storage of other countries' nuclear wastes оп Russian territory. 5. Although environmental awareness· in Russia is rising, the cost of remediating the country’s environmental hot spots is high, and the Ministry of Natural Resources has a limited budget. 6. In November 2004, Russia ratified the Kyoto protocol on climate change. 7. The Protocol now enters into force since it has met the

threshold of being ratified by at least 55 countries that account for at least 55 percent of 1990's developed country greenhouse gas (GHG) emissions. 7. Since the fall of the Soviet Union, Russia's GHG emissions have fallen by about a third. 8. Russia will not have difficulty meeting its Kyoto target and can earn billions of dollars by selling back the difference between its emission targets (set in 1990) and its actual emissions.

Задание 6. Подберите правильную форму сказуемого и переведите предложения на русский язык.

1. In 2004, Russia's real gross domestic product ... by approximately 7.1 percent.

a) was grown b) grew c) has grown

2. The Russian Government … decoupling economic growth from commodity exports a priority.

a) make b) is being made c) has made

3. Kremlin policy makers ... to exhibit an inclination to advance the state's influence in the energy sector.

a) continue b) continues c) shall continue

4. Private oil companies complain that the higher export taxes . . . efficient allocation of profits into exploration and development.

a) is hindering b) are hindering c) will be hindered

5. Russia is important to world energy markets because it … the world's largest natural gas reserves, the second largest coal reserves and the eighth largest oil reserves.

a) hold b) held c) holds

6. Typically, a $1 per barrel change in oil prices ... in a $1.4 billion change in Russian revenues in the same direction.

a) result b) shall result c) will result

Задание 7. Употребите глагол, данный в скобках, в указанном времени.

1. As Russia's stabilization fund (to grow), using it to solve social problems or to buy other assets outside of Russia may become more likely (Present Simple).

2. Although estimates (to vary) widely, the World Bank (to suggest) that Russia's oil and gas sector may (to account) for up to 25 % of gross domestic product in 2003 while employing less than 1 % of the population (Present Simple, Present Perfect).

3. But, nationalizing parts of the energy sector (to come) at the expense of Russian oil and natural gas producers, who (to seek) to grow in a more liberalized marketplace, as well as Russia's external trading partners, who (to pressure) the country to synchronize its policies with those in Western Europe and North America (Present Perfect, Present Progressive).

4. Key to these efforts (to be) breaking up the monopolies that control the natural gas and electricity industries (Future Simple).

5. Even before oil prices (to reach) near-record levels, the stabilization fund was expected to be worth almost $52 billion by the end of 2005, or about 7 percent of the country's GDP (Past Simple).

6. Raw materials, such as oil, natural gas, and metals (to dominate) exports and (to account) for over two-thirds of all Russian export revenues (Present Simple).

7. Following the collapse of the Former Soviet Union, Russia's oil output (to fall) sharply and (to rebound) only in the last couple years (Past Simple, Present Perfect).

Работа с текстом А

Задание 8. Прочптайте текст А и постарайтесь понять его основное содержание.

TEXT A
RUSSIA's OIL PRODUCTION SURVEY

According to the Oil and Gas Journal, Russia has proven oil reserves of 60 billion barrels, most of which are located in Western Siberia, between the Ural Mountains and the Central Siberian Plateau. In addition to roughly 67 barrels of probable and possible oil reserves, a 1998 USGS survey estimated that undiscovered, technically feasible, conventional reserves were larger than those of any other country in the world.

In the 1980s, the Western Siberia region, also known as the 'Russian Core', made the Soviet Union a major world oil producer, allowing for peak production of 12.5 million barrels per day in 1988. Following the collapse of the Soviet Union in 1991, Russia's oil production fell precipitously, reaching a low of roughly 6 million bbl/d, or around one-half of the Soviet-era peak.

Several other factors are thought to have caused the decline, including the depletion of the country's largest fields due to state-mandated production surges and the collapse of the Soviet central planning system.

A turnaround in Russian oil output began in 1999. Many analysts have attributed the rebound in production to the privatization of the industry following the collapse of the Soviet Union. The privatization clarified incentives and increased less expensive production. Higher world oil prices (oil prices tripled between January

1999 and September 2000), the usage of technology that was standard practice in the West, and the rejuvenation of old oil fields also helped raise production levels. Others partially attribute the increase to after-effects of the 1998 financial crisis, the subsequent devaluation of the ruble, and the fall in oil prices.

By 2005 Russian total liquids production averaged almost 9.5 mi1lion bbl/d (9 million bbl/d of which was crude oil) – a 2.5 percent increase over 2004. This growth rate was down from annual growth of roughly 10 percent in 2004 and 2003. These production levels have made Russia the world’s second largest producer of crude oil, behind only Saudi Arabia.

The short-term outlook for Russian oil production growth is particularly unclear due to a lack of good seismic data and a lack of exploration in major potential producing areas during the last decade. Government taxation of production and export revenues along with the continued lack of clarity concerning the ownership of subsoil resources has also contributed to lower forecasts for 2006. Russia’s large oil resource base (President Vladimir Putin says it is much larger than the oft-cited 60 billion barrels) should enable the industry to increase production during a high price environment. However, even the Russian Ministry of Industry and Energy and Ministry of Economic Development and Trade have both reduced their outlook for oil supply growth from 4-5 percent per year in 2006 to 2-3 percent. In the last year, major energy agencies as well as the investment community have become increasingly pessimistic about oil supply growth in Russia. Increasing export and production taxes continues to hinder upstream development and decreases returns from applying new technology onto old fields.

In the upcoming decade, a few major oil fields will contribute to most of Russia’s supply growth and others will contribute to decreasing production from mature fields. Production from mature oil fields has a major role in the recent slowdown in Russian oil supply growth. ‘Pre-peak’ fields, which have come online in the last decade, can add between 0.9-1.5 million bbl/d to Russian supply according to a recent analysis of Russia’s oil supply.

New field developments will produce almost all of Russia’s annual oil growth in the next five years and will likely produce more than half of the country’s oil in 2020. In the next 5 years, new field developments at Lukoil’s Middle Caspian project (at Kurmangazy in 2006), the Sakhalin Island projects, the Shell Joint Venture’s West Salymskoye project, LukoillConocoPhillips’s TimanPechora project, RosneftlGazprom’s Prirazlomnoye project, and Rosneft’s Vankorskoye and Komsomolskoye will help stem production losses at older fields.

In the past, private firms have led much of the upstream development in Russia; but as the state nationalizes these firms, sustained improvements to exploration and development become less certain. Achieving continued growth at post-peak fields will become more problematic as oil companies run out of easy and less costly opportunities to manage the rate of decline.

Задание 9. Прочитайте текст А еще раз и найдите эквиваленты следующих словосочетаний.

Запасы нефти, доступный технически, крупнейший поставщик нефти, пик добычи, истощение крупнейших в стране месторождений, добыча нефти, восстановление старых месторождений нефти, падение цен на нефть, темп роста, сырая нефть, рост добычи нефти, налог на добычу, подпочвенные ресурсы, рост запасов нефти, налоги на добычу и экспорт, зрелые нефтяные месторождения, разработка новых месторождений, непрерывное улучшение разведки и разработки.

Задание 10. Ответьте на следующие вопросы по тексту:

1. How much oil do Russian oil reserves account for according to the Oil and Gas Journal?
2. What factors have caused the decline in oil production in 1990s?
3. What helped raise production levels in late 1990s?
4. What made Russia the world's second largest producer of crude oil?
5. Why has the outlook for oil supply growth been reduced?
6. What has a major role in the recent slowdown in Russian oil supply growth?
7. What will produce almost all of Russia's annual oil growth in the next five years?
8. Why will achieving continued growth at post-peak fields become problematic?

Задание 11. Составьте аннотацию текста, используя в качестве плана ответы на вопросы задания 10.

Работа с текстом В

Задание 12. Внимательно прочтите текст В и озаглавьте его.

TEXT B

Over 70 percent of Russian crude oil production is sent directly abroad for export, while the remaining 30 percent is refined locally. According to the latest data for November 2005, roughly l.4 million bbl/d of Russia's oil exports are sent via the multiple-branch Druzhba pipeline to Belarus, Ukraine, Germany, Poland, and other destinations in Central and Eastern Europe (including Hungary, Slovakia, and the Czech Republic). The remaining crude oil exports are sent to maritime ports in the Black Sea and Baltic Sea and are sold on world markets. Also, because of higher world oil prices recently, almost 170,000 bbl/d of Russia's oil is transported via railroad. Most of Russia's product exports consist of fuel oil and diesel fuel, which are used for heating in European countries and, on a very small scale, in the United States.

Expanding Russia's capacity to export oil in order to keep pace with the country's growing production is important to both Russian policy-makers and oil companies. However, the two sides are sometimes at odds over how best to boost the country's export capacity. Crude oil exports via pipeline fall under the exclusive jurisdiction of Russia's state-owned pipeline monopoly, Transneft. But bottlenecks in the Transneft system make the company's export capacity incapable of meeting oil producers export ambitions. Although Russia produces almost 7 million bbl/d of liquids (in net) for export, only about 4 million bbl/d can be transported by major trunk pipelines; the rest must be shipped by rail and river routes. Most of the 4 million bbl/d transported via alternative routes are petroleum by-products. Some of the crude oil export capacity deficit is also overcome by exporting these petroleum products. However, all of these alternate methods of exporting oil are much more costly than shipment via pipeline and could become less economical if world oil prices fall.

The Russian government and Transneft have acknowledged the capacity problem and have taken steps towards developing new export infrastructure. At issue, however, is not only the direction and scope of enhancements to the country's export infrastructure, but also the potential role that private firms and investors may play in these projects, presumably at the expense of state-owned Transneft.

During the first half of 2005, Russia exported almost million bbl/d of crude oil, well below predictions of 5.5 million bbl/d in late 2004. Russia also exported roughly 116,000 bbl/d to China during 2004, expects to export 160,000 bbl/d during 2005, and projects exports of 300,000 bbl/d in 2006. Under the Ministry's economic forecast, Russian oil exports could grow to around 5.8 million bbl/d in 2007, and up to 6.2 million bbl/d by 2015.

Задание 13. Ответьте на вопросы.

1. What way are Russia's crude oil exports sent to other countries?
2. What do most of Russia's product exports consist of?
3. What problems do Russian policy-makers and oil companies face?
4. What have the Russian government and Transneft done to overcome the exports problems?
5. How much crude oil did Russia export in 2004 and during the first half of 2005?
6. What is the Ministry's economic forecast towards Russian oil exports in 2007 and by 2015?

Задание 14. Выразите несколькими предложениями основную мысль текста B.

Работа с текстом C

Задание 15. Прочтите текст и ответьте на вопросы:

1. What is the advantage of BPS?
2. Why won't the pipeline to Indiga be built?

TEXT C

Proposed Oil Pipeline Routes and Pipeline Expansion Projects (Part 1)

Baltic Pipeline System (BPS)

The BPS came online in December 2001 carrying crude oil from Russia's West Siberian and Timan-Pechora oil provinces westward to the newly completed port of Primorsk in the Russian Gulf of Finland.

Throughput capacity at Primorsk has been steadily increased, reaching around 1.2 million bbl/d by September 2005. The BPS gives Russia a direct outlet to northern European markets, allowing the country to reduce its dependence on 'transit routes through Estonia, Latvia, and Lithuania. Unfortunately for the Baltic countries, the growth of the BPS has come at considerable cost, as Russian crude which traditionally moved through the Baltic region has been re-routed through the BPS. For example, crude oil shipments have dropped off almost 30 percent since 2000 at the port of Ventspils in Latvia. Russian authorities have stated publicly that when allocating the country's exports, precedence will be given to sea ports in which Russia has a stake over foreign ones; in other words, BPS over other Baltic ports.

Kharyaga-Indiga and Murmansk

A new pipeline and deepwater tanker terminal in the Barents Sea would carry crude oil from Russia's West Siberian Basin and Timan-Pechora basin westward to Murmansk on the Barents Sea. Such a terminal would allow for 500,000 bbl/d of Russian oil exports to reach the United States via tankers within only nine days travel time, much faster than shipping from the Middle East or Africa. Liquefied natural gas (LNG) facilities at Murmansk and Arkhangelsk (to the southeast) also have been suggested, possibly allowing for natural gas exports to American markets.

Despite support for the Murmansk proposal from Russian oil companies, American oil companies, and the U.S. government, Transneft (and thereby the Russian government) has approached the project with caution. In January 2005, Transneft was considering a shorter western route with a terminus at Indiga instead of Murmansk, and Transneft's CEO (Chief Executive Officer) plainly said the Murmansk proposal had no future. Alekperov also said publicly that he believed the Murmansk project was no longer economically feasible and had not gained support from foreign or Russian private investors. At a cost of $6 billion, the new Indiga proposal is closer to the Timan-Pechora oil fields than the Murmansk pipeline.

Building the pipeline to Indiga, where in contrast to Murmansk the port is iced over during the winter, will still not happen anytime soon. Because the Russian government has given priority to the construction of the Taishet-Nakhodka pipeline, Transneft is reluctant to take on two large pipeline projects at the same time. Some Transneft officials and others have stated that Russia's expanding BP's system as well as a few other key export projects will be sufficient to keep pace with growing Russian oil production.

Работа с текстом D

Задание l6. Прочтите и письменно переведите текст.

TEXT D

Proposed OH Pipeline Routes and Pipeline Expansion Projects (Part II)

Adria Reversal Project

Reversal of the Adria pipeline, which spans between Croatia’s port of Omisalj on the Adriatic Sea and Hungary, has been under consideration since the l990s. The pipeline, which was completed in l974, was originally designed to load Middle Eastern oil at Omisalj, then pipe it northward to Yugoslavia and on to the Hungary. However, given both the Adria pipeline’s existing interconnection with the Russian system, and Russia’s booming production, the pipeline’s operators and transit states have since considered reversing the pipeline’s flow, thus giving Russia a new export outlet on the Adriatic Sea.

Connecting the Adria pipeline to Russia’s Southern Druzhba system would require the cooperation of six countries (Russia, Belarus, Ukraine, Slovakia, Hungary, and Croatia). In December 2002, these countries signed a preliminary agreement on the project. Since then, however, progress has been slow moving, while the transit states wrangle over the project’s details (including tariffs and environmental issues). Of the six partners, only three countries, Slovakia, Hungary and Ukraine are fully ready to implement the reversal. Croatia is particularly worried about the environmental effects of increased oil transports from a port along its coast. The Croatian government rejected the conclusions of an environmental impact study completed in October 2005, calling it ‘incomplete and not based on expert knowledge’. The rejection of the study’s findings could keep the project from ever getting underway. Given the relative simplicity of reversing the flow the countries should come to an agreement and some analysts expect that the Adria pipeline could begin transiting roughly 100,000 bbl/d of Russian crude in the first year of reversal (less than 3 % of Russian crude oil exports), with an ultimate capacity of approximately 300,000 bbl/d.

Eastern Siberia Pacific Ocean Pipeline (ESPO): Taishet Skovorodino - Perevoznaya Bay

For about two years, Russian energy officials were unwilling to commit one of two of transit pipelines to eastern Asia. Finally, in late 2004, President Putin announced that Russia would commit to building a pipeline route from the Russian city of Taishet to Perevoznaya Bay. Recently Putin and Transneft officials have clarified that the 2,500-mile pipeline will be built in two stages, initially to the Pacific coast where a new export facility is to be constructed. Russia estimates that the project will cost between $ll.5 and $l8 billion; and it will have a capacity of l.6 million bbl/d. The first stage of the pipeline to Skovorodino will cost around $6.6 billion; Transneft plans to borrow $5 billion through issue of Eurobonds and $l.6 billion through bank credits. Putin and Transneft have made the completion of the first stage a top priority and aim to have that stage of the pipeline constructed by late 2008. Oil would be shipped via rail to the Pacific coast until the second stage of the pipeline is constructed.

The route to Perevoznaya Bay is significantly more expensive than an alternative route to Daqing, China, since it covers a greater distance and involves more investment. However, the Taishet-Perevoznaya Bay route will open a new Pacific Port from which Russian oil exports could be shipped by tanker to other Asian markets and possibly even to North America. Although the Daqing option has been abandoned, it is still possible that China will import oil via the Perevoznaya route. Russian officials and Transneft executives reported in January 2005 that the Perevoznaya route would include a pipeline spur from Skovorodino (located about 30 miles from China).

Some hurdles exist to the Eastern Pipeline’s plan. First, financing the project is challenging. Russia has only obtained Japanese promises of $7 billion for the project. Also, the pipeline route passes close to the waters of Lake Baikal, a UNESCO - protected site, an environmental hurdles should therefore be expected. Perevoznaya Bay is also an environmentally sensitive area for whales and environmentalists have urged the terminus be closer to the industrial port of Nakhodka. Finally, the government estimates that transportation tariffs could be roughly $6 per barrel, but other outside analysts estimate the level at up to $l0 per barrel. It is also possible that the level of development of Eastern Siberian oil resources will not be sufficient to fill the pipeline to capacity by 2020.

Работа с текстом Е

Задание l7. Прочтите текст Е и переведите его без словаря.

TEXT E

Proposed Oil Pipeline Routes and Pipeline Expansion Projects (Part III)

Alternate Oil Export Routes

Rail exports comprise roughly 5 % of Russian crude oil exports. But unless significant investment flows into expanding the Russian pipeline network’s capacity, non-pipeline transported exports are poised (стремиться) to increase even more in the upcoming years. As China's growth continues, rail routes are the only way to provide Russian crude oil to East Asia. In the absence of a dedicated (предназначенный) pipeline route, Russian crude oil is exported via rail to the northeast cities of Harbin and Daqing and to Central China via Mongolia. Rail exports of crude oil to China will increase from approximately 200,000 bbl/d in 2005 to 300,000 bbl/d by 2006 according to China's Ministry of Railways. Outside observers have expressed concerns (беспокойство) that the government's treatment (обращение) of Yukos could affect the auction (аукцион, торг) of Yuganskneftegaz, Lukoil have taken over the role of rail supplier.

Oil Shipment: Black Sea

After Russian oil flows through the various pipelines described above, crude oil and products are shipped onward (вперед) to Europe, the United States via tanker. The bulk of Russia's oil is shipped to the Mediterranean (Средиземное море) and to Asia via tankers in the Black Sea, mostly from the port of Novorossiysk. With the opening of the BTC pipeline in early 2006 and the higher export aspirations (стремление) of the CPC (Caspian Pipeline Consortium) consortium owners, it is now unclear how much oil will still be shipped out of the Black Sea ports. Since the economic viability (жизнеспособность) of the BTC pipeline is yet untested, some analysts expect Novorossiysk (along with Batumi, Supsa and Odessa) to remain at current levels (approximately l.7 million bbl/d in 2003). Other analysts expect that if Azerbaijan does actually divert (отводить) all of its oil shipments via BTC, the exports from Novorossiysk will decrease. News reports indicate a floating (распространяемое) proposal that the Baku-Novorossiysk line might then be reversed, allowing for 250,000 bbl/d more crude oil exports to be sent from Russia to Baku and then along the BTC route. Also, the only area of expansion in the Russian pipeline network is near St. Petersburg, and the Baku-Novorossiysk line is the only one with spare (свободный) capacity.

Задание l8. Представьте, что:

l. Вы являетесь членом российской делегации на форуме стран-членов ОПЕК Вам поручено выступить с обзорным докладом по проблемам добычи нефти в России. Что бы Вы отметили в своем докладе.

2. Вы – член совета директоров компании Транснефть. Расскажите о проблемах экспорта российской нефти.

3. Вы – начальник отдела перспективного планирования компании Транснефть. Дайте характеристику существующим и перспективным маршрутам транспортировки нефти.

SUPPLEMENTARY READING

Text 1

Task 1. Read and translate the text

The Production Facility

The job of a production facility is to separate the well stream into three components, typically called "phases" (oil, gas, and water), and process these phases into some marketable product(s) or dispose of them in an environmentally acceptable manner. In mechanical devices called "separators" gas is flashed from the liquids and "free water" is separated from the oil. These steps remove enough light hydrocarbons to produce a stable crude oil with the volatility (vapor pressure) to meet sales criteria. Typical separators used to separate gas from liquid or water from oil can be either horizontal or vertical in configuration. The gas that is separated must be compressed and treated for sales. Compression is typically done by engine-driven reciprocating compressors. In large facilities or in booster service, turbine-driven centrifugal compressors are used. Large integral reciprocating compressors are also used. Usually, the separated gas is saturated with water vapor and must be dehydrated to an acceptable level (normally less than 7 lb/MMscf). Usually this is done in a glycol dehydrator.

Dry glycol is pumped to the large vertical contact tower where it strips the gas of its water vapor. The wet glycol then flows through a separator to the large horizontal reboiler where it is heated and the water boiled off as steam. In some locations it may be necessary to remove the heavier hydrocarbons to lower the hydrocarbon dew point. Contaminants such as H_2S and CO_2 may be present at levels higher than those acceptable to the gas purchaser. If this is the case, then additional equipment will be necessary to "sweeten" the gas. The oil and emulsion from the separators must be treated to remove water. Most oil contracts specify a maximum percent of basic sediment and water (BS and W) that can be in the crude. This will typically vary from 0.5% to 3% depending on location. Some refineries have a limit on salt content in the crude, which may require several stages of dilution with fresh water and subsequent treating to remove the water. Typical salt limits are 10 to 25 pounds of salt per thousand barrels.

Typical direct-fired heater-treaters that are used for removing water from the oil and emulsion being treated can be either horizontal or vertical in configuration and are distinguished by the fire tube, air intakes, and exhausts that are clearly visible. Treaters can be built without fire tubes, which makes them look very much like separators. Oil treating can also be done by settling or in gunbarrel tanks, which have either external or internal gas boots.

Production facilities must also accommodate accurate measuring and sampling of the crude oil. This can be done automatically with a Lease Automatic Custody Transfer (LACT) unit or by gauging in a calibrated tank. The water that is produced with crude oil can be disposed of overboard in most offshore areas, or evaporated from pits in some locations onshore. Usually, it is injected into disposal wells or used for waterflooding. In any case, water from the separators must be treated to remove mall quantities of produced oil. If the water is to be injected into a disposal well, facilities may be required to filter solid particles from it.

Water treating can be done in horizontal or vertical skimmer vessels, which look very much like separators. Water treating can also be done in one of the many proprietary designs such as upflow or downflow CPIs, flotation units, crossflow coalescers/separators, and skim piles. Skim tanks with and without free flow turbulent coalescers (SP Packs) can also be used. Any solids produced with the well stream must also be separated, cleaned, and disposed of in a manner that does not violate environmental criteria. Facilities may include sedimentation basins or tanks, hydrocyclones, filters, etc. The facility must provide for well testing and measurement so that gas, oil, and water production can be properly allocated to each well. This is necessary not only for accounting purposes but also to perform reservoir studies as the field is depleted.

Task 2. Put the sentences in order they appear in the text.

1. The oil and emulsion from the separators must be treated to remove water.
2. In mechanical devices called "separators" gas is flashed from the liquids and "free water" is separated from the oil.
3. Water from the separators must be treated to remove mall quantities of produced oil.
4. Dry glycol is pumped to the large vertical contact tower where it strips the gas of its water vapor.
5. Facilities may include sedimentation basins or tanks, hydrocyclones, filters, etc.
6. If the water is to be injected into a disposal well, facilities may be required to filter solid particles from it.
7. Compression is typically done by engine-driven reciprocating compressors.
8. Water treating can be done in horizontal or vertical skimmer vessels.

Text 2

Task 1. Read and translate the text

Controlling the Process

Operation of a control valve. Control valves are used throughout the process to control pressure, level, temperature, or flow. All control valves have a variable opening or orifice. For a given pressure drop across the valve, the larger the orifice the greater the flow through the valve.

Chokes and other flow control devices have either a fixed or variable orifice. With a fixed pressure drop across the device (i.e., with both the upstream and downstream pressure fixed by the process system) the larger the orifice the greater the flow. The orifice is made larger by moving the valve stem upward. This moves the plug off the seat, creating a larger annulus for flow between the seat and the plug. Similarly, the orifice is made smaller by moving the valve stem downward. The most common way to affect this motion is with a pneumatic actuator. Instrument air or gas applied to the actuator diaphragm overcomes a spring resistance and either moves the stem upward or downward. The action of the actuator must be matched with the construction of the valve body to assure that the required failure mode is met. That is, if it is desirable for the valve to fail closed, then the actuator and body must be matched so that on failure of the instrument air or gas, the spring causes the stem to move in the direction that blocks flow (i.e., fully shut). This would normally be the case for most liquid control valves. If it is desirable for the valve to fail to open, as in many pressure control situations, then the spring must cause the stem to move in the fully open direction.

Pressure control. The hydrocarbon fluid produced from a well is made up of many components ranging from methane, the lightest and most gaseous hydrocarbon, to some very heavy and complex hydrocarbon compounds. Because of this, whenever there is a drop in fluid pressure, gas is liberated. Therefore, pressure control is important. The most common method of controlling pressure is with a pressure controller and a backpressure control valve. The pressure controller senses the pressure in the vapor space of the pressure vessel or tank. By regulating the amount of gas leaving the vapor space, the backpressure control valve maintains the desired pressure in the vessel. If too much gas is released, the number of molecules of gas in the vapor space decreases, and thus the pressure in the vessel decreases. If insufficient gas is released, the number of molecules of gas in the vapor space increases, and thus the pressure in the vessel increases. In most instances, there will be enough gas separated or "flashed" from the liquid to allow the pressure controller to compensate for changes in liquid level, temperature, etc., which would cause a change in the number of molecules of gas required to fill the vapor space at a given pressure. However, under some conditions where there has been only a small pressure drop from the upstream vessel, or where the crude GOR (gas/oil ratio) is low, it may be necessary to add gas to the vessel to maintain pressure control at all times. This is called "make-up" or "blanket" gas. Gas from a pressure source higher than the desired control pressure is routed to the vessel by a pressure controller that senses the vessel pressure automatically, allowing either more or less gas to enter the vessel as required.

Level control. It is also necessary to control the gas/liquid interface or the oil/water interface in process equipment. This is done with a level controller and liquid dump valve. The most common form of level controller is a float, although electronic sensing devices can also be used. If the level begins to rise, the controller signals the liquid dump valve to open and allow liquid to leave the vessel. If the level in the vessel begins to fall, the controller signals the liquid dump valve to close and decrease the flow of liquid from the vessel. In this manner the liquid dump valve is constantly adjusting its opening to assure that the rate of liquid flowing into the vessel is matched by the rate out of the vessel.

Temperature control. The way in which the process temperature is controlled varies. In a heater, a temperature controller measures the process temperature and signals a fuel valve to either let more or less fuel to the burner. In a heat exchanger the temperature controller could signal a valve to allow more or less of the heating or cooling media to bypass the exchanger.

Flow control. It is very rare that flow must be controlled in an oil field process. Normally, the control of pressure, level, and temperature is sufficient. Occasionally, it is necessary to assure that flow is split in some controlled manner between two process components in parallel, or perhaps to maintain a certain critical flow through a component. This can become a complicated control problem and must be handled on an individual basis.

Text 3

Task 1. Read and translate the text

BASIC SYSTEM CONFIGURATION

Wellhead and Manifold. The production system begins at the wellhead, which should include at least one choke, unless the well is on artificial lift. Most of the pressure drop between the well flowing tubing pressure (FTP) and the initial separator operating pressure occurs across this choke. The size of the opening in the choke determines the flow rate, because the pressure upstream is determined primarily by the well FTP, and the pressure downstream is determined primarily by the pressure control valve on the first separator in the process. For high-pressure wells it is desirable to have a positive choke in series with an adjustable choke. The positive choke takes over and keeps the production rate within limits should the adjustable choke fail. On offshore facilities and other high-risk situations, an automatic shutdown valve should be installed on the wellhead. (It is required by federal law in the United States.) In all cases, block valves are needed so that maintenance can be performed on the choke if there is a long flowline. Whenever flows from two or more wells are commingled in a central facility, it is necessary to install a manifold to allow flow from any one well to be produced into any of the bulk or test production systems.

Initial Separator Pressure. Because of the multicomponent nature of the produced fluid, the higher the pressure at which the initial separation occurs, the more liquid will be obtained in the separator. This liquid contains some light components that vaporize in the stock tank downstream of the separator. If the pressure for initial separation is too high, too many light components will stay in the liquid phase at the separator and be lost to the gas phase at the tank. If the pressure is too low, not as many of these light components will be stabilized into the liquid at the separator and they will be lost to the gas phase. It is important to understand this phenomenon qualitatively. The tendency of any one component in the process stream to flash to the vapor phase depends on its partial pressure. The partial pressure of a component in a vessel is defined as the number of molecules of that component in the vapor space divided by the total number of molecules of all components in the vapor space times the pressure in the vessel. Thus, if the pressure in the vessel is high, the partial pressure for the component will be relatively high and the molecules of that component will tend toward the liquid phase. As the separator pressure is increased, the liquid flow rate out of the separator increases. The problem with this is that many of these molecules are the lighter hydrocarbons (methane, ethane, and propane), which have a strong tendency to flash to the gas state at stock tank conditions (atmospheric pressure). In the stock tank, the presence of these large numbers of molecules creates a low partial pressure for the intermediate range hydrocarbons (butanes, pentane, and heptane) whose flashing tendency at stock tank conditions is very susceptible to small changes in partial pressure. Thus, by keeping the lighter molecules in the feed to the stock tank we manage to capture a small amount of them as liquids, but we lose to the gas phase many more of the intermediate range molecules. That is why beyond some optimum point there is actually a decrease in stock tank liquids by increasing the separator operating pressure.

Task 2. Decide if statements are true or false. Correct false statements.

1. The size of the opening in the choke determines the flow viscosity, because the pressure downstream is determined primarily by the well FTP.
2. If the pressure in the vessel is high, the partial pressure for the component will be relatively high.
3. As the separator pressure is decreased, the liquid flow rate out of the separator increases.
4. Because of the single-component nature of the produced fluid, the higher the pressure at which the initial separation occurs, the less liquid will be obtained in the separator.
5. For high-pressure wells it is desirable to have a positive choke parallel with an adjustable choke.
6. Beyond some optimum point there is actually a decrease in stock tank liquids by increasing the separator operating pressure.
7. On onshore facilities and other high-risk situations, an automatic shutdown valve should be installed on the wellhead.
8. By keeping the lighter molecules in the feed to the stock tank we manage to capture a small amount of them as liquids, but we lose to the gas phase many more of the high range molecules.
9. The tendency of any one component in the process stream to flash to the vapor phase depends on its partial pressure.
10. If the pressure for initial separation is high, too many light components will stay in the liquid phase at the separator and be lost to the gas phase at the tank.

Text 4

Task 1. Read and translate the text

Separator Operating Pressures

The choice of separator operating pressures in a multistage system is large. For large facilities many options should be investigated before a final choice is made. For facilities handling less than 50,000 bpd, there are practical constraints that help limit the options. A minimum pressure for the lowest pressure stage would be in the 25 to 50 psig range. This pressure will probably be needed to allow the oil to be dumped to a treater or tank and the water to be dumped to the water treating system. The higher the operating pressure the smaller the compressor needed to compress the flash gas to sales. Compressor horsepower requirements are a function of the absolute discharge pressure divided by the absolute suction pressure. Increasing the low pressure separator pressure from 50 psig to 200 psig may decrease the compression horsepower required by 33%. However, it may also add backpressure to wells, restricting their flow, and allow more gas to be vented to atmosphere at the tank. Usually, an operating pressure of between 50 and 100 psig is optimum. As stated before, the operating pressure of the highest pressure separator will be no higher than the sales gas pressure. A possible exception to this could occur where the gas lift pressure is higher than the sales gas pressure. In choosing the operating pressures of the intermediate stages it is useful to remember that the gas from these stages must be compressed. Normally, this will be done in a multistage compressor. For practical reasons, the choice of separator operating pressures should match closely and be slightly greater than the compressor interstage pressures. The most efficient compressor sizing will be with a constant compressor ratio per stage. Therefore, an approximation of the intermediate separator operating pressures can be derived from:

$$R = \left[\frac{P_d}{P_s}\right]^{1/n}$$

where R = ratio per stage
P_d = discharge pressure, psia
P_s = suction pressure, psia
n = number of stages

Once a final compressor selection is made, these approximate pressures will be changed slightly to fit the actual compressor configuration. In order to minimize interstage temperatures the maximum ratio per stage will normally be in the range of 3.6 to 4.0. That means that most production facilities will have either two- or three-stage compressors. A two-stage compressor only allows for one possible intermediate separator operating pressure. A three-stage allows for either one operating at second- or third-stage suction pressure, or two intermediate separators each operating at one of the two compressor intermediate suction pressures. Of course, in very large facilities it would be possible to install a separate compressor for each separator and operate as many intermediate pressure separators as is deemed economical.

Task 2. Sum up the information given in the text.

Text 5

Task 1. Read and translate the text

Lease Automatic Custody Transfer (LACT)

In large facilities oil is typically sold through a LACT unit, which is designed to meet API Standards and whatever additional measuring and sampling standards are required by the crude purchaser. The value received for the crude will typically depend on its gravity, BS+W content, and volume. Therefore, the LACT unit must not only measure the volume accurately, but must continuously monitor the BS+W content and take a sufficiently representative sample so that the gravity and BS+W can be measured. In a typical LACT unit the crude first flows through a strainer/gas eliminator to protect the meter and to assure that there is no gas in the liquid. An automatic BS+W probe is mounted in a vertical run. When BS+W exceeds the sales contract quality this probe automatically actuates the diverter valve, which blocks the liquid from going further in the LACT unit and sends it back to the process for further treating. Some sales contracts allow for the BS+W probe to merely sound a warning so that the operators can manually take corrective action. The BS+W probe must be mounted in a vertical run if it is to get a true reading of the average quality of the stream. Downstream of the diverter a sampler in a vertical run takes a calibrated sample that is proportional to the flow and delivers it to a sample container. The sampler receives a signal from the meter to assure that the sample size is always proportional to flow even if the flow varies. The sample container has a mixing pump so that the liquid in the container can be mixed and made homogeneous prior to taking a sample of this fluid. It is this small sample that will be used to convert the meter reading for BS+W and gravity. The liquid then flows through a positive displacement meter. Most sales contracts require the meter to be proven at least once a month and a new meter factor calculated. On large installations a meter prover is included as a permanent part of the LACT skid or is brought to the location when a meter must be proven. The meter prover contains a known volume between two detector switches. This known volume has been measured in the factory to ±0.02% when measured against a tank that has been calibrated by the National Bureau of Standards. A spheroid pig moves back and forth between the detectors as the four-way valve is automatically switched. The volume recorded by the meter during the time the pig moves between detectors for a set number of traverses of the prover is recorded electrically and compared to the known volume of the meter prover. On smaller installations, a master meter that has been calibrated using a prover may be brought to the location to run in series with the meter to be proven. In many onshore locations a truck-mounted meter prover is used. The sales meter must have a proven repeatability of ±0.02% when calibrated against a master meter or ±0.05% when calibrated against a tank or meter prover.

Text 6

Task 1. Read and translate the text

Compressors

Gas enters the first-stage suction scrubber. Any liquids that may have come through the line are separated at this point and the gas flows to the first stage. Compression heats the gas, so there is a cooler after each compression stage. At the higher pressure more liquids may separate, so the gas enters another scrubber before being compressed and cooled again. For example, gas from the intermediate pressure separator can be routed to either the second-stage or third-stage suction pressure, as conditions in the field change.

Gulf of Mexico accident records indicate that compressors are the single most hazardous piece of equipment in the process. The compressor is equipped with an automatic suction shut-in valve on each inlet and a discharge shut-in valve so that when the unit shuts down, or when an abnormal condition is detected, the shut-in valves actuate to isolate the unit from any new sources of gas. Many operators prefer, and in some cases regulations require, that an automatic blowdown valve also be installed so that as well as isolating the unit, all the gas contained within the unit is vented safely at a remote location. Compressors in oil field service should be equipped with a recycle valve and a vent valve.

Compressor operating conditions are typically not well known when the compressor is installed, and even if they were, they are liable to change greatly as wells come on and off production. The recycle valve allows the compressor to be run at low throughput rates by keeping the compressor loaded with its minimum required throughput. In a reciprocating compressor this is done by maintaining a minimum pressure on the suction. In a centrifugal compressor this is done by a more complex surge control system. The vent valve allows production to continue when the compressor shuts down. Many times a compressor will only be down for a short time and it is better to vent the gas rather than automatically shut in production.

The vent valve also allows the compressor to operate when there is too much gas to the inlet. Under such conditions the pressure will rise to a point that could overload the rods on a reciprocating compressor.

The two basic types of compressors used in production facilities are reciprocating and centrifugal. Reciprocating compressors compress the gas with a piston moving linearly in a cylinder. Because of this, the flow is not steady, and care must be taken to control vibrations. Centrifugal compressors use high-speed rotating wheels to create a gas velocity that is converted into pressure by stators.

Reciprocating compressors are particularly attractive for low horsepower (< 2,000 hp), high-ratio applications, although they are available in sizes up to approximately 10,000 hp. They have higher fuel efficiencies than centrifugals, and much higher turndown capabilities.

Centrifugal compressors are particularly well suited for high horsepower (>4,000 hp) or for low ratio (<2.5) in the 1,000 hp and greater sizes. They are less expensive, take up less space, weigh less, and tend to have higher availability and lower maintenance costs than recips. Their overall fuel efficiency can be increased if use is made of the high temperature exhaust heat in the process.

Task 2. Answer the questions.

1. Why is it necessary to have a cooler after each compression stage?
2. Why does the gas enter another scrubber before being compressed and cooled again?
3. What is the reason for equipping the compressor with an automatic suction shut-in valve on each inlet and a discharge shut-in valve?
4. What kind of valves should compressors in oil field service be equipped with?
5. What is the function of the recycle valve?
6. What allows a reciprocating compressor and a centrifugal compressor to be run at low throughput rates? Is there any difference?
7. What are the functions of the vent valve?
8. Under what conditions will the pressure rise to a point that could overload the rods on a reciprocating compressor?
9. What is the difference in the way reciprocating and centrifugal compressors compress the gas?
10. When is it preferable to use reciprocating or centrifugal compressors?

Text 7

Task 1. Read and translate the text

Gas Dehydrators

Removing most of the water vapor from the gas is required by most gas sales contracts, because it prevents hydrates from forming when the gas is cooled in the transmission and distribution systems and prevents water vapor from condensing and creating a corrosion problem. Dehydration also increases line capacity marginally.

Most sales contracts in the southern United States call for reducing the water content in the gas to less than 7 Ib/MMscf. In colder climates, sales requirements of 3 to 5 Ib/MMscf are common. The following methods can be used for drying the gas:

1. Cool to the hydrate formation level and separate the water that forms. This can only be done where high water contents (±30 Ib/MMscfd) are acceptable.

2. Use a Low-temperature Exchange (LTX) unit designed to melt the hydrates as they are formed. LTX units require inlet pressures greater than 2,500 psi to work effectively. Although they were common in the past, they are not normally used be-

cause of their tendency to freeze and their inability to operate at lower inlet pressure as the well FTP declines.

3. Contact the gas with a solid bed of $CaCl_2$. The $CaCl_2$ will reduce the moisture to low levels, but it cannot be regenerated and is very corrosive.

4. Use a solid desiccant, such as activated alumina, silica gel or molecular sieve, which can be regenerated. These are relatively expensive units, but they can get the moisture content to very low levels. Therefore, they tend to be used on the inlets to low temperature gas processing plants, but are not common in production facilities.

5. Use a liquid desiccant, such as methanol or ethylene glycol, which cannot be regenerated. These are relatively inexpensive. Extensive use is made of methanol to lower the hydrate temperature of gas well flowlines to keep hydrates from freezing the choke.

6. Use a glycol liquid desiccant, which can be regenerated. This is the most common type of gas dehydration system and is the one shown on the example process flowsheet.

In a typical bubble-cap glycol contact tower wet gas enters the base of the tower and flows upward through the bubble caps. Dry glycol enters the top of the tower, and because of the downcomer wier on the edge of each tray, flows across the tray and down to the next. There are typically six to eight trays in most applications. The bubble caps assure that the upward flowing gas is dispersed into small bubbles to maximize its contact area with the glycol. Before entering the contactor the dry glycol is cooled by the outlet gas to minimize vapor losses when it enters the tower. The wet glycol leaves from the base of the tower and flows to the reconcentrator (reboiler) by way of heat exchangers, a gas separator, and filters. In the reboiler the glycol is heated to a sufficiently high temperature to drive off the water as steam. The dry glycol is then pumped back to the contact tower. Most glycol dehydrators use triethylene glycol, which can be heated to 340°F to 400°F in the reconcentrator and work with gas temperatures up to 120°F. Tetraethylene glycol is more expensive but it can handle hotter gas without high losses and can be heated in the reconcentrator to 400°F to 430°F.

Task 2. Describe the process of glycol dehydration in a typical bubble-cap glycol contact tower.

Text 8

Task 1. Read and translate the text

Two-Phase Oil and Gas Separation

Produced wellhead fluids are complex mixtures of different compounds of hydrogen and carbon, all with different densities, vapor pressures, and other physical characteristics. As a well stream flows from the hot, high-pressure petroleum reservoir, it experiences pressure and temperature reductions. Gases evolve from the liquids and the well stream changes in character. The velocity of the gas carries liquid droplets, and the liquid carries gas bubbles. The physical separation of these phases is one of the basic operations in the production, processing, and treatment of oil and gas.

In oil and gas separator design, we mechanically separate from a hydrocarbon stream the liquid and gas components that exist at a specific temperature and pressure. Proper separator design is important because a separation vessel is normally the initial processing vessel in any facility, and improper design of this process component can "bottleneck" and reduce the capacity of the entire facility.

Separators are classified as "two-phase" if they separate gas from the total liquid stream and "three-phase" if they also separate the liquid stream into its crude oil and water components. This chapter deals with two-phase separators. In addition, it discusses the requirements of good separation design and how various mechanical devices take advantage of the physical forces in the produced stream to achieve good separation.

Separators are sometimes called "gas scrubbers" when the ratio of gas rate to liquid rate is very high. Some operators use the term "traps" to designate separators that handle flow directly from wells. In any case, they all have the same configuration and are sized in accordance with the same procedure.

Factors affecting separation. Characteristics of the flow stream will greatly affect the design and operation of a separator. The following factors must be determined before separator design:

• Gas and liquid flow rates (minimum, average, and peak)
• Operating and design pressures and temperatures
• Surging or slugging tendencies of the feed streams
• Physical properties of the fluids such as density and compressibility
• Designed degree of separation (e.g., removing 100% of particles greater than 10 microns)
• Presence of impurities (paraffin, sand, scale, etc.)
• Foaming tendencies of the crude oil
• Corrosive tendencies of the liquids or gas

Task 2. Sum up the information of the text.

Text 9

Task 1. Match the headings with the paragraph and title the text.

1. Vertical Separators
2. Horizontal vs. vertical vessel selection
3. Horizontal Separators

Task 2. Translate the text

1.___________________. Separators are designed in either horizontal, vertical, or spherical configurations. In a horizontal separator, the fluid enters the separator and hits an inlet diverter causing a sudden change in momentum. The initial gross separation of liquid and vapor occurs at the inlet diverter. The force of gravity causes the liquid droplets to fall out of the gas stream to the bottom of the vessel where it is collected. This liquid collection section provides the retention time required to let entrained gas evolve out of the oil and rise to the vapor space. It also provides a surge volume, if necessary, to handle intermittent slugs of liquid. The liquid then leaves the vessel through the liquid dump valve. The liquid dump valve is regulated by a level controller. The level controller senses changes in liquid level and controls the dump valve accordingly.

The gas flows over the inlet diverter and then horizontally through the gravity settling section above the liquid. As the gas flows through this section, small drops of liquid that were entrained in the gas and not separated by the inlet diverter are separated out by gravity and fall to the gas-liquid interface.

Some of the drops are of such a small diameter that they are not easily separated in the gravity settling section. Before the gas leaves the vessel it passes through a coalescing section or mist extractor. This section uses elements of vanes, wire mesh, or plates to coalesce and remove the very small droplets of liquid in one final separation before the gas leaves the vessel.

The pressure in the separator is maintained by a pressure controller. The pressure controller senses changes in the pressure in the separator and sends a signal to either open or close the pressure control valve accordingly. By controlling the rate at which gas leaves the vapor space of the vessel the pressure in the vessel is maintained. Normally, horizontal separators are operated half full of liquid to maximize the surface area of the gas liquid interface.

2. ____________________. In this configuration the inlet flow enters the vessel through the side. As in the horizontal separator, the inlet diverter does the initial gross separation. The liquid flows down to the liquid collection section of the vessel. Liquid continues to flow downward through this section to the liquid outlet. As the liquid reaches equilibrium, gas bubbles flow counter to the direction of the liquid flow and eventually migrate to the vapor space. The level controller and liquid dump valve operate the same as in a horizontal separator. The gas flows over the inlet diverter and then vertically upward toward the gas outlet. In the gravity settling section the liquid drops fall vertically downward counter to the gas flow. Gas goes through the mist extractor section before it leaves the vessel. Pressure and level are maintained as in a horizontal separator.

3. ______________________. Horizontal separators are smaller and less expensive than vertical separators for a given gas capacity. In the gravity settling section of a horizontal vessel, the liquid droplets fall perpendicular to the gas flow and thus are more easily settled out of the gas continuous phase. Also, since the interface area is larger in a horizontal separator than a vertical separator, it is easier for the gas bubbles, which come out of solution as the liquid approaches equilibrium, to reach the vapor space. Horizontal separators offer greater liquid capacity and are best suited for liquid-liquid separation and foaming crudes.

Thus, from a pure gas/liquid separation process, horizontal separators would be preferred. However, they do have the following drawbacks, which could lead to a preference for a vertical separator in certain situations:

1. Horizontal separators are not as good as vertical separators in handling solids. The liquid dump of a vertical separator can be placed at the center of the bottom head so that solids will not build up in the separator but continue to the next vessel in the process. As an alternative, a drain could be placed at this location so that solids could be disposed of periodically while liquid leaves the vessel at a slightly higher elevation.

In a horizontal vessel, it is necessary to place several drains along the length of the vessel. Since the solids will have an angle of repose of 45° to 60°, the drains must be spaced at very close intervals. Attempts to lengthen the distance between drains, by providing sand jets in the vicinity of each drain to fluidize the solids while the drains are in operation, are expensive and have been only marginally successful in field operations.

2. Horizontal vessels require more plan area to perform the same separation as vertical vessels. While this may not be of importance at a land location, it could be very important offshore.

3. Smaller, horizontal vessels can have less liquid surge capacity than vertical vessels sized for the same steady-state flow rate. For a given change in liquid surface elevation, there is typically a larger increase in liquid volume for a horizontal separator than for a vertical separator sized for the same flow rate. However, the geometry of a horizontal vessel causes any high level shut-down device to be located close to the normal operating level. In a vertical vessel the shutdown could be placed much higher, allowing the level controller and dump valve more time to react to the surge. In addition, surges in horizontal vessels could create internal waves that could activate a high level sensor.

It should be pointed out that vertical vessels also have some drawbacks that are not process related and must be considered in making a selection. These are:

1. The relief valve and some of the controls may be difficult to service without special ladders and platforms.

2. The vessel may have to be removed from a skid for trucking due to height restrictions.

Overall, horizontal vessels are the most economical for normal oil-gas separation, particularly where there may be problems with emulsions, foam, or high gas-oil ratios. Vertical vessels work most effectively in low GOR applications. They are also used in some very high GOR applications, such as scrubbers where only fluid mists are being removed from the gas.

Task 3. Describe advantages and limitations of each separator type.

Text 10

Task 1. Read and translate the text.

Spherical Separators and Other Configurations

Spherical Separators. The same four sections can be found in this vessel. Spherical separators are a special case of a vertical separator where there is no cylindrical shell between the two heads. They may be very efficient from a pressure containment standpoint but because (1) they have limited liquid surge capability and (2) they exhibit fabrication difficulties, they are not usually used in oil field facilities. For this reason we will not be discussing spherical separators any further.

Other Configurations. Cyclone separators are designed to operate by centrifugal force. These designs are best suited for fairly clean gas streams. The swirling action of the gas stream as it enters the scrubber separates the droplets and dust from the gas stream by centrifugal force. Although such designs can result in significantly smaller sizes, they are not commonly used in production operations because (1) their design is rather sensitive to flow rate and (2) they require greater pressure drop than the standard configurations previously described. Since separation efficiency decreases as velocity decreases, cyclone separators are not suitable for widely varying flow rates. These units are commonly used to recover glycol carryover downstream of a dehydration tower. In recent years, demand for using cyclone separators on floating facilities has increased because space and weight considerations are overriding on such facilities.

Two-barrel separators are common where there is a very low liquid flow rate. In these designs the gas and liquid chambers are separated. The flow stream enters the vessel in the upper barrel and strikes the inlet diverter. The free liquids fall to the lower barrel through a flow pipe. The gas flows through the gravity settling section and encounters a mist extractor en route to the gas outlet. The liquids drain through a flow pipe into the lower barrel. Small amounts of gas entrained in the liquid are liberated in the liquid collection barrel and flow up through the flow pipes. In this manner the liquid accumulation is separated from the gas stream so that there is no chance of high gas velocities re-entraining liquid as it flows over the interface. Because of their additional cost, and the absence of problems with single vessel separators, they are not widely used in oil field systems.

Another type of separator that is frequently used in some high-gas/low-liquid flow applications is a filter separator. These can be either horizontal or vertical in configuration. Filter tubes in the initial separation section cause coalescence of any liquid mist into larger droplets as the gas passes through the tubes. A secondary section of vanes or other mist extractor elements removes these coalesced droplets. This vessel can remove 100% of all particles larger than about 2 microns and 99% of those down to about ½ micron. Filter separators are commonly used on compressor inlets in field compressor stations, final scrubbers upstream of glycol contact towers, and instrument/fuel gas applications. The design of filter separators is proprietary and dependent upon the type of filter element employed.

In applications where there is very little liquid flow, often a horizontal separator will be designed with a liquid sump on the outlet end to provide the required liquid retention time. This results in an overall smaller diameter for the vessel.

Scrubbers. A scrubber is a two-phase separator that is designed to recover liquids carried over from the gas outlets of production separators or to catch liquids condensed due to cooling or pressure drops. Liquid loading in a scrubber is much lower than that in a separator. Typical applications include: upstream of mechanical equipment such as compressors that could be damaged, destroyed or rendered ineffective by free liquid; downstream of equipment that can cause liquids to condense from a gas stream (such as coolers); upstream of gas dehydration equipment that would lose efficiency, be damaged, or be destroyed if contaminated with liquid hydrocarbons; and upstream of a vent or flare outlet.

Vertical scrubbers are most commonly used. Horizontal scrubbers can be used, but space limitations usually dictate the use of a vertical configuration.

Task 2. Describe each type of the separator. What do they have in common and what way do they differ?

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