University of Alberta

TOWARDS EFFECTIVE DEVELOPMENT OF NIGERIA'S NATURAL GAS: LESSONS FROM ALBERTA

by

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DEDICATION

This thesis is dedicated to

God

and to

my children, Oluwadamilola and Oluwadamilare, who endured so I could excel.

ABSTRACT

Nigeria has a huge natural gas reserve, but to date this resource has been largely under-developed. This state of affair has impacted negatively on Nigeria's economic potential. In contrast, Alberta has benefitted immensely from its natural gas resource because it has effectively developed same.

This thesis advocates the effective development of Nigeria's natural gas resources. It examines the current frameworks for the development of natural gas in Alberta and Nigeria and outlines the concepts in the Alberta's framework that could be adopted by Nigeria. Three core regimes that promote the effective development of natural gas are utilized for the examination. They are: effective regimes for the acquisition of natural gas rights, for the conservation, and for the utilization of natural gas resources. Given climate change concerns and depletion in natural gas stock capital, this thesis also advocates the sustainable development of natural gas in Nigeria and Alberta.

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TABLE OF CONTENTS

Part 1:

Part 2: ALBERTA'S FRAMEWORK FOR NATURAL GAS DEVELOPMENT

PART 1

1 INTRODUCTION

Nigeria's natural gas resource is presently under-developed. While other countries endowed with this resource have advanced its development, Nigeria has not. This state of affair is not peculiar to Nigeria. For many decades after its discovery, natural gas was ranked as a poor cousin to crude oil. Oil men ignored its industrial importance and focused more on oil well drilling. In many areas, natural gas produced in association with crude oil was either flared or vented if it was too difficult and too costly to bring to the market. Even discovered non-associated natural gas was often wasted, as its discovery was more frequently seen as a nuisance.[1]

The problem was compounded by a lack of technology with which to utilize natural gas and the risks and costs associated with its production, storage, and transportation.[2] A lot of headway has however been made since its first useful discovery in 1821.[3] At present, the annual world consumption of natural gas exceeds 106.604 tcf,[4]

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[1] See M. Medici, *The Natural Gas Industry: A Review of World Resources and Industrial Applications* (London: Newnes-Butterworths, 1974) at 2 [Medici]. See also Arlon R. Tussing and Connie C. Barlow, *The Natural Gas Industry: Evolution, Structure, and Economics* (Massachusetts: Ballinger Publishing Company, 1984) at 9 & 25 [Tussing & Barlow].

[2] Natural gas was seen and, to a great extent, is still seen as a utility business rather than a commodity business like oil, as such, it does not follow the conventions of the oil business. There was no ready market for gas as the consumer had to install specific equipment to receive, use and handle it nor was there a standard price for it and so each developer had to optimize production and supply costs so that the gas supplied can be more competitive than its alternatives. In Nigeria, for example, the reasons that have been adduced for the non-utilization of its natural gas include the absence of a comprehensive gas infrastructure in the form of pipeline systems; the low domestic demand for gas, occasioned by low levels of industrialization; distance from overseas markets and the lack of an articulated natural gas policy which specifically addresses the need of the natural gas industry. See Adedolapo Akinrele, *Nigeria Oil and Gas Law*, (N.p: Oil, Gas & Energy Law Intelligence, 2005) at 82; Yinka Omorogbe, "Law and Investor Protection in the Nigerian Natural gas Industry" (1996) 14 J. Energy Nat Resources L. 179 at 192 [Omorogbe].

[3] See Medici, s*upra* note 1 at 1.

[4]See British Petroleum, "Statistical Review of World Energy 2009" online: BP <http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/reports_and_publications/statistical_energy_review_2008/STAGING/local_assets/2009_downloads/statistical_review_of_world_energy_full_report_2009.pdf> at 27.

and this accounts for more than 27% of world energy demand.[5] Further, its dwindling supply and, until recently, rising price has started to make a difference in the way it is utilized.[6] There is no doubt that natural gas now plays, and will continue to play a very important role in the field of energy. It will be necessary to effectively develop natural gas so that the citizenry can enjoy its benefit.

This thesis therefore advocates that Nigeria should effectively develop its natural gas resource. Effective development means the planned management of natural gas exploitation to achieve social and economic benefits.[7] Alberta, a jurisdiction with a fully developed natural gas sector, provides a useful model for effective development.[8] The thesis will examine the current frameworks for natural gas development in Nigeria and Alberta and the extent to which the concepts in Alberta's framework can be adapted to allow the effective development of Nigeria's natural gas resource.

To achieve the aim of this thesis, three core regimes that promote the effective development of natural gas will be utilized. They are: effective regimes for the

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[5] See EIA "International Energy Outlook 2007", Report No DOE/EIA-0484 May 2007, online: EIA <http://www.eia.doe.gov/oiaf/ieo/nat_gas.html>.

[6] See Barbara Lewis, "Gas Flaring Makes Less Economic Sense" Edmonton Journal (12 July 2007) E3.

[7] See Kevin Timoney & Peter Lee, "Environmental Management in Resource – Rich Alberta, Canada: First World Jurisdiction, Third World Analogue" (2001) 63 J. Envtl. Mgmt 387 at 388 [Timoney & Lee].

[8] Natural gas may be classified as conventional and non-conventional. Non-conventional gas is that which requires more costly technologies to extract, whereas "conventional gas requires traditional technologies, at a lower cost to extract. Examples of non-conventional gas resources are "coalbed methane", "shale gas", and "tight gas". Conventional gas can further be classified as associated or non-associated gas. When natural gas is found in association with crude oil, it can either be in a solution form (i.e. dissolved in the crude oil during its formation and accumulation and unavoidably produced with it) or as a gas cap gas (which is found in the interstices of rock directly overlying crude oil accumulations) and co-ordination of production of associated oil and gas is often necessary to optimize the value of the recovered oil or gas. The total amount of natural gas contained in the ground is unknown and cannot be accurately measured because it is located deep beneath the earth's surface, but it is geologically estimated that the world's proved reserve is a little over 6534.0 trillion cubic feet; compared with an estimated proved 1258.0 thousand million barrels for crude oil. Paul Mortensen *et al*, *Natural Gas in Canada and the United States… From wellhead to Burner-Tip* (Calgary: Canadian Energy Research Institute, 2004) at 1.1-1.2 [Mortensen]; D. R. Percy, ed., *Basic Oil & Gas Law: Cases and Materials*, 2006 ed., looseleaf (Alberta: Faculty of Law, University of Alberta, 2006) at 23 [Percy]; *Supra* note 4 at 6, 22.

acquisition of natural gas rights, for the conservation, and for the utilization of natural gas resources.

In view of the negative impact of mineral development on the environment and the rapid decline in fossil fuel reserves in the world, the desired threshold in the development of any mineral resource is that the resource be developed sustainably.[9] Sustainable development has been defined as "development that meets the needs of the present without compromising the ability of future generations to meet their own needs".[10]

Sustainable mineral development is therefore the ideal type of development. It is common knowledge that the development of natural gas has not been fully sustainable. Fortunately, the world has become aware of the importance of developing mineral resources sustainably. Most jurisdictions are taking steps to ensure that the development of their mineral resource is sustainable. Therefore, in addition to advocating the effective development of Nigeria's natural gas resource, this thesis will also advocate that Nigeria and Alberta develop their natural gas in a sustainable manner.

The objective of this thesis is accomplished in four parts. The first part includes this introduction and an overview of the development of natural gas in Nigeria and

[9]See generally, Adrian J. Bradbrook, *et al*., eds., *The Law of Energy for Sustainable Development* (Cambridge: Cambridge University Press, 2005) [Bradbrook]; Adrian J. Bradbrook & Richard L. Ottinger, eds., *Energy Law and Sustainable Development* (Gland: International Union for Conservation of Nature and Natural Resources, 2003) [Bradbrook & Ottinger]. See also Jay G. Martin & Ann L. McNaughton, "Sustainable Development: Impacts of Current Trends on Oil and Gas Development", (2004) 24 J. Land Resources & Envtl. L, 257 at 259 [Martin & McNaughton]; Joyce M. Kramer & Claude D. Johnson, "Sustainable Development and Social Development: Necessary Partners for the Future" (1996) 23 J. Soc. & Soc. Welfare 75 at 77 [Kramer & Johnson];

[10] See World Commission on Environmental Development, *Our Common Future* (Oxford: Oxford University Press, 1987) at 43 [Brundtland Report]. Another author defines Sustainable development as involving the use of resources at a rate that does not imply a reduction of real incomes in the future and that does not reduce the ecological diversity of natural systems or their regenerative capacity. See P.S. Elder, "Sustainability" (1991) 36 McGill L.J. 832 at 835. Sustainable development will be examined in detail in Part 4.

Alberta. The second and third parts respectively examine the current frameworks for the development of Alberta and Nigeria's natural gas. The last part embodies the examination of the applicability of Alberta's framework to Nigeria, the recommendations, and the concluding remarks.

2 Natural Gas in Nigeria and Alberta

The history of natural gas in Nigeria and Alberta shows surprising similarities. Both economies are highly dependent on revenues generated from the petroleum sector. Also, both jurisdictions discovered natural gas accidentally and flagrantly flared it. But while Alberta, which has a much smaller reserve of natural gas than Nigeria, has been able to reduce its gas flaring and effectively develop its natural gas resource, Nigeria still flares a large volume of its natural gas and has not fully developed same.

There are understandable reasons why Alberta formerly and Nigeria today, flared such large amount of gas. They include the government's overriding concern with the development of crude oil; the absence of an effective regulatory and administrative mechanism; the common belief that the supply of natural gas was so great as to be practically inexhaustible; the low price of natural gas compared to crude oil; the distance from markets that could really use the gas; the need for significant infrastructure to process and carry gas to a small local market that could not use all the gas and to distant markets that could use natural gas; and the need to construct major infrastructure to permit its use in nearby urban centers.[11]

[11] See generally David H. Breen, *Alberta's Petroleum Industry and the Conservation Board* (Edmonton: The University of Alberta Press, 1993) [Breen]; Sarah Ahmad Khan, *Nigeria: the Political Economy of Oil* (Oxford: Oxford University Press 1994) at 159-164 [Khan].

Nigeria is rich in mineral wealth, with crude oil and natural gas being the country's major mineral products.[12] As of January 2009, the country had a proven reserve of 36.2 billion barrels of crude oil, 184 trillion cubic feet ("tcf") of natural gas, and a remaining ultimate potential natural gas reserve of 600 tcf.[13] Although most of the country's gas reserve has been discovered accidentally in the search for crude oil, Nigeria is still widely referred to as a gas country with some oil in it.[14] Its economic growth is derived primarily from the petroleum sector, which accounts for 95% of the country's total export earnings, 25% of its gross domestic product ("GDP") and 75% of total government revenue.[15] Due to the importance of petroleum to Nigeria's economy, its decreasing price has led to a reduction of 8.5% of the country's GDP in 2009.[16]

Presently, Nigeria is the largest crude oil producer in Africa and the eleventh largest producer in the world.[17] With respect to natural gas, it has the seventh largest reserve of natural gas in the world and the largest in Africa.[18] Due to various reasons evaluated in this thesis, Nigeria has been unable to effectively develop her natural gas

[12] Apart from crude oil and natural gas, Nigeria's hydroelectricity accounts for 8% of its energy consumption mix. Though coal is not presently part of Nigeria's energy consumption mix, there is however an estimated reserve of 639 million metric tonnes of coal. See Ministry of Mines and Steel Development Nigeria, "Opportunities: the Coal Deposits of Nigeria", online: <http://www.msmd.gov.ng/Solid_minerals_sector/Coal.asp>.

[13] See Energy Information Administration, "Country Analysis Brief: Nigeria", online: EIA < http://www.eia.doe.gov/emeu/cabs/Nigeria/Background.html> [EIA]; Juliana Taiwo, "Ajumogobia: Country has Over 600 tcfs of Gas Reserve", *Thisday Online* (24 December 2008), online: Thisday Online <http://allafrica.com/stories/200812240147.html>.

[14] Yinka Omorogbe, "Law and Investor Protection in the Nigerian Natural gas Industry" (1996) 14 J. Energy Nat Resources L. 179 [Omorogbe]. See also, M. Eghre-Oghene & O. Omole, "The Economics of the Nigerian Liquified Natural Gas Project" (1999) 23:4 OPEC Review 303; "Nigeria in the Gas Age", Nigeria's Oil and Gas Monthly (September, 1998) at 10.

[15] Khan, *supra* note 11 at 2.

[16] See Nick Tattersall & Chijioke Ohuocha, "Nigerian 2009 Budget Deficit Seen at 8.5 pct –IMF" *Reuters UK* (19 May 2009), online: Thomson Reuters <http://uk.reuters.com/article/idUKLJ94795920090519>.

[17] See EIA, *supra* note 13.

[18] *Ibid*.

resource and this under-development has in no way helped her economy and citizenry.[19] Nigeria currently produces an estimated 1.9 tcf of natural gas per year, with an average of 850 billion cubic feet ("bcf") per year being flared or vented.[20] According to economic analysts, Nigeria has flared an amount of gas capable of paying off most of its national debt.[21]

Just like Nigeria, the province of Alberta, in Canada, is rich in mineral wealth. As of June 2009, Alberta's remaining established natural gas reserve was 39 tcf.[22] Its economic growth has also been from the petroleum sector, revenue derived from the development of natural gas being a major contributor.[23] This thesis seeks to examine the

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[19] According to Khan, the country has a weak economy that is burdened with foreign debt and beset by structural, particularly balance of payments problems, with over 60% of her population falling below the poverty line. See Khan, *supra* note 11; Alberta International and Intergovernmental Relations, "Nigeria-Alberta Relations", online: <http://www.international.gov.ab.ca/documents/Nigeria-AlbertaJuly2006.pdf> at 1; Nina Budina, Gaobo Pang & Sweder van Wijnbergen, "Nigeria's Growth Record: Dutch Disease or Debt Overhang?", (15 June 2007) online: The World Bank <http://siteresources.worldbank.org/INTDEBTDEPT/Resources/20061012_06.pdf> at 2[WB].

[20] Gas flaring occurs when the gas is ignited and emitted as carbon-dioxide rather than being produced. While venting, is the release of such natural gas to the atmosphere as methane. Since gas is mostly flared rather than vented, writers frequently resort to the use of "flaring" when writing about both acts. See Kris Christen, "Environmental Impacts of Gas flaring, Venting Add Up", (2004) 38 (24), Environ. Sci. Technol.., 480A.

[21] See Michael J. Economides, A.O. Fasina & B. Oloyede, "Nigeria Natural Gas: A Transition from Waste to Resource", (2004) 7:1 World Energy, online: World Energy <http://www.worldenergysource.com/articles/text/economides_WE_v7n1.cfm >. Recent figures compiled by the World Bank and U.S. National Oceanic and Atmospheric Administration (NOOA), shows that Nigeria is the world's 2nd gas flaring nation after Russia. See WB, "Bank-Led Satellite Imagery Sheds More Light on Gas Flaring Pollution", online: WB (27 August 2007) <http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTENERGY/0,,contentMDK:21454461~menuPK:336812~pagePK:64020865~piPK:149114~theSitePK:336806,00.html?cid=EXTNAg1>.

[22] See Alberta Department of Energy, "Natural Gas – Statistics", online: ADE <http://www.energy.gov.ab.ca/NaturalGas/727.asp> [ADE].

[23] See 2009-2010 *Annual Report of the Alberta Ministry of Energy*, (Edmonton: Alberta Department of Energy, 2009) at 18 [Annual Report]; See also Martin Kaga, "State and Provincial Regulation of Natural Resources Exploitation: Provincial Regulation of Natural resources Exploitation" (2002) 28 Can.-U.S. L.J. 357. Just like Nigeria, the decreasing price of natural gas has increased the province's 2009-10 budget deficit. See Government of Alberta, News Release, "Lower Natural Gas Prices Drive Deficit Higher: Province to Further Reduce Costs of Government, Offset Shortfall by Withdrawal from Sustainability Fund" (26 August 2009) online: Government of Alberta <http://www.alberta.ca/acn/200908/26755573D91FC-08C1-0886-A29AB3398F3C6303.html>.

factors that aid the development of Alberta's natural gas to discover what innovative assistance it can render to the effective development of the Nigerian natural gas resource.

3 SUMMARY

As mentioned in the introduction to this part, the next two parts of this thesis will examine the frameworks for natural gas development in Alberta and Nigeria. The three core regimes that promote the effective development of natural gas will be utilized for these examinations. The scheme of the next two parts will therefore be to first examine the regime for the acquisition of natural gas rights, and then examine the regimes for natural gas conservation and utilization.

PART 2

ALBERTA'S FRAMEWORK FOR NATURAL GAS DEVELOPMENT

1 INTRODUCTION

This part is divided into three main sections. The first section will examine the regime for the acquisition of natural gas in Alberta. In this section, the mineral ownership system in the province will be reviewed. The mode of acquiring natural gas rights is also examined. The main focus will be on acquisition from the Crown as it owns the bulk of the natural gas in the province, comparable to the fully state-owned ownership regime in Nigeria. The efforts to effect the conservation of natural gas in the province will be considered and the part will conclude with an examination of the natural gas utilization regime. The goal is to highlight how Alberta has been able to effectively develop its natural gas, so as to determine what methods, if any, Nigeria can adopt in its quest for the effective development of its natural gas.

Just as in Nigeria today, Alberta had a myriad of problems plaguing the development of its natural gas in the early days after its discovery. The history will be relevant to an understanding of what the province did wrong in the early days and the steps it took towards solving the problems, with a mind to advocating the solutions in Nigeria where similar problems are found to exist.

1.1 History and Development of Natural Gas in Alberta

The *Alberta Act*,[1] created the province of Alberta.[2] With an estimated population of 3,632,483 as of 1 January 2009, it is the fourth largest province in Canada.[3] As a result of its location, it has a cool and continental climate.[4] Natural resources have had a strong impact on the political, economic and social condition of the province. The first indication that petroleum and indeed natural gas existed in Alberta occurred in 1883. In 1914, crude oil was discovered along with natural gas in Turner Valley, southwest of Calgary. The Turner Valley field was thus the first substantial producer of natural gas.[5]

The second major discovery of oil and gas was not made until 1947 in Leduc, southwest of Edmonton.[6] This discovery marked the establishment of Alberta as a major oil and gas-producing province.[7] It is now home to a world-class natural gas resource

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[1] (1930), R.S.C. 1985, App. II, No. 20, s. 21.

[2] See Peter Hogg & Mark Heerema, "When the West was Won: A Brief History of Alberta's Natural Resources" at 138-143 in Michael Payne et al, eds., *Just Works: Lawyers in Alberta, 1907-2007* (Toronto: Irwin Law Inc., 2007) at 138-143[Hogg & Heerema].

[3] Government of Alberta, "Alberta Facts", online: Government of Alberta <http://alberta.ca/home/about_alberta.cfm>[GOA]; Travel Alberta Canada, "About Alberta", online: Travel Alberta Canada <http://www1.travelalberta.com/en-us/index.cfm?pageid=922>.

[4] Alberta lies between the 49th and 60th parallels of latitude north of the equator. As a result the area receives considerably less solar radiation than the equatorial regions. The reduction in solar radiation results in average temperatures considerably lower than areas to the south. There are however isolated cases, only found in the months of June, July and August, when the levels of solar radiation are highest. Winter temperatures all over the province can drop to minus forty degrees Celsius. See GOA, "Climate and Geography", GOA, online: <http://alberta.ca/home/90.cfm>; Alberta Heritage Community Foundation, "Climate of Alberta", online: Alberta Heritage Community Foundation < http://www.abheritage.ca/abnature/environmental/climate.htm> [AHCF].

[5] See John Bishop Ballem, *The Oil and Gas Lease in Canada*, 3rd ed. (Toronto, University of Toronto Press, 1999) at 11 [Ballem, Oil and Gas Lease]; Murray Dale, "A Salute to the People of the EUB", DVD (Calgary, Energy Resources Conservation Board, 2005) [Murray].

[6] See David H. Breen, *Alberta's Petroleum Industry and the Conservation Board* (Edmonton: The University of Alberta Press, 1993) at 245.

[7] See Ballem, Oil and Gas Lease, *supra* note 5. The world energy position enjoyed by Canada today is largely due to the energy resources of Alberta. Virtually all the natural gas consumed by Canadians is produced domestically, and Alberta is basically the primary source of that natural gas. According to Alberta Department of Energy, the province continues to be the Canadian leader in an extremely successful and expanding energy sector. 80% of Canada's known natural gas reserves are located within Alberta and in addition, it supplies about 80% of Canada's natural gas consumption needs. About half of all the homes in Canada use natural gas as the primary source of heating. The electricity generation, industrial, and

base, with a remaining established reserve of 39 tcf and an ultimate potential reserve of 87 tcf of conventional natural gas and 500 tcf of non-conventional natural gas, as at 2007.[8]

Natural gas did not take its rightful place as an important energy resource in the early years of its discovery in Alberta. Then, natural gas was regarded as a nuisance, as it was discovered in the search for the more lucrative oil.[9] Compared to oil, the method of processing and transporting natural gas to ready markets was much more cumbersome, as such it was mostly flared.[10]

Also, most of the oil and gas development, were carried out on private lands, especially in the Turner Valley field and the government fully recognized the property rights of these owners.[11] This recognition, coupled with the government's preoccupation with oil and gas exploration and development, rather than its conservation, affected the regulatory capacity of the government to stop the massive waste of gas on these private lands.[12] The tremendous waste, resulting from unrestricted operations, was soon apparent and became a matter of grave concern to the pubic.[13]

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commercial sectors also use significant amounts of natural gas. See Alberta Department of Energy, "What is Natural Gas?" online: ADE <http://www.energy.gov.ab.ca/NaturalGas/723.asp> [ADE].

[8] See ADE, "Natural Gas – Statistics", online: ADE < http://www.energy.gov.ab.ca/NaturalGas/727.asp> [Natural Gas Statistics]. Natural gas has been an important commodity in the economic health of Alberta and has represented the greatest portion of non-renewable resource royalty revenue to the province. According to the Department of Energy, the amount of natural gas that lies deep in the earth will meet much of the needs of Albertans, Canadians and Americans for many decades into the foreseeable future. This, according to the Department of Energy, does not include Alberta's non-conventional natural gas resource potential. See ADE, "Natural Gas", online: ADE <http://www.energy.gov.ab.ca/OurBusiness/Gas.asp> [Natural Gas].

[9] See generally *supra* note 6.

[10] To the end of 1946, 75% of the natural gas produced in the Turner Valley field was wasted. See *ibid*. at 237.

[11] See generally, *ibid*.

[12] *Ibid*.

[13] It became common knowledge that this finite resource, a potential source of great wealth to the province, was rapidly being depleted and the flared gas was having a negative impact on the environment. See *ibid*.

These concerns, and the government's realization of its right to legislate in the public interest, led to the enactment in 1932 of the *Turner Valley Gas Conservation Act*.[14] This Act was enacted to govern the methods and rates of production in the field, so as to curb the incessant waste of gas. The Turner Valley Gas Conservation Board was established to enforce its provisions and to specifically promote general conservation practices in the field.[15] The government also devised ways to store the excess produced gas and to extend the markets for it. By the time this regulatory framework was put in place, the vast majority of the gas produced in the Turner Valley field had been wasted.[16]

The significance of Turner Valley field is therefore to be found in the regulatory framework that emerged in the course of the field's development. This was the critical legacy carried forward into the next phase of petroleum development in Alberta.[17] Today, the province has substantially reduced its level of natural gas waste.[18] The next three sections will examine and reveal how Alberta has used the core regimes,[19] espoused in the introductory part, to achieve this reduction in gas flaring and the effective development of its natural gas. The regime for acquiring natural gas interests in the province will now be examined.

[14] S.A. 1932, c.6.
[15] *Ibid*., s. 4; *supra* note 6.
[16] See *supra* note 6 at 237.
[17] *Ibid*.
[18] See Energy Resources Conservation Board, News Release, "ERCB Report: Total Flaring and Venting of Solution Gas Drop 2.4% in 2007" (2 July 2008) [ERCB]; Lynda Harrison, "Developing Countries Learn from Alberta's Conservation Practices" *The Daily Oil Bulletin* (27 October, 2003) [Lynda Harrison].
[19] Effective regimes for the acquisition of natural gas rights, for the conservation, and for the utilization of natural gas resources.

2 ACQUSITION OF NATURAL GAS INTERESTS

An examination of the acquisition of natural gas interests necessarily entails a consideration of the ownership of the interest that is being acquired; a review of the ownership system will thus be conducted. It is instructive to note that whether natural gas is owned privately or by the Crown, the Alberta government regulates the exploration and production of mineral resources in the province.[20]

2.1 Ownership of Mineral Rights

There are two types of mineral ownership regime in Alberta - Crown and private ownership. Private ownership arose out of early Dominion government grants and other sources such as Railway grants. [21] Crown ownership, on the other hand, arose by virtue of the 1884 reservation of mines and minerals by the Federal government, creating government ownership. Federal ownership in mines and minerals was transferred to Alberta in 1930.

Through the *Natural Resources Transfer Agreement Act 1930,*[22] the Government of Canada, in order to place the prairie provinces (which include Alberta) in an equal

[20] Under the Canadian constitutional regime, the Federal Government and the 10 Provincial Governments share legislative powers. Generally, the power to regulate the exploitation of natural resources, and related commerce is within the jurisdiction of the Provincial Governments. However, where a particular commercial activity involves a recognized head of federal power such as inter-provincial or an international element, for example the export or taxation of oil or gas destined for export outside the country, the Federal Government has jurisdiction. See Part VI of *Constitution Act, 1867* (U.K.), 30 & 31 Vict., c.3, reprinted in R.S.C 1985, App. II, No. 5, s. 92 (1) (a)-(b), (2), (3), & (13) [*Constitution Act, 1867*]. This section gives provincial legislature the exclusive right to make laws in relation to the exploration, development, conservation, and management of non-renewable natural resources within their jurisdiction. See on this, John Bishop Ballem, "Oil and Gas Under the New Constitution" (1983) 61 Can. Bar Rev. 547 at 558 [Ballem, Under the New Constitution].

[21] David Percy, ed., *Basic Oil & Gas Law: Cases and Materials*, 2006 ed., looseleaf (Alberta: Faculty of Law, University of Alberta, 2006) at 5-6.

[22] S.C. 1930, c. 3. This was confirmed in the *Constitutional Act, 1982*, being Schedule B to the *Canada Act 1982* (U.K.), 1982, c. 11. See also Hogg & Heerema, *supra* note 2.

position with the other provinces of Confederation,[23] transferred all its proprietary interests in natural resources, other than those retained in areas of continuing federal ownership (such as national parks and Indian reserves) to these provinces.[24] The Act however imposed a restriction on the right of the receiving provinces; section 2 required the receiving provinces to recognize and carry out any contractual arrangements between the Federal government and its lessees without alteration of any terms of the contract.[25] As a result of which the Turner Valley Conservation Scheme was declared invalid.[26]

As a result of this distribution of ownership, the Alberta Crown now owns about 81% of the province's mineral rights, while the balance is held in freehold by individuals or corporations. The Federal government retains ownership of mineral rights in National Parks, on Military reserves and on Indian reserves, where the ownership is held on behalf of First Nations.[27]

2.2 Mode of Acquisition of Natural Gas Rights

In this subsection, the modes of acquiring natural gas rights in Alberta will be considered. Since the focus will mainly be on the acquisition of Crown interests, only a short review of the acquisition of private interests will be done.

[23] *Constitution Act 1867*, *supra* note 20, s. 117 had given the original provinces of Ontario, Quebec, New Brunswick, and Nova Scotia power to retain their public property not disposed of by the Act.
[24] See *supra* note 21.
[25] *Natural Resources Transfer Agreement Act 1930*, *supra* note 22.
[26] See *Spooner Oils Ltd v. Turner Valley Conservation Board*, [1933] S.C.R. 629 [*Spooner Oil*].
[27] See *supra* note 21 at 6; Hogg & Heerema, s*upra* note 2 at 6.

2.2.1 Acquisition of Private Interests

A private interest may be acquired by a transfer in fee simple or a lease.[28] In Alberta, the right to exploit oil and gas is commonly acquired by the lease.[29] The lease is chosen because it grants to the lessee a lesser interest than an outright fee simple conveyance and is also the instrument that best meets the requirements of both parties. It confers a sufficient grant and term to permit the operator to remove the minerals if any are discovered; it preserves for the mineral owner a continuing interest in the minerals by reserving a royalty; and it protects the interest of the mineral owner by imposing certain time limitations within which the operator must explore the land or lose the lease.[30]

2.2.2 Acquisition of Interests from the Crown

In order to enjoy economic benefit from its mineral resources, Alberta has resolved that publicly owned resources can be more efficiently developed by the private industry.[31] Notwithstanding private development, the government retains regulatory powers over the development of mineral resources in the province.[32] The terms upon

[28] Fee simple refers to ownership with unrestricted rights of disposition. While a lease refers to a right less than ownership, since the lessor's rights to deal with the property is restricted. See Ballem, Oil and Gas Lease, *supra* note 5 at 6.
[29] *Ibid*.
[30] See *ibid.* at 11. The common form of freehold lease in use for oil and gas disposition in Canada is a standard form of lease prepared by the Canadian Association of Petroleum Landsmen (CAPL 99) and also the Canadian Association of Petroleum Producers. These forms of leases came about as a result of the mineral lessees seeking to improve their position and also trying to counteract the strict interpretations placed by the courts on the wordings of the various clauses in the old leases. See James A. Maclean, "The 1990 CAPL Operating Procedure: An Overview of the Revisions" (1992) 30 Alta. L. Rev. 133.
[31] See Michael Crommelin, "Government Management of Oil and Gas in Alberta" (1975) XIII Alta. L.Rev. 146 [Crommelin]; Martin Kaga, "State and Provincial Regulation of Natural Resource Exploitation: Provincial Regulation of Natural Resource Exploitation" (2002) 28 Can.-U.S. L.J. 357 at 359 [Kaga].
[32] *Supra* note 20.

which these private enterprises obtain exploration and production rights determine the extent to which the government will be successful in developing its mineral resources.[33]

The Alberta Crown's mineral tenure system has been developed in several stages. It began with small prospecting permits in the early 1930s. In the late 1930s, petroleum and natural gas reservations in respect of large areas (up to 40,000 hectares) were introduced. In 1962, a third mode, which was intended to stimulate the development of shallow natural gas reserves in the southeastern part of the province, was introduced. This tenure, characterized by the petroleum and natural gas permit, allowed the holder, upon discovery of gas and completion of a drilling program, to convert the entire area of the permit to petroleum and natural gas leases. The fourth stage and present mode, which began in 1976, established petroleum and natural gas licenses and leases.[34] In 1998, the *Petroleum and Natural Gas Tenure Regulation* ("Tenure Regulation")[35] was promulgated to simplify the cumbersome and inefficient process that had characterized the process of converting licenses to leases.

The *Mines and Minerals Act* ("MMA")[36] provides for the disposition of the mineral resources[37] vested in the Crown in right of Alberta.[38] While this Act makes provisions for the acquisition of petroleum and natural gas interests, it does not make any provision in respect of the acquisition of surface rights.[39] Under the Act, the Minister of Energy may enter into a contract with any person or the Government of Canada or a

[33] Crommelin, *supra* note 31 at 150.
[34] Alastair R. Lucas & Constance D. Hunt, *Oil and Gas Law in Canada* (Toronto, Carswell, 1990) at 14.
[35] Alta. Reg. 263/97.
[36] R.S.A. 2000, c. M-17.
[37] *Ibid*., s. 1(1)(p) defines mineral resources as specifically including natural gas.
[38] *Ibid*., s. 2(a).
[39] Surface rights acquisitions are governed by the provisions of the *Public Lands Act*, R.S.A. 2000, c. P-40 and Regulations made thereunder.

province or territory respecting the recovery, processing and disposition of its minerals.[40] The Minister also has the power to approve the continuation of these contracts past their primary term.[41] The mineral rights are acquired pursuant to auctions that are carried out at regular intervals throughout the year.[42] The lands subject to auctions are posted at the request of persons who wish to acquire these rights.[43]

The MMA provides for two types of oil and gas contracts, the Petroleum and Natural Gas Licences ("Crown Licenses") and the Petroleum and Natural Gas Leases ("Crown leases").[44] A lease or license is defined in the Act as a deed granting rights to petroleum or natural gas, or both, and issued under the Act or the predecessor Act.[45] Natural gas is then defined as the production from any well that initially produces gas either alone or with oil at a gas-oil ratio of 1800:1 or higher, but does not include any production that may be recovered from any well that initially produces gas with oil at a lower gas-oil ratio.[46]

Crown Licenses are granted for exploration purposes and can last for an initial period of 2-5 years, depending on its location in the province.[47] Where the exploration yields exploitable natural gas, the licensee can produce under the terms of the license, which is automatically converted to a lease upon renewal.[48]

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[40] See MMA, *supra* note 36, s. 9(a)(i).
[41] *Ibid.*, s. 82 (10).
[42] *Ibid*., s. 16.
[43] *Ibid*.
[44] MMA, *supra* note 36, Part 4.
[45] *Ibid*., s. 80(1) (a) & (b).
[46] MMA, *ibid.*, s, 80. This definition impliedly recognizes an oil operator's right to use natural gas to produce its oil.
[47] 2 years in the Plains Region, 4 years in the Northern Region, or 5 years in the Foothills Region. See Tenure Regulation, *supra* note 35, s. 6(1).
[48] *Ibid*., s. 12.

Crown leases grant the outright right to drill for, recover and remove natural gas that are the property of the Crown in the licensed or leased area, subject to any exceptions expressed in them.[49] The lease is initially granted for a period of 5 years.[50] In order to get an extension, the lessee must demonstrate that the land is in a productive spacing unit and it must have drilled a well by the end of the term.[51] The lessee will then be given an additional year to get the well into a productive state.[52] The lease only continues to the lowest productive zone that the well had reached as at the expiration of the initial term; the remainder of the land reverts to the Crown.[53] This prevents large oil and gas producers from tying up the lands with shallow wells.

A consequence of the reversion to the Crown is that the deep gas rights may be granted separately from the shallow gas rights, thereby creating a split title. Apart from arising in the afore-mentioned way, split title also arise when crude oil, natural gas or bitumen rights in the same land area and geological zone are granted to separate interests.[54]

Split title is a thorny issue pervading the acquisition of oil and gas rights in Alberta. It was initially prevalent in the disposition of private interests,[55] but is now common with Crown dispositions. The economic interests of the different mineral rights

[49] *Ibid*., s. 4(1).
[50] MMA, *supra* note 36, s. 81(1).
[51] *Ibid*.; *supra* note 35, s. 15(1).
[52] Tenure Regulation, *ibid*., s. 16(1) & s. 17(6).
[53] *Ibid*., s. 14(6)(d).
[54] See *Alberta Energy Co. v. Goodwell Petroleum Corp. Ltd.*, [2003] A.J. No. 1207, para. 4.
[55] In the 1880's, the Canadian government gave the Canadian Pacific Railway 25 million acres of land as part of its mandate to help settle the west. In the mistaken belief natural gas was a worthless and noxious substance, the C.P.R. originally sold land to homesteaders, reserving "coal, petroleum and valuable stone". As a result, the railway held the rights to petroleum and the settlers held the rights to natural gas. See *ibid*., para. 34.

holders sometimes diverge, leading to conflicts between them.[56] A classic example is seen in *Borys v. Canadian Pacific Railway and Imperial Oil Ltd*. [Borys].[57] In resolving a dispute that had arisen from a private split title, the Privy Council held that petroleum and natural gas were separate substances and therefore, that the reservation of petroleum did not include natural gas. It, nevertheless, held that the holder of the petroleum right had a corollary right to produce initial gas-cap gas[58] incidental to the recovery of its petroleum.[59]

To avoid incidentally losing their gas cap to oil producers, the holders of natural gas rights in Alberta were motivated by the decision in *Borys* to drill for the gas in their land,[60] If the gas is removed, less oil can naturally be pushed to the surface and recovered, thereby sterilizing the recovery of the oil resource. [61]

The Supreme Court of Canada applied the *Borys*[62] decision in *Alberta Energy Co. v. Goodwell Petroleum Corp. Ltd*. [Goodwell][63] to resolve a split title conflict. The Court held that, irrespective of the provision of any applicable statute, the holder of the bitumen right could produce initial gas-cap gas incidental to its bitumen recovery, subject to the right of the holder of the natural gas to compensation.[64]

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[56] *Ibid*., para. 4, fn. 3.
[57] [1953] 2 W.L.R. (NS) 225.
[58] Gas-cap gas is the gas that directly overlies the oil in the same geological strata. The gas-cap gas acts as a pressure to push the oil to the surface. See *supra* note 54, para. 39.
[59] See *supra* note 57 at 232, 237.
[60] See *supra* note 6 at xli –li.
[61] *Supra* note 54, para. 40.
[62] *Supra* note 57.
[63] *Supra* note 54, para. 40.
[64] *Supra* note 54, para. 78. See also *Xerex Exploration Ltd. v. Petro-Canada*, where Petro-Canada was held liable to pay damages to Xerex when, without Xerex's permission, the former drilled beyond its shallow oil and gas right, into Xerex's deep right. [2005] A. J. No. 774.

Natural gas, oil and bitumen are valuable and scarce resources. The Energy Resources Conservation Board ("the Board"),[65] which is a successor of the Alberta Energy and Utilities Board,[66] regulates the conservation of the province's energy resources. Part of the Board's mandate is to promote the orderly economic development of these resources and to curtail waste in production.[67] Both of theses ends promote efficiency of exploitation aimed at the maximization of resource revenue. There is an undeniable economic element in this aim.[68]

The Board therefore encourages the development of these mineral resources by entering into overlapping natural gas, crude oil, and oil sands leases that confer broad, unrestricted recovery rights. Presently, it is not technologically possible to concurrently produce gas-cap gas and oil or gas-cap gas and bitumen without sterilizing the recovery of the oil or bitumen. The Board does not foresee the possibility of the development of a superior technology for the production of oil or bitumen after the production of the associated gas. Consequently, in determining which resource is to be preferred, the Board views future development with a frozen technological perspective, aimed at the maximization of resource exploitation. [69]

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[65] Established by s. 2 of the *Energy Resources Conservation Act*, R.S.A. 2000, c. E-10 [ERCA].
[66] Established by s. 2 of the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 [AEUBA]. Effective, January 1, 2008, the Alberta Energy and Utilities Board was realigned into two separate regulatory agencies: the Energy Resources Conservation Board and the Alberta Utilities Commission. See s. 80 of the *Alberta Utilities Commission Act*, S.A. 2007, c. A -37.2 [AUCA]. This change was made in order to reflect the changing face of regulation in Alberta and also to allow these bodies focus on two distinct, expanding, and increasingly complex segments of Alberta's economy. See ERCB, online: <http://www.eub.ca/eub/index.html>.
[67] *Oil and Gas Conservation Act*, R.S.A. 2000, c. O-6, s. 4, [OGCA]; *Oil Sands Conservation Act*, R.S.A. 2000, c. O-7, s. 3 [OSCA].
[68] See Jason Metcalf, "Waste in the Land of Plenty" (2007-2008) Alta. L. Rev. 227 at 237.
[69] ERCB, "EUB Inquiry - Gas/Bitumen Production in Oil Sands Areas", (March 1998) at 51, online: ERCB <http://www.ercb.ca/docs/Documents/decisions/1998/GasBitumen1998.pdf>.

According to the Board, wasteful operations are avoided by preferring a plan of development that allows for the greatest possible amount of recovery given the tools of recovery available today. Such a plan of development is not concerned with maximization of oil or bitumen recovery for the sake of oil or bitumen recovery, but is completely driven by the maximization of realized economic gain.[70] The Board indicates that it is not just physical waste that is at issue, but that economic sterilization is an equally unacceptable risk.[71]

To prevent physical waste and economic sterilization, the Board prohibits the concurrent production of oil or bitumen and its associated gas-cap gas until it is reasonably established that producing the gas would not jeopardize the recovery of the oil or bitumen.[72] To further ensure this, associated-gas producers are required to obtain the approval of the Board before producing such gas.[73] In practice, the Board never gives this approval until all the oil or bitumen in the formation has been recovered.[74]

The Alberta Court of Appeal in *Giant Grosmont Petroleums Ltd. v. Gulf Canada resources Ltd.* [Grosmont][75] makes the economic case more clearly by reiterating the rationale behind preferring bitumen production over natural gas production. The Court

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[70] See *supra* note 68.
[71] *Supra* note 69.
[72] See Allan L. McLarty & George V. Levine, "The Gas/Bitumen Dispute" (2004 -2005) 42 Alta. L.Rev. at 131.
[73] See OGCA, *supra* note 67, s. 39(f).
[74] In *Gulf Canada Resources Ltd. Request for the Shut-in of Associated Gas, Surmount Area*, the Crown had leased bitumen right to Gulf Canada Resources Ltd. and natural gas rights to companies in the Surmount Producers Group within the same geological zone. The Board found that natural gas production could likely affect bitumen recovery, but bitumen production would negligibly affect natural gas recovery and therefore ordered the shut-in of associated gas production within a 3 section buffer of Gulf's bitumen lease in order to stop the pressure depletion in the gas-cap. See Energy Resources Conservation Board [ERCB], "Shut-In Order Board Proceeding No. 960952" (3 April 2000), online: ERCB <http://www.ercb.ca/docs/applications/submissions/Phase3Proceedings/Shut-InOrderBoardProceedingNo960952.pdf>.
[75] [2001] A.J. No. 864.

held that it is not only the interests of the holders of the natural gas and bitumen rights that were at stake but that the Board also owes a duty to the people of Alberta to safeguard their interests by preserving mineral resources.[76] This interest is the huge amount of revenue that would be lost if the recovery of bitumen is sterilized through the initial or concurrent production of associated gas.[77] The Board however attempts to balance the competing interests of holders of gas, oil and bitumen rights, against the conservation of the province's mineral resources and the preservation of the ability to produce concurrent resources.

The Board, recognizing that the restriction on gas production might create undue hardship for the holders of natural gas rights, has put in place various schemes to alleviate such hardship. These schemes include the payment of compensation,[78] the provision of temporary assistance and the waiver of rentals.[79] Most of all, the Board has acknowledged that the current lease tenure system, where natural gas rights are leased separately from oil or bitumen rights, present a number of regulatory conflicts that needs to be resolved.[80] The existing shared ownership regime makes a resolution extremely

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[76] *Ibid*. at para. 45.

[77] The Board in its 2000-22 decision had indicated that the volume of Alberta's bitumen resource on the Surmount leases alone was 15 10^9 barrels [bbl], which exceeds by more than one hundred times the total of all light-medium crude oil produced in Alberta up to the end of 1998. Presently, Alberta ranks second, after Saudi Arabia, in terms of proven global crude oil reserves. About 99% of these reserves are found in Alberta's oil sands. At the end of 2008, Alberta's oil sands contained a remaining established reserve of 170.4 billion bbl of crude bitumen. See ERCB, Decision 2000-22, "Rescinding an Order to Produce Documents" (15 February 2007) at 6, online: ERCB <http://www.ercb.ca/docs/documents/orders/RescindingOrderProceeding960952.pdf>; ADE, "Facts and Statistics", online: ADE <http://www.energy.alberta.ca/OilSands/791.asp>.

[78] This is pursuant to its powers to pay compensation to persons who suffer loss by reasons of any orders made pursuant to the OGCA. See OGCA, *supra* note 67, s. 99(1); Authorization of Agreement between the Crown and Conoco Canada Resources Ltd. et al. OC No. 83/2002, 27 February 2002.

[79] ADE, "*Gas* Over Bitumen – Temporary Assistance", IL 2003-30 (October 2003), online: ADE <http://inform.energy.gov.ab.ca/Documents/Published/IL-2003-30.PDF>; ADE, "Gas Over Bitumen", IL 2004 -36 (31 December 2004), online: ADE <http://inform.energy.gov.ab.ca/Documents/Published/IL-2004-36.pdf>.

[80] *Supra* note 69 at 53.

difficult.[81] The recognition of this problem has resulted in the Alberta Department of Energy advising that natural gas rights in the oil sands zones in Application Areas set out in the ERCB Interim Directive ID 99-1[82] and subsequent amendments will be reserved from future dispositions.[83] This policy initially was put into place for a two year period but it has since been extended to an indefinite term.[84] This measure ensures that the split title issue is not exacerbated little else has been done to address the existing split title issues.[85]

It is noteworthy that oil and gas companies in partnership with Alberta government departments have set up a collaborative Gas Over Bitumen Steering Committee to find ways for the production of gas without causing significant risk to future bitumen recovery.[86] The Committee's final report is still being awaited.

2.2.2.1 Anatomy of Crown Leases

The Crown Natural Gas Lease is drawn in the form of a contract, which is binding and enforceable against the Crown.[87] The Crown has devised a way of incorporating terms in its leases that allow it to retain its proprietary right and to make future regulatory

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[81] See ERCB, "Decision 2003-023 - Chard Area and Leismer Field Athabasca Oil Sands Area - Applications for the Production and Shut-in of Gas" (18 March 2003) at 40, online: ERCB <http://www.ercb.ca/docs/Documents/decisions/2003/2003-023.pdf>.
[82] ERCB, Interim Directive, 99-1, "Gas/Bitumen Production in Oil Sands Areas Application, Notification, and Drilling Requirements", (3 February 1999), online: ERCB <http://www.ercb.ca/docs/ils/ids/pdf/id99-01.pdf>.
[83] ADE, "Petroleum & Natural Gas Agreements – Term Extensions, Postings & Private Sales in Oil Sands Areas – Natural Gas Rights", IL 2000-36 (15 December 2000), online: ADE <http://inform.energy.gov.ab.ca/Documents/Published/IL-2000-36.pdf>.
[84] See ADE, "Continued Restriction on Sale of Natural Gas Rights in the Athabasca Oil Sands Area", IL 2002-07 (25 February 2002), online: ADE <http://inform.energy.gov.ab.ca/Documents/Published/IL-2002-07.pdf>.
[85] *Supra* note 72 at 134.
[86] *Ibid*.
[87] See s. 9(a)(i) MMA, *supra* note 36. See also Rowland J. Harrison, "The Legal Character of Petroleum Licenses" (1980) 58 Can Bar Rev. 483 at 487-492 [Harrison].

changes. According to Crommelin, these terms achieve the result that the Crown does not fetter its future executive action irrespective of the nature of the lessee's interest under the lease.[88] Some of the terms are examined below.

i. Granting Clause

Although the nature of the interests granted by the Crown lease has not been judicially determined,[89] an examination of the method of creating the lease and the words of grant indicate that a property interest in the nature of a *profit á prendre* is contemplated. A *profit à prendre* refers to a right to take something from the soil owned by another. It is an interest that authorizes the removal of a substance contained in the land. The lessee does not acquire an absolute ownership interest in the land, but acquires a proprietary interest in the substances removed when the hydrocarbon has been brought to the surface.[90] The terms "lease", "grant" together with the words "exclusive right to drill for, win, work and recover the leased substances won, or recovered" in the leased area,[91] lead to this conclusion.[92]

The granting clause indicates that the Crown makes no guarantee of this interest to the lessee.[93] This means that, in respect of Alberta Crown leases, there is no guarantee of what you get and what you keep. It put the onus on the lessee to ensure it gets the

[88] Crommelin, *supra* note 31 at 153.
[89] The only judicial decision in this respect is the obiter dictum of the Alberta Supreme Court, where it was suggested that the Crown lease grants a *profit á prendre* just as in a freehold lease. See *Industrial Coal and Minerals Ltd v. Province of Alberta*, [1977] 5 A.R. 612, paras. 15 - 16 [Industrial Coal]. The Supreme of Court Canada had previously determined that a freehold oil and gas lease generally in use in Western Canada grants a *profit á prendre*. See *Berkheiser v. Berkheiser et al.* [1957] 7 D. L. R. (2d) 721 [Berkheiser].
[90] *Berkheiser, ibid.*
[91] The Crown lease provides that:… her Majesty grants to the lessee, in so far as her Majesty has the right to grant the same, the exclusive right to drill for and recover the leased substances within the location, together with the right to remove from the location any leased substances recovered…. See Alberta *Petroleum and Natural Gas Lease, habendum.*
[92] See David E. Thring, "Alberta, Oil and the Constitution" (1979) 17 Alta. L. Rev. 69 at 77; *Industrial Coal*, *supra* note 89 at para. 16.
[93] See *supra* note 91.

interest it seeks. This seemingly insecure title has however not affected the number of Crown oil and gas leases in the province. The Crown does not derive substantial revenue, by way of royalty, unless the leased substance is recovered.[94] The government, being trustees for the people of the province, therefore endeavors to convey a secure interest to those people who risk their money in providing the means to develop its natural gas resource.[95] The granting of an insecure title is not recommended for a government that is striving to develop it natural gas, as this will discourage potential investors.

ii. Compliance with Laws Clause

The Crown lease provides that the lessee shall comply with the provisions of the MMA and in the event of a conflict between the provisions of the lease and the Act, the latter shall prevail.[96] The lease further provides that any reference to legislation shall be construed as a reference to the MMA as amended from time to time, any replacement of that Act and any regulations or other subordinate legislation flowing from the Act.[97] What this means in essence is that under the lease, the Crown has the arbitrary power to set the rules governing the transaction thereby preventing the lessee from challenging any legislative change made by the Crown in future. In order for an aggrieved lessee to successfully challenge a future legislative change, it would have to prove that the change is either not in good faith or that it amounts to an expropriation.[98]

Considering that most government leases in other parts of the world provide for stability clauses in order to reassure prospective investors that the legal right to impose

[94] See consideration clause, below subsection iii.
[95] Harrison, *supra* note 87 at 507.
[96] *Supra* note 91, clause 3.
[97] *Ibid*., clause 1.
[98] *British Columbia v. Tener* [1985] 1 S.C.R 533.

future changes will not be abused, the inclusion of this kind of "instability" clause is strange indeed. The clause is however acceptable in the petroleum industry, perhaps because Alberta has a "proven government". This means that there is an established record to build confidence that the government will not in fact abuse its power.[99]

Since it gained control over its natural resources in 1930, the different governments in Alberta have recognized and given effect to agreements entered into by their predecessors.[100] These governments have also not enacted any bad faith or expropriatory laws that would deter prospective investors. It is comforting to note that although the Alberta Compliance Clause pertains to all the laws of the jurisdiction, it has generally been exercised in the tax, conservation and royalty rates areas.[101] The strength of this kind of "compliance with law" clause therefore lies in the confidence reposed in the Alberta government, making it unusable in an unproven government, so far as the oil and gas industry is concerned.

iii. Consideration Clause

The consideration paid in respect of a Crown lease consists of bonus bid payments, rentals, taxes, and royalties.[102] The main consideration is the royalty. It is an

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[99] Harrison, *supra* note 87 at 507-508.
[100] *Ibid*.
[101] Comments made by Prof. David Percy at the University of Alberta, Faculty of Law, Basic Oil and Gas Law Class, March 2007.
[102] Bonus bid payments are upfront lump-sum payments made by companies to the Crown for the right to explore, produce and develop natural gas resources, the subject of the lease. In 2006, the Alberta government generated CDN$2.46 billion from bonuses realised from its mineral rights agreements. The rental is more of a land management tool that serves two purposes. One, to cover the crown's administrative cost associated with managing the resource and two, to encourage the relinquishment of mineral rights where exploration or production is not being actively pursued. The annual rental prescribed for the Alberta lease is $3.50 per hectare, with a provision for reduction of the rental where natural gas is discovered. The two major types of taxes that apply to natural gas development are the Natural Gas Freehold Mineral Rights Tax and the Corporate Income Tax. See 2009-2010 *Annual report of the Alberta Ministry of Energy*, (Edmonton: Alberta Department of Energy, 2009) at 19, 28; ADE, "Royalty Information Briefing-Bonuses and Land Rental Fees" at 1, online: ADE

amount payable to the owner of a natural resource as compensation for the exploitation and development of a non-renewable natural resource.[103] Royalties to the province from natural gas and its byproducts are larger than royalties from crude oil and bitumen. In 2008-09, natural gas royalty accounted for approximately 49% of the province non-renewable resource revenue.[104]

The natural gas lease provides that the lessee shall pay on all recovered natural gas, a royalty at such rate(s) as prescribed or as may be prescribed by the Lieutenant Governor in Council. The lease further provides that the royalty is to be calculated free of any deduction.[105] The provisions of the MMA in respect of natural gas royalties can be found in the *Natural Gas Royalty Regulations,* 2002,[106] *Natural Gas Royalty Regulations*, 2009,[107] and the *Natural Gas Deep Drilling Regulations*.[108] Apart from these Regulations, there is also a plethora of governmental policies on natural gas royalties most of which are contained in the Ministry of Energy's Directives, Guidelines, and Information Letters.[109]

Alberta royalty structure for natural gas is an ad valorem royalty assessed on a sliding scale, where the rate changes depending on the price and the level of production

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<http://www.energy.gov.ab.ca/Org/pdfs/InfoSeries-Report5-Bonus.pdf>; *supra* note 21 at 7-8; ADE, Information Letter, 1990-16 "Amendment to the Mines and Minerals Act and General Regulation; Rentals and Tariff of Fees", (1 August 1990), online: <http://inform.energy.gov.ab.ca/Documents/Published/IL-1990-16.PDF>; ADE, "Oil and Gas Fiscal Regimes: Western Canadian Provinces and Territories" at 9-14, online: ADE <http://www.energy.gov.ab.ca/Tenure/pdfs/FISREG.pdf>; [Oil and Gas Fiscal Regimes].

[103] See Yinka Omorogbe, *Oil and Gas Law in Nigeria* (Lagos: Malthouse, 2001) at 71 [Omorogbe, *Oil and Gas Law in Nigeria*]; ADE, "Royalty Information Briefing - What are Royalties" at 1, online: ADE <http://www.energy.gov.ab.ca/Org/pdfs/InfoSeries-Report1-Royalty.pdf>.

[104] See Annual Report, *supra* note 102 at 20.

[105] *Supra* note 91, clause 4.

[106] Alta. Reg. 220/02.

[107] Alta. Reg. 221/08.

[108] Alta. Reg. 224/08.

[109] ADE, home page, online: <http://www.energy.gov.ab.ca/index.asp>.

of the natural gas.[110] The royalty system has grown from the early days of natural gas development in the province. In the early years, the royalty system was a fixed flat percentage similar to the United States' model. Following the oil price shock in the early 1970s, the royalty formula was modified to make it sensitive to change in prices. At that time, there was a distinction between "old production and "new" (Vintages).[111] In 1978, the royalty formula was made sensitive to the level of production from the well. The 1980s ushered the introduction of incentive programs in response to low prices.[112]

The current royalty rate is determined as the weighted average of the royalty rates for its components, with the rate cap at CDN$16.59 per one million British thermal unit ("BTU"), and the rate ranging from 5-50%.[113] Royalties on natural gas by-products (methane ethane, propane, butanes, and pentanes-plus) are related to the prices of the product and range from 40% for pentanes and 30% for butanes and propane.[114] A graduated adjustment, which can lower the royalty rate to 5%, is made for low producing wells.[115] There are also royalty incentives to support development of costly deep

[110] The royalty scales take into account fluctuating commodity prices by providing increased returns for Albertans when prices are high, while offering lower royalty rates when prices are low to promote continued investment and development. See ADE, "Royalty Information Briefing – Royalties, History & Description" at 1 online: ADE <http://www.energy.gov.ab.ca/Org/pdfs/InfoSeries-Report3-Formulas.pdf> [Royalty Briefing]; Premier Ed Stelmach, "The New Royalty Framework", (25 October 2007) online: <http://www.energy.gov.ab.ca/Org/pdfs/royalty_Oct25.pdf> [New Royalty Framework]; GOA, News Release, "Legislation to Implement New Royalty Framework Introduced" (6 November 2008).

[111] Alberta classified natural gas resources into old and new vintages based on the date of discovery of the reservoir. About 90% of Alberta's natural gas production is classified as New Gas discovered in 1974 or later. The royalty rate cap was just above $3.70 and the rate started at 15% of production and increased to 30% for new gas after the price reached $3.60 per gigajoule ("P/GJ") and 5% for old gas when the prices reach $2.20 P/GJ. A recent change in the royalty framework has now eliminated the vintage classification of reserve. See ADE, "Information on the New Royalty Framework", 2008 online: <http://www.energy.gov.ab.ca/NaturalGas/Gas_Pdfs/NRF_IB_Final_Oct_15.pdf> [Information on the New Royalty Framework]; *Natural Gas Royalty Regulations*, 2009, *supra* note 108; Royalty Briefing, *ibid*.

[112] Royalty Briefing, *ibid*.

[113] See ADE, News Release, "Highlights of Alberta's New Royalty Framework" (25 October 2007). See also, New Royalty Framework, *supra* note 110.

[114] See Information on the New Royalty Framework, *supra* note 111; *Natural Gas Royalty Regulations*, 2009, *supra* note 107, schs. 3-5.

[115] See *Oil and Gas Fiscal Regimes*, *supra* note 102.

reserves[116] and natural gas programs that seek to improve air quality through solution gas conservation.[117]

In Alberta, the formula adopted for calculating the Crown's royalty share is the Gas Cost Allowance Formula.[118] Under this formula, the lessee bears the costs of bringing gas to the surface. The value of gas for royalty purpose is however calculated not at the wellhead, as is the case with freehold leases, but at the tailgate, which is the point at which processed gas leaves the processing plant for distribution to market.[119] It is therefore necessary to deduct from the tailgate value, the costs of gathering, compressing and processing the Crown's royalty share.[120]

The new royalty framework is based on the recommendations of the panel that was struck to look into the adequacy or otherwise of the revenue derived from the

[116] There are royalty adjustments for an exploratory or development well that is drilled or deepened below a true vertical depth of 2500 metres. See *supra* note 108, s. 3(1); ADE, Information Letter, 2006-26, "Termination of the Deep Gas Royalty Holiday Program (DGRHP) and Implementation of a New Royalty Adjustment Program for Deep Marginal Gas Wells", (7 September 2006), online: ADE < http://inform.energy.gov.ab.ca/Documents/Published/IL-2006-26.pdf>; ADE, Information Letter, 1985-29, "Deep Gas Royalty Holiday Program", (11 July 1985), online: ADE <http://inform.energy.gov.ab.ca/Documents/Published/IL-1985-29.PDF>.

[117] For example, royalty adjustments on otherwise flared solution gas and injection credits. See *supra* note 108, Reg. 14, sch. 7 & Reg. 17; ADE, Information Letter, 1999-19, "Otherwise Flared Solution Gas Royalty Waiver Program", (11 June 1999), online: ADE < http://inform.energy.gov.ab.ca/Documents/Published/IL-1999-19.PDF >; ADE, "Sulphur Emission Control Assistance Program Guidelines", (7 February 2003), online: ADE <http://www.energy.gov.ab.ca/NaturalGas/Gas_Pdfs/SecapGuide.pdf>; ADE, Information Letter, 2004-33, "Innovative Energy Technologies Program", (December 15, 2004), online: ADE < http://inform.energy.gov.ab.ca/Documents/Published/IL-2004-33.pdf>; & ADE, "CO2 Projects Royalty Credit Program" (June 2003), online: ADE <http://www.energy.gov.ab.ca/Oil/pdfs/CO2_Projects_Credit_Prog.pdf.>. See also the transitional royalty rates offered by the Crown to promote new drilling, ADE, News Release, "Alberta to Offer Transitional Royalty Rate to Promote New Drilling" (19 November 2008)[Alberta to Offer Transitional Royalty Rate]; ADE, News Release, "Wells Commenced After November 19, 2008 Eligible for Transitional Royalty Rates" (24 November 2008).

[118] See Oil and Gas Fiscal Regimes, *supra* note 102.

[119] See Ballem, Oil and Gas Lease, *supra* note 5 at 168.

[120] *Ibid*. at 11.

province's mineral resources.[121] The panel had submitted that in comparison to other energy-producing jurisdictions,[122] the province was not receiving a fair share of energy development through the current royalties, taxes and fees regime and stated that its recommendations were intended to create a stable and sustainable royalty framework for the long term.[123]

According to Ed Stelmach, the premier of Alberta, the new regime will give stability and predictability to the oil and gas industry and also assure investors that Alberta will remain an internationally competitive and stable place to do business. The regime is also expected to increase the province's revenue by $1.4 billion in 2010, a 20% increase over currently projected revenues for that year.[124]

The current global economic crisis and low gas prices have frustrated this expectation.[125] Poor prices have led to decade low drilling activities throughout the province, consequently affecting its current and projected revenue.[126] As it is, the Crown has introduced transitional royalty rates and drilling incentive programs to encourage

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[121] The then royalty framework had been challenged by a number of studies. See on this, Amy Taylor et al., "When the Government is the Landlord: Economic Rent, Non-Renewable Permanent Funds, and Environmental Impacts Related to Oil and Gas Developments in Canada" online: Pembina Institute <http://pubs.pembina.org/reports/GovtisLLMainAug17.pdf> [Pembina, When the Government is the Landlord]. See also, *2006-2007 Annual Report of the Auditor General of Alberta*, (Edmonton, Auditor General of Alberta, 2007) vol. 1, Recommendations Nos. 9-12 on the inadequacy of royalties received by the government.

[122] For example Texas, Norway and Alaska. See Royalty Review Panel, *Our Fair Share: Report of the Alberta Royalty Review Panel* (18 September, 2007) at 7, online: Ministry of Finance <http://www.albertaroyaltyreview.ca/panel/final_report.pdf >.

[123] *Ibid*. This is even moreso as the OGCA, *supra* note 67, requires that the leasing and development of the Province's mineral resources be managed in such a manner as to maintain a competitive fiscal regime that will attract industry investment while ensuring Albertans receive a fair share of benefits from energy and mineral resources development.

[124] New Royalty Framework, *supra* note 110.

[125] As at September 4, 2009, a million BTU of natural gas sold for USD$2.73 U.S. See CNNMoney.com online: <http://money.cnn.com/data/commodities/>.

[126] See on this, Darcy Henton, "Province Sees Drilling Revenue Plummet; Low Natural Gas Prices Mean Exploration Budgets are Slashed along with Rig Jobs" *Edmonton Journal* (30 June 2009) A.1; Deborah Yedlin, "From Best *to* Worst in 12 Quick Months" *Calgary Herald* (16 July 2009) D; Dan Healing, "Oil is King, Natural Gas has Lost Bling, in Alberta Oilpatch" *Telegraph-Journal* (4 July 2009) C.6.

drilling.[127] Perhaps this might also be in response to the accusation of the industry that it acted in bad faith in radically making the recent royalty change and the fact that natural gas activities moved to British Columbia and Saskatchewan after the rate increase.[128]

2.3 Assessment

Based on the foregoing, it would appear that Crown leases contain terms that might deter prospective investors, thereby stunting the development of natural gas in the province; on the contrary, this has not been the case.[129] Rather, there is an increase in natural gas investment. According to Alberta Ministry of Energy, about $37.8 billion was invested in the upstream oil and gas industry in 2008.[130] The sector has grown so much that it was the number one revenue earner for the province in 2008.[131] There has however been a huge decline in investment since January, 2009, partly due to shifting investment to friendlier regimes in British Columbia and Saskatchewan and partly because of low prices.[132]

The power derived from the terms of the lease allowed the Crown to successfully impose a revised royalty system in 1974 to appropriate the bulk of the increased price of

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[127] Companies drilling certain new wells i.e. natural gas 1,000 to 3,500 metres in depth after January 1, 2009 has a one-time option of selecting new transitional royalty rates or the new royalty framework rates. All wells drilled between 2009 and 2013 that adopt the transitional rates are required to shift to the New Royalty Framework on January 1, 2014. See, Alberta to Offer Transitional Royalty Rate, *supra* note 118. See also ADE, News Release, "Province Extends Energy Incentive Programs; Moves Forward on Competitiveness Review" (25 June 2009); See Annual Report, *supra* note 102 at 15; "Alberta Unveils Incentives to Spur Oil and Gas Drilling", *CBC News* (4 Mar 2009), online: CBC News -Calgary < http://www.cbc.ca/canada/calgary/story/2009/03/04/drilling-incentives.html>.

[128] See Jeffrey Jones & Scott Haggett, "Alberta Government Heed Royalty-Hike Advice: Auditor" *Reuters Canada* (1 October 2007); Klemchuk J., "British Columbia's Gems - The Horn River Basin and Montney Play", online: JeriCan on Oil <http://www.jericanonoil.com/> (30 October 2009).

[129] According to Harrison, *supra* note 87 at 505, Alberta regime provides a striking illustration of sophisticated legal anticipation.

[130] See Annual Report, *supra* note 102 at 18.

[131] *Ibid.*

[132] See *supra* notes 126 & 128.

oil that resulted from the international events of 1973[133] and also to carry out the recent revision of its royalty regime.

In addition a proven, honest and responsible government means investors have sufficient confidence in the system to invest maximally.[134] In his excellent analysis of the legal character of provincial petroleum leases, Harrison pointed out that the very ability to include such terms in its leases is a measure of confidence that the legal mechanism will not be used arbitrarily.[135] In fact, the Crown acknowledges the input of private investors and therefore does not take arbitrary decisions that might scare them off. Harrison's analysis is therefore still as true today as it was in 1980 when it was made, as legislative and political developments have since supported his view in every respect, except perhaps for the recent royalty debate.

Notwithstanding the reduction in its current and projected royalty income as a result of the depressed gas prices, the province has derived substantial revenue from its natural gas disposition regime, a certain percentage of which it places in a non-renewable natural resources savings fund, the Alberta Heritage Savings Trust Fund, established in 1976 by the *Alberta Heritage Savings Trust Fund Act*.[136] This fund, which is valued at $14.0 billion, as at March 2009,[137] continues to generate interest payments which can be used to provide social services to present and also future Albertans who can no longer

[133] Harrison, *supra* note 87 at 506-507.
[134] Alberta has steadfastly honored its promise not to increase natural gas royalty rate arbitrarily. See on this Harrison *supra* note 87 at 507. The last major royalty changes before 2008 were made in 1993. See *supra* note 122.
[135] Harrison, *supra* note 87 at 508.
[136] RSA 2000, A-23.
[137] See 2008-*2009 Annual Report of the Alberta Heritage Savings Trust Fund* (Edmonton: Alberta Finance and Enterprise 2009) at 2.

benefit from the resource-generated revenue enjoyed by earlier Albertans.[138] Although non-renewable resource revenue is not being transferred to the fund as originally envisaged,[139] the fund still boasts of a substantial amount of income reserved for future generation.

This section highlights how the Alberta government was able to insert favorable terms in its leases and maximize its revenue because it enjoyed the confidence of investors. This revenue has in turn been well invested. The next section will examine the legal and regulatory framework for the conservation of natural gas in the province, with the aim of examining the extent to which it might be considered for use in Nigeria.

3 CONSERVATION OF NATURAL GAS

As noted in the previous part, oil conservation and natural gas conservation are intimately bound together as wastage or production of natural gas can contribute to wastage of oil. Most of the natural gas conservation regulations are found in the context of legislation that regulates oil exploitation and production. Therefore in the discussion of natural gas conservation, oil conservation may also be discussed, although there are several unique aspects of natural gas conservation.[140]

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[138] *Ibid*., preamble; Pembina, When the Government is the Landlord, *supra* note 121 at 36-37 .

[139] When the Fund was initially created, a set percentage of non-renewable resource revenue was transferred to the Fund. Transfers stopped after 1986 due to budget pressures from an economic slow-down in Alberta. It wasn't until March, 2005 that the government began making Heritage Fund contributions from budget surpluses, derived mainly from non-renewable resource revenue. As at March 2009, the government had transferred over $3.9 billion from surpluses to the Fund. See *supra* note 137 at 5; Pembina, When the Government is the Landlord, *supra* note 121 at 37 & 39.

[140] According to Breen, generally, natural gas waste has been associated with production beyond market demand. He also posits that although natural gas is important as a fuel in its own right, it can be of substantial importance in the production of crude oil: that the relationship of oil and gas is thus central to an understanding of the concerns that motivated the search for effective petroleum conservation measure in Alberta. See *supra* note 6 at l.

The petroleum industry defines conservation from the perspective that oil and gas are non-renewable resources, and that conservation should consist of the prevention of waste, encouragement of re-use where possible, and, in some cases, retardation of use.[141] Professor E.W. Zimmermann outlines the petroleum industry's concept of conservation as being based on two major objectives - the prevention of waste of oil and gas, through which the ultimate recovery of these products from their reservoirs is greatly increased; and the protection and adjustment of correlative property rights appertaining to each owner of land in an oil and gas pool.[142] Where these rights are properly protected and adjusted, it will prevent wasteful over-drilling by the different owners, thereby conserving the oil and gas in the pool.[143]

Alberta's concept of conservation involves the development of oil and gas resources in an efficient and orderly manner which, to the greatest extent possible, eliminates all economically avoidable waste.[144] The *Gas Resources Preservation Act* 1956,[145] provided that its intent, purpose and objective was to effect the preservation and conservation of the oil and gas resources of the province and to provide for their effective utilization having regard to the present and future needs of persons within the Province.[146] According to Dr. George Govier, a former chairman of the Board,[147]

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[141] See Maurice J. Sychuk, "Conservation: Is It Justified in the Public Interest?" (1968-1969) Alta. L. Rev. 355 at 356.
[142] See E.W. Zimmermann, *Conservation in the Production of Petroleum* (New Haven: Yale University Press, 1957) 24 (cited in Sychuk, *ibid*).
[143] See John S. Lowe, *Oil and Gas Law in a Nutshell*, (St. Paul Minn.: West publishing Co., 1995), at 14, [Lowe]; *supra* note 6 at xxx. The decision in *Ohio Oil Company v. Indiana* (177 U.S. 190) [Ohio Oil] led to the idea of "correlative rights" and the government's role in protecting them.
[144] *Supra* note 77.
[145] S.A. 1956, c. 19.
[146] *Ibid*., s. 4. See also the OGCA, *supra* note 67, s. 4, which states that its purpose is to effect the conservation of, and prevent the waste of, the oil and gas resources of Alberta, by providing for its economic, orderly and efficient development in the public interest. The general idea behind this purpose was to guide the vast discretion given to the Board in the ERCA, *supra* note 65.
[147] *Supra* note 65.

conservation involves the efficient use of natural resources, the development of these resources in such a way as to protect the interests of future generations, and the elimination of all economically avoidable waste.[148]

Modern ideas of conservation involve a transition to alternative renewable resources in an orderly fashion.[149] The examination below will therefore be with a view to determining whether Alberta's approach to conservation encompasses both the traditional and modern ideas of conservation.

3.1 Pre-Conservation Era

Oil and gas conservation regulations arose in response to specific problems, mostly typified by the application of the "rule of capture". Crude oil, natural gas and water are fugacious in nature, thus, according to the rule of capture, there is no liability for capturing oil and gas that drains from another's lands. The owner of a tract of land acquires title to the oil and gas that it produces from wells drilled thereon, though it may be proved that part of such oil and gas migrated from adjoining lands.[150] As Lord Porter

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[148] See G. W. Govier, 'Oil and Gas Conservation" (Paper presented to the Canadian Institute of Mining and Metallurgy, Western Annual Meeting, Vancouver, 1950), 1-2. Dr. Govier also stated that Alberta's conservation regulations were initially instituted to protect correlative rights and eliminate surface waste. But with improved technical knowledge of the behaviour of reservoirs came the development of the idea of elimination of waste and maximum recovery consistent with reasonable economy. See G. W. Govier, "The Administration of the Oil and Gas Conservation Act in Alberta" 7 Alta. L. Rev. (1969) at 341.

[149] See Klaus Bosselmann, "Ethical Implication" [Bosselmann] in Adrian J. Bradbrook, *et al*., eds., *The Law of Energy for Sustainable Development* (Cambridge: Cambridge University Press, 2005) 74 at 79 [Bradbrook]; Adrian J. Bradbrook & Ralph D. Wahnschafft, "International Law and Global Sustainable Energy Production and Consumption" [Bradbrook & Wahnschafft] in Bradbrook at 181; Ibibia Worika, "Energy Development and Utilization in Africa" [Worika] in Bradbrook, 326 & 343; Ibrahim Dincer & Marc A. Rosen, "Energy, Environment and Sustainable Development" (1999) 64 J. Applied Energy, 427 at 437 [Dincer & Rosen].

[150] There are inherent limitations to the application of this rule imposed by the doctrine of correlative rights and statutes. According to Lowe, the rule is inherently limited by its rationale. It was developed to encourage development of oil and gas resources for the benefit of the society. Its purpose therefore limits the scope of its protection. See Lowe, *supra* note 143 at 9. See also Bruce M. Kramer & Owen L. Anderson, "The Rule of Capture-an Oil and Gas Perspective" 35 Envtl. L. (2005) at 899 at 902; Borys, *supra* note 57; *Westmoreland & Cambria Natural gas Co. v. DeWitt et all*, 130 Pa. 225; Arlon R. Tussing

observed in *Borys,*[151] the logical solution to the application of this rule was for the owner of the adjoining land to drill an offset well and commence production as quickly as possible before more of its oil or gas was captured by others.[152] Nowhere was this played out more than in Alberta's Turner Valley oilfield. There, the oil producers' frenzied competition to lift as much oil as possible before their neighbor drew it, left little time to develop economic uses for the associated gas, which was therefore flared. [153]

Apart from natural gas waste caused by the application of the rule of capture, public use also contributed in no small measure to this waste. Commenting on the early custom of selling natural gas at so much per burner per month instead of at a fixed price to the public, Dr. Frank D. Adams, former dean of the Faculty of Applied Science at McGill University and the Chairman of the Sir Clifford Sifton Commission of Conservation,[154] Committee on Minerals, stated that the inevitable tendency of such practice was for the public to allow the gas in the street lamps to burn all day, seeing that it costs no more to do so, while at the same time it was easier to let it burn than to turn it

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& Connie C. Barlow, *The Natural Gas Industry: Evolution, Structure, and Economics* (Massachusetts: Ballinger Publishing Company, 1984) at 22 [Tussing & Barlow]; *supra* note 6 at xl-xlii.

[151] *Supra* note 57.

[152] *Ibid* at 227. See also *Ohio Oil, supra* note 143, for an insight to the problems that arose as a result of the application of this rule in the United States.

[153] Within three months of the discovery of oil and gas in the Turner Valley Oilfield, more than 400 companies had been granted provincial charters to drill for oil and gas in that same field. According to Breen, "the excesses of May, June and July 1914 would take almost a generation to erase". See *supra* note 6 at 16. According to the Committee on the Conservation and Utilization of Waste Gas in Turner Valley, Alberta, the result of the application of the rule of capture was an estimated loss of 59,000 cubic feet of gas per barrel of oil produced. This was 590 times greater than that of the California fields. See Report of the Committee on the Conservation and Utilization of Waste Gas in Turner Valley, Alberta, 8 January, 1930 (cited in Breen, *supra* note 6 at 60). Commenting on the waste in Turner Valley in 1932, a respected American consulting engineer stated that the waste in Turner Valley constituted by far the greatest waste of natural gas taking place in the continent. F.P. Fisher, "General Report of the Proposed Turner Valley Agreement", (Edmonton: 1932) at 6 (cited in Breen, *supra* note 6 at 652).

[154] See Canada Commission of Conservation, "Report of the First Annual Meeting", (Ottawa: Mortimer Company Ltd., 1910), pp.4-5.

out. That the spectacle of gas blazing throughout the day conveyed a general suggestion of abundance of a product which one could afford to waste so lavishly.[155]

3.2 Conservation Era

The *Petroleum and Natural Gas Regulations*, 1914[156] was the Federal government's[157] first attempt to curb the waste of natural gas in the Turner Valley field. It was more imperative to do this because although the conservation of natural gas was a legitimate concern in its own right, conservation of gas produced in connection with the production of petroleum was doubly important for it had a direct bearing on the amount of oil that could ultimately be produced from the reservoir.[158] Unfortunately, this Regulation was not seriously enforced as the government was content merely to identify measures to curb the waste, and for the following decade, the conservation measures outlined in the Regulation remained more a statement of desire rather than a required practice.[159] Notwithstanding its non-enforcement, the inclusion of the enabling provision

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[155] *Ibid*., pp. 68-69.

[156] Order-in-Council, P.C. No. 154, 19 January 1914. This Regulation was a direct result of the effort of the Sir Clifford Sifton Commission of Conservation, *ibid.*

[157] Before 1930, the natural resources of Alberta was owned and regulated by the Canadian Federal Government. See Section 2 above.

[158] See *supra* note 54, para. 40; A.A. Carpenter, former chairman of the Alberta Public Utility Commission, in PAA, Premiers' Papers, 18 December 1928, "Memorandum Re Wastage of Natural Gas in the Turner Valley Field," p.1 (Cited in Breen, *supra* note 6 at 57).

[159] According to Breen, *ibid*. at 23, Ottawa's overriding concern was with development of these resources, rather than conservation. There was wide-spread effort against the conservation movement by small independent producers of petroleum and natural gas, especially naphtha. (Naphtha is a lighter distillate of crude oil, which makes it very attractive to oil producers, as it could be pumped directly into the fuel tank of a car as gasoline, without laborious refining and more cost. See Tussing & Barlow, *supra* note 150 at 13). These producers were against conservation in its entirety, as they saw same as an attempt to deprive them of a share of the already small market. The Turner Valley gas field is what is known as a "wet field"; one where the natural gas coming to the surface holds crude naphtha in suspension. The practice of the operators in the field was to extract the naphtha from the natural gas by passing the gas through separators, and thereby effecting a liquefaction of the naphtha. For the natural gas produced in this field there was no sufficient market, and, since, to allow it to escape into the atmosphere (after the extraction of the naphtha) might endanger the health of people living in the vicinity, it was for the most part burned as refuse. Some of it was transported to Calgary and Lethbridge for consumption there in the production of light and heat; and some was used in refineries; but, while the ratio of the volume of gas consumed as waste to that which

in section 29 of the Regulation has proved remarkably enduring, as similar clauses in Alberta's subsequent oil and gas conservation Acts are the direct descendants of this section.[160]

Even during the era of Federal control, the Alberta Provincial Government attempted to establish conservation measures to curb the waste of oil and gas in all areas that did not come under the scope of existing federal regulation.[161] In 1926, it enacted the *Alberta Oil and Gas Wells Act*,[162] which gave conservation authorities the power to issue conservation regulations in specified areas. However, as a result of the anti-conservation movement of that period, none were ever issued.[163] At that time, demand for petroleum products was dropping and prices were in sharp decline. In this situation, small Turner Valley producers became even more resistant to any talk of curtailing production to effect conservation.

When the Canadian Federal government surrendered control of Alberta's natural resources in 1930,[164] Alberta attempted to put in place an effective conservation regime by enacting the *Oil and Gas Wells Act*[165] and the *Turner Valley Gas Conservation Act*,[166]

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is usefully consumed varied from month to month, very little more than 10% of what passed out of the wells was, except for the recovery of naphtha, applied to any useful purpose. See *Spooner Oil*, *supra* note 26 at 632-633.

[160] This section gives the minister of the interior the right from time to time to make such additional regulations as might appear to be necessary or expedient governing the manner in which boring operations shall be conducted, and the manner in which wells shall be operated. For example, in recognition that mere cancellation of a petroleum lease might be insufficient penalty for failure to take proper precaution to prevent the waste of natural gas, in 1919, the Minister of Interior, under the authority of s. 29 of the *Petroleum and Natural Gas Regulations*, *supra* note 156, announced more rigorous and operating regulations. See *supra* note 6 at 31.

[161] Namely, CPR and Calgary and Edmonton Railways lands, Hudson Bay Company lands, and homestead lands taken before 1887. See *supra* note 6 at 52.

[162] Statutes of Alberta, 1926, ch. 26, "An Act to provide for the Regulation of Oil and Gas Wells".

[163] *Supra* note 6 at 67 and 651.

[164] See the *Natural Resources Act*, S. A. 1931, c. 5; Hogg & Heerema, *supra* note 2.

[165] Statutes of Alberta, 1931, ch. 24, An Act Respecting Oil and gas Wells, "assented to 28, March 1931. Numerous regulations were proclaimed pursuant to this Act. For example, the Alberta Order-in-Council, OC No. 493-31, 6 May 1931 which ordered that the flow of gas, or gas and oil from every well in the province be restricted to 40% of its potential capacity, and Order-in-Council, OC No. 769-31, 10 July 1931,

which established a three-man Turner Valley Conservation Board to solve the "waste gas problem in the Valley.[167]

As mentioned earlier, a big blow was dealt to the province's first attempt to implement a comprehensive conservation program, by the Supreme Court of Canada decision in *Spooner Oil*.[168] The court held that though Alberta possessed the constitutional authority to enact conservation legislation, it had no right to impose conservation measures on lands held pursuant to contracts relating to lands, mines and minerals entered into with the Federal government before the transfer of control; a consequence of the express provincial obligation in the Natural Resources Transfer Agreement.[169] This decision meant that a significant portion of the lands held by the smaller independent oil producers in the Turner Valley Oilfield lay beyond the control of the Provincial Crown.[170] The implication of the decision was far reaching, as it shifted the province's focus from conservation to the broad issues of economic planning intended to counter the economic depression.[171]

The discovery of crude oil in the Turner Valley Royalties No.1 well in 1936 brought about renewed drilling in the field and a consequent increase in natural gas waste

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which was a comprehensive regulation respecting the drilling and production operations of oil and natural gas wells. See generally, *supra* note 6.

[166] S.A. 1932, c.6.

[167] *ibid.*, s.4. The first order made by the Board was in May, 1932. The order set an aggregate production maximum of 200 million cubic feet per day and prescribed a daily rate of permitted production for each well. See *ibid.*, s. 13. See also *supra* note 6 at 653.

[168] *Supra* note 26.

[169] S. 2 of the *Natural Resources Act*, *supra* note 164, provided that the province would honour the terms of leases from Dominion Government under Regulations of 1910 and 1911 (made under authority of Dominion Lands Act, 1908, c. 20) and would not affect or alter same by legislation or otherwise.

[170] Most of the lands in the Turner Valley oilfield were obtained under the Federal Regulations of 1910, *Regulations for the Disposal of Petroleum and Natural Gas Rights*, Order-in-Council, P.C. No. 414, 11 March, 1910. See *supra* note 6 at 7.

[171] *Ibid*., at 94.

and an oil glut as production exceeded market demand.[172] The province's efforts were then redirected towards persuading the Federal government to enact two legislative changes. First, was a law that would ensure that the oil and gas produced in Turner valley would be able to get a fair share of the Eastern Canadian market, which had been dominated by imports from the USA,[173] and the second was an appropriate amendment to the *Natural Resources Act*.[174] This was to ensure that Alberta's proposed comprehensive conservation legislation, the *Oil and Gas Resources Conservation Act*[175] could apply to all lands in the province, except national parks and Indian reserves, irrespective of the grantee of the rights to produce from the well.[176] Once the objective of the Crown was achieved,[177] conservation of Alberta's natural gas became a permanent and legitimate public concern.

3.3 Regulatory Authorities

The Energy Resources Conservation Board carries out its role in conjunction with the Ministry of the Environment ("Alberta Environment"). Their powers and responsibilities are examined below.

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[172] *Ibid*. at 103.
[173] The Federal Government's argument was that it would be too costly to transport oil and gas from the West to the East i.e. to build a pipeline). See generally *ibid*.
[174] *Supra* note 164.
[175] S.A. 1938 (2nd Sess.) c. 1, consolidated in R.S.A. 1942, c. 66. This Act was the successor to the *Turner Valley Gas Conservation Act*, *supra* note 166. It provided for the creation of a three-man Petroleum and Natural Gas Conservation Board to effect the conservation of the province's oil and natural gas resources and to enforce the provisions of the 1931 *Oil and Gas Wells Act*, *supra* note 165.
[176] See generally, *supra* note 6 at 109-121.
[177] The first objective was achieved by the amendment to the *Natural Resources Act*, 1931, *supra* note 164 by the *Natural Resources Act* S.A. 1938, c. 14. While the second objective was achieved by the pronouncement in 1961, of the national oil policy, which was to the effect that only western Canadian Oil could be sold west of the Ottawa valley. See *National Energy Board Act*, 1959, c.46, Part VI — Regulation 20 of Aug. 12, 1970 *and Caloil Inc. v. Canada (Attorney General)* (No. 2) [1970] Ex. C.R. 535.

3.3.1 Energy Resources Conservation Board

The Board is an independent quasi-judicial agency of the Government of Alberta with the responsibility to regulate Alberta's energy resources. While the Alberta Ministry of Energy has governance responsibilities for the Board, the Board makes its formal decisions independently in accordance with the provisions of various statutes and regulations.[178] Its mission is to oversee the efficient and effective development of the province's energy resources while balancing the need for resource conservation, public safety, environmental protection, customer service, and technical innovation.[179]

The Board's core businesses are adjudication and regulation, surveillance and enforcement, and the collection, analysis, storage, appraisal and dissemination of information and knowledge. It exercises regulatory, approval and policy-making functions, and advisory functions,[180] together with regulation-making powers under certain statutes.[181] Pursuant to those powers, the Board has published guidelines, directives, information letters, fact sheets and brochures to enable it effectively regulate these resources.[182] All these tools are intended to help oil and gas companies better understand the Board's expectations and requirements.

The Board consists of nine members, including the chairman, who are appointed by the Lieutenant Governor in Council. Each member holds office for an initial term of

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[178] Annual Report, *supra* note 102 at 7.
[179] See ERCB, "Transition of the Alberta Energy and Utilities Board into the Alberta Utilities Commission and the Energy Resources Conservation Board", Bulletin 2007-43, (Released: December 6, 2007), online: ERCB <http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_323_253_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/industry_zone/rules__regulations__requirements/bulletins/bulletin_2007_43.aspx>.
[180] See *supra* note 65, s. 2(g).
[181] For instance the power delegated to it under s. 10 of the OGCA, *supra* note 68. This regulation making power has been upheld by the Alberta Court of Appeal in *Grosmont*, *supra* note 76.
[182] See for example, *Exploration Regulation*, Alta. Reg. 284/2006, s. 29.

five years with a possibility of renewal.[183] The Lieutenant Governor fixes the remuneration of the members but the Board pays such remuneration.[184] The funding of the Board is statutorily regulated so as to ensure its independence.[185] Two-thirds of the fund it requires is obtained from a mandatory administrative fee applied to the oil and gas industry, while the remainder is received as grants from the provincial government.[186] Its business is conducted by a team of engineers, geologists, technicians, economists, and other professionals that serve Albertans from fourteen locations across the province.[187]

The Board has a wide discretionary power conferred on it by the various statutes under which it operates.[188] This power is limited by the requirement that it must give an annual account of its activities to the legislature and by judicial review of its decisions on law or jurisdiction.[189] However issues like the exercise of discretion are not usually discussed in the report and the Board cannot be sued for failing to exercise its discretion or for wrongful exercise of its discretion.[190]

The Board adopts a regulatory approach that includes public interest considerations, stakeholder consultation, adoption of a fair and objective standard, and acquisition of accurate and detailed information. It also adopts a public participation

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[183] See *supra* note 65, s. 5(1).
[184] *Ibid*. s. 5(5).
[185] *Ibid*. s. 27(1) & (2).
[186] *Ibid*. See also Annual Report, *supra* note 102 at 7.
[187] To ensure that there is no conflict of interest in carrying out its staff member's duties, the Board has a manual on Conflict of Interest Policy and Procedure. See ERCB, "Who We Are" online: ERCB <http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_299_260_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/about_the_ercb/who_we_are/>.
[188] See for example, ss. 10, 15 & 21 of the OGCA, *supra* note 67 & ss. 15 & 21 of the ERCA, *supra* note 65.
[189] See *supra* note 67, s. 41; Annual Report, *supra* note 102.
[190] See David Osigbemhe Iyalomhe, *Environmental Regulation of the Oil and Gas Industry in Nigeria: Lessons from Alberta's Experience* (LL.M. Thesis, University of Alberta, Faculty of Law, 1998) [Unpublished] at 94.

model in its adjudicatory process through its hearings.[191] Before the proclamation of the *Alberta Land Stewardship Act* [ALSA][192] in 2009, any order of the Board or its delegate was final and conclusive. Such orders were only subject to the judicial review provisions in sections 40 & 41 of the ERCA.[193] Now, the Board's orders must conform to the provisions of ALSA and its regulations.[194]

3.3.2 Ministry of the Environment

Although the Board has power under the ERCA[195] and OGCA[196] on environmental matters, measures to be taken to control pollution resulting from oil and gas operations require the approval of the Minister of the Environment.[197] Alberta Environment has statutory authority to regulate pollution resulting from oil operations in Alberta.[198] It does this through the approval of operations and the imposition of terms and conditions in relation to pollution control through such permits and approvals. All applications made by oil and gas operators to the Board for licenses or approval for oil

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[191] See *supra* note 65, s. 26. Hearing are not held in respect of every decision but only where the Board is of the view that the rights of the person may be adversely affected.
[192] S.A. 2009, A- 26.8.
[193] See *supra* note 65, s. 25. The Board's Order is only subject to judicial review on questions of law or jurisdiction. An appeal does not suspend the operation of the Board's Order, but if it thinks fit, the Board may suspend such Order pending the decision of the Court of Appeal. Subject to this judicial review by the Court of Appeal, no proceedings of, or before the Board may be restrained by injunction, prohibition or other court processes. Neither are they removable by certiorari or otherwise to any Court. This provision is similar to provisions in most Nigerian legislation that oust the jurisdiction of the Courts on decisions taken by the government or its agencies on oil and gas related matters. See *supra* note 190.
[194] The purpose of ALSA is to enable sustainable development by taking account of and responding to the cumulative effect of human endeavor and other events on Alberta's land, air and water, and also to provide a means to plan for the future, recognizing the need to manage activity to meet the reasonably foreseeable needs of current and future generations of Albertans. Under the ALSA, the government may establish integrated planning regions. Regional plans are given the status of regulations under the ALSA and all regulations under it prevail if inconsistent with other provincial regulations. Further, all statutory consents, like, approvals, licenses, and permits, of local governments, provincial departments, agencies and administrative bodies or tribunals, like the Board, must be reviewed and made to conform to ALSA and its regulations. See generally, *supra* note 192.
[195] *Supra* note 65, s. 25
[196] *Supra* note 67.
[197] See generally, *ibid*.
[198] See generally, *Environmental Protection Enhancement Act*, R.S.A. 2000 c. E-12 [*Environment Act*].

and gas related activities, including natural gas processing schemes, must be referred to Alberta Environment for review. The Minister may either order that no approval be issued in respect of that activity, it is not in the public interest to do so, or prescribe conditions that must be satisfied before such approval is given. [199]

In order to reduce bureaucratic wrangling and conflict, the Board and Alberta Environment co-ordinate their regulatory duties by providing an integrated and streamlined notification and reporting procedure for industry and the public through a "one-window approach".[200] They also provide for an improved inter-agency communication so as to optimize the efficient use of resources available to both agencies.[201]

3.4 Conservation Measures

Although oil and gas conservation are intimately bound together, their different physical properties create the need for slightly different conservation measures.[202]

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[199] *Ibid*. s. 62.

[200] The "one window approach" is intended to simplify and streamline the application process for the review and determination of environmental requirement under the various energy and environmental statutes implemented by the Board and the Alberta Environment. It involves sending of any application for approval to the Board, which acts as the window and the Board will in turn send such application to the Alberta Environment. The Alberta Environment will coordinate the participation of all government departments, compile any application deficiency requests of an environmental nature and then transmit same to the applicant through the Board. In all application for approval, the Board's staff normally draws the attention of the applicant to Alberta Environment's air and water quality standards that must be addressed in the application. See *supra* note 190 at 111-112.

[201] An example of such co-ordination is the memorandum of understanding between Alberta Environmental Protection and the Board. ERCB, Information Letter, 1998-1, "Memorandum of Understanding between Alberta Environmental Protection and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Responses" (6 February, 1998), online: ERCB <http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_323_253_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/industry_zone/rules__regulations__requirements/information_letters__interim_directives/informational_letters/il98_01.aspx>.

[202] Generally, natural gas is able to move much more easily from the reservoir to the surface. In addition, the productive capacity and ultimate recovery of natural gas reservoir is somewhat less sensitive than oil to varied production rate. See Paul Mortensen *et al*, *Natural Gas in Canada and the United States… From wellhead to Burner-Tip* (Calgary: Canadian Energy Research Institute, 2004) at 3.3.

Natural gas conservation measures are concerned both with preventing waste and with encouraging rational development. Some of the measures include: well spacing requirements;[203] prescription of maximum rates of production;[204] the limitation or distribution of the amount of gas that may be produced from a pool or part of a pool through rateable take regulations;[205] and the prevention of waste.[206] Because gas waste by flaring is the most prevalent conservation problem in Nigeria, only those measures dealing with the reduction will be examined.

3.4.1 Gas Flaring Reduction Schemes

Almost everywhere gas is produced, the flaring of gas is a common occurrence.[207] The regulation of gas flaring was initially to prevent its wastage; nowadays, it is also regulated because of environmental concerns.[208] Although the Board has the mandate to

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[203] Dense excessive drilling and high initial rate of production in most cases compromise ultimate recovery and add unnecessarily to reservoir development cost therefore representing an economic waste. See generally, *Oil and Gas Conservation Regulations*, Alta. Reg. 151/1971 ss. 4.010(1) & 4.020(2) [*Conservation Regulation*]; *supra* note 21 at 7, 11- 12; *supra* note 6 at xlvi.

[204] So as to prevent premature water production, well damage and loss of recovery, maximum rate of production is prescribed for natural gas that overlies water in the reservoir. See OGCA, *supra* note 67, ss. 37-39; *supra* note 21 at l; *supra* note 6 at 12-13, 26.

[205] This is to ensure that non-integrated, and especially smaller, independent producers have an equal opportunity to produce, transport, market or refine their allowable production. See OGCA, *supra* note 67, ss. 36, 48-54; *supra* note 6 at xlvi.

[206] *Supra* note 6 at xlix.

[207] Gas flaring usually occurs either "when a well is initially being tested for its productive capacity, when it is not economically feasible to gather the gas associated with oil production, or when an emergency arises, such as when a pipeline is leaking." See *supra* note 202 at p.1.65; World Bank, "Toward a World Free of Flares", online: World Bank <http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTOGMC/EXTGGFR/0,,contentMDK:21112929~pagePK:64168445~piPK:64168309~theSitePK:578069,00.html>. Note that while produced natural gas is also vented, it is not as common as when it is flared.

[208] The release of methane or a product of its incomplete combustion is a powerful greenhouse gas contributing to climate change. According to the World Bank, global gas flaring of solution gas adds about 350 million tons of carbon dioxide in annual emissions worldwide. It further posits that apart from the effect on climate change, gas flaring may have harmful effects on human health and ecosystem near the flaring sites. See Lynda Harrison, *supra* note 18; Mary Griffiths & Chris Severson-Baker, "Unconventional Gas: The Environmental Challenge of Coalbed Development in Alberta" (2006) at 10, online: the Pembina Institute <http://pubs.pembina.org/reports/CBM_Final_April2006D.pdf> [Griffiths & Severson-Baker].

make regulations for both purposes,[209] regulations to conserve natural gas will be the main focus of this part, since it is not possible, within the scope of this thesis, to examine regulations in respect of the latter.[210]

The OGCA[211] has several provisions to regulate the flaring of gas. Under the Act, the Board retains its power to restrict the amount of oil and gas that operators may produce. It may, as a waste prevention measure, require enhanced recovery operations in a pool or portions of the pool and require the introduction or injection into the pool of gas, air, water or other substance or a form of energy. It may also require that gas, when produced, be gathered and processed, or that gas be marketed or injected into an underground reservoir for storage or for any purpose.[212]

The Board recognizes that it is impossible to totally eliminate gas flaring. It therefore seeks to limit the amount of gas flared to quantities which experience indicates would not be economical to conserve having regard to the nature of the production and conservation system.[213] It also recognizes that the reduction of gas flaring is an on-going concern, and therefore adopts a concept of continuous improvement and consultation

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[209] OGCA, *supra* note 67, s.4 (a), (c), & (f); *supra* note 65, s.2 (c) & (d).

[210] Most of the regulations to prevent gas flaring are geared indirectly towards reducing its impact on the climate. In fact, the Board's collaboration with organizations like the Alberta Environment and the Clean Air Strategic Alliance (CASA) (CASA is a multi-stakeholder partnership, composed of representatives selected by industry, government and non-government organizations, which recommend strategies to assess and improve air quality in Alberta. See Clean Air Strategic Alliance online: <www.casahome.org>) is for this purpose. See for example, the Ambient Air Quality Objectives which were jointly introduced by the Board, Alberta Environment and CASA and which were established pursuant to s. 14 (1) of the *Environment Act*, *supra* note 198. See Griffiths & Severson-Baker, *supra* note 208 at 50.

[211] *Supra* note 67.

[212] See generally, the OGCA, *supra* note 67.

[213] It considers flaring to be necessary as the operators may not be able to conserve all solution gas. Thus an operator may be allowed to flare gas for purposes of testing the well to assess its capability and in order to determine the appropriate gathering and processing facility required to best handle the well's production; where it is not economically or technically practical to conserve such gas; or where there is an operational upset, such as equipment failure. Indeed, Mortensen agrees that flaring is permissible when it is not economical to gather the gas. See *supra* note 202 at 1.65; The Royal Bank of Canada, Global Energy and Minerals Group, T*he North American Natural Gas Industry: a Study prepared by* The Royal Bank of Canada, Global Energy and Minerals Group, (Np: The Royal Bank of Canada, 1985) at 117 [RBC].

with industry stakeholders to determine the need for additional requirements to facilitate a reduction in flaring.[214]

The flaring of gas from all types of oil and gas operations is regulated through regulations, interim directives, guides, information letters, bulletins, and legislative and extra-legislative incentives for gas flaring reduction. By far, the most comprehensive and effective regulatory tools are found in Directive 060: *Upstream Petroleum Flaring, Incinerating, and Venting* [Directive 060],[215] the *Climate Change and Emission Management Act* ("CCEMA")[216] and the legislative and extra-legislative incentives for gas flaring reduction. They will be respectively examined below.

3.4.1.1 Directive 060: Upstream Petroleum Flaring, Incinerating and Venting

Directive 060 sets out Alberta's requirements and expectations for the upstream petroleum industry by establishing requirements on solution gas management, well test flaring, gas battery flaring, gas plant flaring and pipeline emissions.[217] Some of the provisions of the Directive with respect to solution gas[218] flaring will be examined, as this accounts for about 70% of gas flared in Alberta and almost all the gas flared in Nigeria.

Conservation is defined in the Directive as the recovery of solution gas for sale, for use as fuel for production facilities, for other useful purposes (e.g., power generation), or for beneficial injection into an oil or gas pool (e.g., pressure maintenance, enhanced oil

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[214] See Directive 060: "Upstream Petroleum Flaring, Incinerating, and Venting", ERCB, D60-2006, s. 2, online: ERCB <http://www.ercb.ca/docs/documents/directives/Directive060.pdf> [Directive 060].
[215] *Ibid*., s. 8.6.
[216] S. A. 2003, C- 16.7.
[217] *Supra* note 214, s. 2-6.
[218] Solution gas forms part of the gas that is found in association with crude oil or bitumen. See *supra* note 202.

recovery).[219] Conservation opportunities are evaluated as economic or uneconomic based on the criteria listed in the Directive.[220]

The Board adopts a solution gas flaring/venting management framework and decision tree process. On this tree, where elimination is possible, the Directive requires operators to implement it. Where elimination is not feasible because of technical and economic factors, the Directive requires a reduction, which must meet flare performance requirements.[221] The Board will require conservation where it determines conservation to be economic, using the economic decision process outlined in the Directive.

The Board recognizes that solution gas conservation might be economic in some areas where operators coordinate their efforts to take advantage of combined gas volumes and economies of scale, for example, by clustering. It therefore expects operators to take clustering into account in the solution gas decision tree analysis and economic analysis.[222] The Board also recommends electricity generation as a viable alternative to flaring.[223]

Under the Directive, operators of oil, natural gas and bitumen production and processing facilities are required to give a monthly report of the amount of gas flared that is greater than or equal to 100 cubic metres ("m^3").[224] It further provides that operators

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[219] See *supra* note 214, s. 2. The Board does not consider the combustion of solution gas in incinerators an alternative to conservation. *Ibid*.

[220] *Ibid*. Perhaps in response to concerns about the utilization of economic consideration, the ERCB, in conjunction with CASA Flaring and Venting Project Team, Alberta Energy, Alberta Environment and other government agencies, is working on a number of recommendations for regulatory changes to address solution gas venting in crude bitumen production operations and other facilities. One of the issues currently under review is the economic test currently utilized to determine if oil facilities must conserve solution gas. See ERCB, News Release, "ERCB Report: Flaring and Venting of Solution Gas Increases 7.6% in 2008" (30 June 30 2009) [ERCB Report].

[221] Directive 060, *supra* note 214, s. 7.

[222] *Ibid*., s. 2.6.

[223] *Ibid*., s. 2.7.

[224] The measuring and reporting requirements of gas flared are in addition to that provided in Directive 017: "Measurement Requirements for Upstream Oil and Gas Operations" ERCB, D017-2009, online: ERCB

are to attain the reductions of routine solution gas flaring by restricting flare sizes as stipulated in the Directive.[225] Based on its mandate of continued improvement on routine solution gas flaring, the Board prescribes Alberta's solution gas flaring limit as 670 million cubic metres per year for all producers (which is 50% of the revised 1996 baseline of 1340 million m^3 per year).[226] Where these limits are exceeded in any particular year, the Board will impose reductions that will stipulate maximum solution gas flaring limits for operating sites.[227]

In areas where there are no existing conservation schemes, the Directive requires bitumen operators to pre-build a solution gas conservation line and also to implement economic solution gas conservation projects within six months after flow rate determination.[228] For crude oil operators, solution gas flaring during the test period must not extend beyond the time required to obtain data for economic evaluation and for sizing conservation equipment, and any flaring for testing, cleanup, and completions must not exceed a total of 72 hours. If, based on the testing, it is determined that the combined flaring and flaring volume will exceed 900 m^3 per day, the well must remain shut in until conservation is implemented.[229]

Existing oil wells are subject to more specific rules. Where the combined flaring and venting volume are greater than 900 m^3 per day per site and the decision tree process

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<http://www.ercb.ca/docs/documents/directives/Directive017.pdf>; Directive 007-1: "Allowables Handbook", ERCB, D007-1-2007, online: ERCB <http://www.ercb.ca/docs/documents/directives/directive007-1.pdf>; and the *Oil and Gas Conservation Regulations*, *supra* note 207, s. 10. A summary of flaring, incinerating, and venting emission details is compiled annually. The current one is ST60B-2009: "Upstream Petroleum Industry Flaring and Venting Report: Industry Performance for Year Ending December 31, 2008" (June 2009) online: ERCB <http://www.ercb.ca/docs/products/STs/st60b_current.pdf > [Flaring and Venting Report].

[225] Directive 060, *supra* note 214, s. 2.1.

[226] The Directive provides for a schedule of reducing routine solution gas flaring as measured against the 1996 baseline. See *ibid*.

[227] *Ibid*.

[228] *Ibid*., 2.4 (2).

[229] *Ibid*., 2.4 (1).

and economic evaluation result in a net present value of greater than CDN$50, 000, the gas must be conserved. Also, where a well's gas-oil-ratio is greater than 3000m^3/m^3, the well must be shut in until the gas is conserved.[230] The Board may still require economic evaluations for sites without conservation measures, which flare or vent combined volumes less than 900m^3 per day, if it is believed that conservation may be feasible.[231] Conservation facilities are also required to be designed for 95% conservation with a minimum operating level of 90%.[232]

Where it is not feasible for operators to eliminate flares, the Directive requires that they reduce the levels of volumes flared according to certain flare requirements. The Board recommends the use of enclosed flares and incinerators where this can better achieve efficient combustion.[233] The Directive also contain some recommendations on flare performance efficiency, which includes the design and operations of flare stacks and the use of best engineering practices in the design of flare systems.[234] Further, operators are expected to design and operate flares with a level of combustion efficiency that controls odour and visible smoke emissions.[235]

The Board has effectively utilized Directive 060 to achieve its mandate to effect the conservation of the province's natural gas and it has been very instrumental in the reduction of gas flaring reduction in the province. The Directive however needs to be revised in light of the emission intensity reduction target in the CCEMA.[236]

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[230] *Ibid*., 2.5.
[231] *Ibid*., 2.5(3).
[232] *Ibid*., 2.5(4).
[233] The Directive set out specific mandatory combustion efficiency levels. See *ibid*., s. 7.1.
[234] *Ibid*.
[235] *Ibid*.
[236] *Supra* note 216.

3.4.1.2 Climate Change and Emission Management Act ("CCEMA")

The CCEMA provides for an intensity-based target of reducing Alberta's emissions to 50% of 1990 levels by 2020.[237] The Act requires facilities with greenhouse gas ("GHG")[238] emissions above certain thresholds to report their emissions. It also grants Alberta's cabinet the authority to regulate emissions and offsets.[239] In addition to simply reducing emissions to meet its target, a facility can comply by offsetting its emissions in accordance with Alberta Environment's offset project guidelines.[240] Those facilities failing to meet emissions intensity reduction targets can either pay $15 per tonne of carbon dioxide (CO_2) into the Climate Change and Emission Management Fund ("the Fund") or buy emission performance credits from facilities that have reduced their emissions below required levels.[241]

In January 2008, the Alberta government introduced the Alberta's Climate Change Strategy (the "Strategy")[242] and amended the CCEMA. The Strategy calls for the intensity targets set in the CCEMA to be reached by 2010; for GHG emissions to be stabilized by 2020; and for an absolute GHG emission reduction of 14% below 2005

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[237] *Ibid*., s. 3(1).

[238] Carbon dioxide and methane emitted during the burning of natural gas are major green house gases. See David R. Hodas, "Energy, Climate Change and Sustainable Development" in Adrian J. Bradbrook & Richard L. Ottinger, eds., *Energy Law and Sustainable Development* (Gland: International Union for Conservation of Nature and Natural Resources, 2003) at 12-13 [Bradbrook & Ottinger].

[239] The Specified Gas Emitters Regulation, Alta. Reg. 254/2007 ("Emitters Regulation") has been promulgated under the Act. It requires facilities with annual GHG emissions at or above 100,000 tonnes to apply for a baseline emissions intensity). The Regulation distinguishes between new and established facilities, defining the former to be a facility that began operations in 2000 or later. New facilities need not reduce their emissions within their first three years of operation. Established facilities, as of 2008, must reduce their annual emissions intensity by twelve percent.

[240] *Supra* note 216, s. 5.

[241] *Ibid*. See also ADE, "Launching Alberta's Energy Future, Provincial Energy Strategy", online: ADE <http://www.energy.alberta.ca/Initiatives/1510.asp>.

[242] See Alberta Environment (AENV), "2008 Climate Change Strategy: Responsibility / Leadership / Action", (January 2008) online: <http://environment.gov.ab.ca/info/library/7894.pdf>.

levels by 2050. The Strategy takes action on three fronts: energy efficiency and conservation; carbon capture and storage; and sustainable energy production.[243]

Carbon capture and storage (CCS) is one of a number of potential technological options to reduce anthropogenic emissions of CO_2.[244] It may help states meet the stabilization objective of the *United Nations Framework Convention on Climate Change*[245] and the quantified emission limitations of the *Kyoto Protocol to the United Nations Framework Convention on Climate Change* ("Kyoto Protocol").[246] CCS refers to the capture of the CO_2 produced by various industrial processes and the storage/disposal of that CO_2 in a storage/disposal reservoir where it will remain for a long period of time without significant atmospheric leakage. The captured carbon can then be used for enhanced oil recovery.[247] Carbon capture is most likely to occur at large-point sources. These sources include large fossil fuel or biomass energy facilities, major CO_2- emitting industries such as natural gas production facilities (especially where the gas stream includes a high CO_2 content).[248]

In 2008, the Alberta Government announced that it will contribute $2 billion to encourage the development of CCS in the province.[249] Four projects proponents have

[243] *Ibid*.
[244] Nigel Bankes, Jenette Poschwatta & Mitchell E. Shier, "The Legal Framework for Carbon Capture and Storage in Alberta" (2007-2008) 45 Alta. L. Rev. 585 at 586.
[245] 9 May 1992, 1771 U.N.T.S. 107, 31 I.L.M. 849 (entered into force 21 March 1994).
[246] 11 December 1997, UN Doc. FCCC/CP/1997/7/Add.1, 37 I.L.M. 22 (entered into force 16 February 2005).
[247] *Supra* note 244 at 590.
[248] *Ibid*.
[249] Alberta Carbon Capture and Storage Development Council (ACCSDC), "Accelerating Carbon Capture and Storage in Alberta", online: ACCSDC http://www.energy.alberta.ca/Org/pdfs/CCSInterimRept.pdf> at 11.

since signed Letters of Intent with the government for funding from the $2B CCS fund to develop technology to capture, transport, store, and use the captured CO_2.[250]

Since April 2008, when the Fund was lunched, the options for compliance have resulted in approximately 2.6 million tonnes of actual reductions through operational changes and practices - including better use and re-use of energy - and investing in verified offsets created by other Alberta projects. Companies also chose to pay approximately $40 million into the Fund. The monies in the Fund will be invested in projects and technology to reduce greenhouse gas emissions in Alberta.[251]

3.4.1.3 Legislative and Extra-Legislative Incentives

The province has developed incentives to encourage natural gas conservation. They include the *Otherwise Flared Solution Gas Royalty Waiver Program* introduced by the Department of Energy.[252] The program, which now has statutory backing,[253] contains specific royalty incentives to encourage natural gas conservation. By virtue of this program, the Department of Energy waives royalty on uneconomic solution gas and its associated by-products when used in a manner that would normally attract the payment of royalty. The waiver lasts for ten years from the first day of the month in which the application was received.[254]

Another incentive is the Injection Credit provisions of the Natural Gas Royalty Regulations.[255] Under this provision, if natural gas or a gas product is injected during a

[250] ADE, "Carbon Capture and Storage" online: ADE <http://www.energy.alberta.ca/Initiatives/1438.asp>.
[251] AENV, "Climate Change", online: AENV <http://www.environment.alberta.ca/1319.html>.
[252] See ADE, Information Letter, 1999-19, "Otherwise Flared Solution Gas Royalty Waiver Program", (11 June 1999), online: ADE < http://inform.energy.gov.ab.ca/Documents/Published/IL-1999-19.PDF >.
[253] See *supra* note 107, s.14.
[254]See *supra* note 252.
[255] See *supra* note 107, s. 17.

production month into a pool through a gas injection facility for the account of or for the benefit of an operator, the Minister is directed to establish an injection credit for that production month for that operator. An injection credit is then applied to the operator's royalty account.[256]

3.5 Enforcement Mechanism

The Board is vested with several enforcement powers under various statutes and regulations.[257] The ultimate goal of the Board's enforcement and compliance process is to ensure energy activity within the province is conducted in a manner that protects public safety, minimizes environmental impact, preserves equity, and provides effective resource conservation.[258] These processes are subject to internal audit, reporting, and accountability processes. Also, the Board's internal governance systems establish clear roles and responsibilities to ensure that policies are applied fairly and consistently.[259]

Under the Board's enforcement process, as provided in its Directive 019, *Energy Resources Conservation Board Compliance Assurance – Enforcement* [Directive 019],[260] the severity of the non-compliance determines the enforcement action. This severity is assessed on a Risk Matrix indicated as either low or high.[261] The Board will escalate

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[256] See *ibid*.
[257] See for example, the OGCA, *supra* note 67, s. 7 which allows the Board, with the approval of the Lieutenant Governor in council, to make any just and reasonable orders and directions which might not have been specifically authorized in order to effect the purposes of the Act.
[258] See ERCB, online: ERCB <http://www.ercb.ca/portal/server.pt?open=512&objID=255&PageID=0&cached=true&mode=2>.
[259] ERCB, Directive 019, "Energy Resources Conservation Board Compliance Assurance – Enforcement", (February 20, 2007) online: ERCB <http://www.ercb.ca/docs/documents/directives/Directive019.pdf>.
[260] *Ibid.*
[261] The low or high risk rating is based on health and safety, environmental impact, conservation and stakeholder confidence in the regulatory process. See *ibid*., s. 3.

enforcement actions as necessary in the event that initial enforcement does not result in compliance or when an operator has been identified as persistently non-compliant.[262]

Where there has been initial low risk non-compliance, the Board may instruct the licensee to take corrective actions at the site and ensure compliance at all similar facilities. Failure to take the required steps will result in the operator being identified as persistently non-compliant. This status may result in the cancellation and or suspension of permits, licenses, or approvals; self or third party audit or inspection; the payment of non-compliance fee; issuance of an Order: miscellaneous, closure or abandonment;[263] and "Refer" status: focused or global.[264]

When there has been initial high risk non-compliance, one or more of the enforcement processes employed in the case of persistent low risk non-compliance will be applied. Further failure to comply will result in the escalation of the non-compliance to persistent and the Board will request that the licensee fully or partially suspend operations to correct deficiencies and alleviate impact or potential impact. Where the licensee does not comply with this requirement, it will be subjected to escalated enforcement action. The Board may also take corrective actions itself and charge the

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[262] *Ibid*., s.4.

[263] These Orders are all legal document that orders the carrying out of a specific action. A miscellaneous formally orders a specific action other than closure or abandonment, e.g., cleanup of a spill; a closure order formally orders the closure and suspension of a property and prevents any further operations from occurring without the Board's consent until the order is rescinded. While an abandonment order formally orders a property to be properly abandoned by the responsible parties. See ERCB, "Compliance Performance and Enforcement Information", online: ERCB <http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_318_255_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/industry_zone/compliance_and_enforcement/compliance_information/>; *ibid*., s. 7.

[264] A Refer status is an enforcement status that describes a licensee that is unable or unwilling to comply with the Board's directions. This status results in a more rigorous review of a licensee's pending and future applications having regard for the compliance status of the licensee. This status is removed when compliance is achieved. Refer status is regarded as focused, when it is in respect of a specific activity or operation and global when it refers to all of the licensee's activities or operations. *See supra* note 259 at 9.

costs to the licensee as a means of ensuring compliance.[265] As a last resort, the Board may refer a matter to prosecution when it believes a licensee has acted with demonstrated disregard.[266]

Directive 060 also provides compliance and enforcement requirements for gas flaring. It employs a categorization similar to the enforcement process outlined in Directive 019.[267] Since the coming into force of these Directives, there have been no major events requiring the Board's enforcement. Industry compliance with the provision of the Directives has been voluntary and the companies have met the targets set by the Board, making it unnecessary to impose any compulsory regulatory enforcement. This level of compliance can be attributed to the fact that the Board developed the provisions of the Directives through a consensus based process with operators in the oil and gas industry.[268]

The hallmark of the Board's enforcement mechanism is the emphasis on the use of informal, voluntary arrangements between the Board's staff and the licensees in resolving disputes and achieving compliance with the regulations. Prosecution is rarely resorted to; where it is used, it is always as a last resort. The Board believe that its approach is quick, inexpensive and fair in attaining its conservation objectives and preferable to the unwieldy and formal mechanism of prosecution.[269] It is submitted that this approach, rather than an adversarial approach, is more in touch with Alberta's free market economy and also more practical. Mediation and alternative dispute resolution

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[265] *Ibid*., s. 4.2.
[266] *Ibid*.
[267] *Supra* note 214 at s. 12.
[268] See Ibironke T. Odumosu, "Transferring Alberta's Gas Flaring Reduction Regulatory Framework to Nigeria: Potentials and Limitations" (2007) 44 Alta. L. Rev. 863 at 883.
[269] *Supra* note 190 at 119.

measures may also play a vital role here. Informal bargaining and negotiation promotes an atmosphere of understanding and cooperation. This approach will encourage operators to voluntarily comply, since they are aware that the board can resort to its prosecutorial power when they so fail.[270]

The Board's enforcement process has translated to reduced volumes of flared gas in the province. Solution gas flaring has been reduced by 77% since 1996 and solution gas venting has been reduced by 41% since 2000.[271] The Board indicates that in 2008, the upstream oil and gas industry conserved 95.1% of all solution gas produced in Alberta for use or sale, rather than flaring and venting it.[272] Flaring of solution gas dropped by 5.8%. In total, 306 million m^3 of solution gas were flared in 2008 compared to 325 million in 2007. Venting of solution gas increased 20.1% in 2008, in total, 417 million cubic metres of solution gas were vented in 2008 compared to 347 million m^3 in 2007. The increase is primarily attributed to higher bitumen well drilling. The new bitumen wells produce small volumes of solution gas that are insufficient to keep a flare stack lit, so small that they do not meet the Board's test for conservation.[273] The increase in solution gas venting is of particular concern, as conservation is not effective if flaring decreases while venting increases.

3.6 Assessment

Although conservation is an ongoing enterprise, Alberta has been able to conserve a very high percentage of its natural gas. The World Bank regards Alberta as being in the

[270] According to Breen, *supra* note 6 at 532, the overall result of Alberta's uncontestable legal authority is a field environment characterized by general cooperation and compliance; and where the Board field inspectors called attention to infractions, industry is customarily quick to address the problem. See also *ibid*.
[271] Flaring and Venting Report, *supra* note 224 at iv.
[272] See ERCB Report, *supra* note 220.
[273] *Ibid*., Flaring and Venting Report, *supra* note 224.

forefront of natural gas regulations world-wide.[274] This achievement was through the enactment of specific legislation on natural gas conservation and the establishment of an agency with a specific mandate to ensure conservation. The Board has achieved this mandate because of its financial and regulatory independence, highly developed technical know-how, expert human resources, and an effective mechanism to enforce the provisions of its enabling Statutes. Alberta has therefore come a long way from the initial waste that characterized the development of its natural gas resource.

Alberta is however facing future challenges that will also be faced by Nigeria. The finite nature of natural gas means that as long as it is developed, it will become exhausted. The rate of natural gas development in Alberta has led to its rapid exhaustion. New pools are smaller, and new wells drilled today are exhibiting lower initial production rates and steeper decline rates. CBM production is forecast to supplement the supply of conventional gas in the province but not to replace the decline in conventional gas production.[275] There is thus a need to develop natural gas in an orderly fashion in the sense of extending the life of the resource to allow for an orderly transition to alternative fuels.

Another challenge is the negative impact of natural gas development on the environment. It is clear from the above that the Board has focused more on the waste prevention aspect of conservation and not the environmental aspect.[276] In carrying out

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[274] Lynda Harrison, *supra* note 18.

[275] See ERCB, "Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018" online: ERCB <http://www.ercb.ca/docs/products/STs/st98-2009.pdf> at 5.1. The Board also forecast that conventional gas production in the province will decline by 6.0 per cent in 2009 and an average of 4.0 per cent per year thereafter. *Ibid*.

[276] See Michael M. Wenig & Michael C. Moore, "Searching for Meaning in Energy Resource Conservation" (2007) 99 Resources 1.

their conservation mandate, it is imperative that conservation bodies, like the Board, seriously consider the impact of natural gas development on the environment.

4 UTILIZATION OF NATURAL GAS

The whole purpose of natural gas conservation is to provide for its present and future utilization. In Alberta, there is a ready market and an extensive pipeline infrastructure which provides an avenue for putting to economic use natural gas which would otherwise have been flared. There are two major ways in which natural gas is utilized domestically by residential, commercial, and industrial consumers and by export to regional and international markets.

4.1 Domestic Utilization

Domestically, there is an extensive natural gas market supplied by a large network of pipelines.[277] The industrial sector, which includes the electricity, petrochemical and oil-sands industry, is the main consumer of the province's natural gas.[278] The second

[277] Pipeline transportation is the predominant mode of transporting natural gas in Alberta. The province has one of the most extensively developed natural gas pipeline system, with over 110,000 km of domestic natural gas pipelines. The *Pipeline Act*, R.S.A. 2000, c. P-15, makes provisions for the regulation of these systems. The Act applies to all pipelines within the province except those situated within refinery or other plant, and those subject to the jurisdiction of the National Energy Board. See Alberta Agriculture and Rural Development, "Rural Gas Program" Alberta Agriculture and Rural Development, online: <http://www1.agric.gov.ab.ca/general/progserv.nsf/all/pgmsrv13>.

[278] The industrial sector uses just over 75% of the natural gas that is produced in Alberta. It is used in the refining of crude oil and the production of oil sands, generation of electricity, and as a feedstock for petrochemical products. The oil sands industry is presently the largest user in this category. Oil sands facilities use large amounts of natural gas for steam production, electrical cogeneration and diluent. See *supra* notes 7 & 8; *supra* note 21 at 21; Rylska, Nataliya L. & Grarbeiel, Joan E., "Alberta Benefits: Northern Gas Pipeline Development" (Edmonton: Western Centre for Economic Research, 2003) at 6. See also Heritage Community Foundation "Alberta's Resource Inventory", online: ECF <http://www.abheritage.ca/abresources/inventory/resources_hydro_gas.html>.

groups of consumer are the residential[279] and commercial[280] consumers, who use natural gas for heating and cooking.[281] Both groups also utilize natural gas, in the form of compressed natural gas, as a transportation fuel.[282]

In Alberta, natural gas distribution and transmission systems are fully regulated primarily under the provisions of the *Gas Utilities Act*,[283] *Gas Distribution Act*,[284] and the *Pipeline Act*.[285] Investor-owned distribution companies are regulated by the Alberta Utilities Commission ("The Commission"),[286] while municipally owned systems are regulated by their municipal councils, and natural gas co-operatives are regulated by their elected board members. The Commission further approves the construction of

[279] Natural gas is one of the cheapest forms of energy available to residential consumers in Alberta. It equally has the most varied uses. It uses include space and water heating of homes and domestic cooking. See ADE, *supra* note 7.

[280] Commercial users are those that use natural gas at their commercial sites. These include schools, municipalities, government, and hospitals. Commercial uses of natural gas are closely associated with residential uses. For instance, restaurants in Alberta use natural gas for their cooking needs, while the government, at the provincial and municipal levels, employs natural gas in heating and cooling public spaces. Large commercial enterprises are also beginning to use natural gas for on-site electricity generation as an economical alternative to purchasing electricity off-site. See *ibid*.

[281] See ADE, "About Natural Gas", online: ADE <http://www.energy.gov.ab.ca/NaturalGas/555.asp>.

[282] In 2005, more than 4,500 natural gas powered vehicles were registered in Alberta. These vehicles are serviced by 12 public re-fuelling stations and other privately owned re-fuelling stations. In Canada as a whole, there are around 25, 000 natural gas vehicles currently in operation. These vehicles are supported by 120 public retail and 80 on-site re-fuelling stations. Another 1700 vehicles refuelling stations have been installed in test markets for both residential and commercial applications. In addition, there are over 120 natural gas-fuelled public transit buses in use and another 200 on the order. See Alberta Ministry of Transportation, "Natural Gas Vehicles in Alberta", online: AMT <http://www.transportation.alberta.ca/Content/docType57/Production/NGVBrief.pdf>; Michelle Heath *et al*., *Alternative Transportation Fuels in Canada: Prospects and Policies* (Calgary: Canadian Energy Research Institute, 1996) at 19.

[283] R.S.A. 2000, c. G-5.

[284] R.S.A. 2000, c. G-3.

[285] *Supra* note 277.

[286] The Commission is an independent, quasi-judicial agency of the Government of Alberta. Its mission is to ensure that the delivery of Alberta's utility services take place in a manner that is fair, responsible, and in the public interest. The Commission regulates investor-owned natural gas, electric, and water utilities and certain municipally owned electric utilities to ensure that customers receive safe and reliable service at just and reasonable rates. See generally, the AUCA, *supra* note 66.

transmission pipelines in Alberta and the rates, tolls and other charges, and terms and conditions of service of such transmission pipelines.[287]

Natural gas is transported from the "wellhead" or natural gas processing plant through a provincial-wide natural gas pipeline network of over 23,500 km called the Alberta system. The Alberta intra-provincial system acts much like a highway, moving large quantities of natural gas through a high-pressure, high volume pipeline. From the Alberta system, natural gas is transferred either into an export pipeline at the BC, Saskatchewan, or Montana border, or to a low-pressure local distribution pipeline system, owned by gas utility companies. The distribution system delivers the gas directly to domestic end-user, acting more like a smaller and more local road system.[288]

This in-province transmission system includes the concepts of *common purchaser, common processor and common carrier*.[289] These concepts were conceived as a means of affording each owner a chance at producing. They avoid monopolization of production through creation of systems that could deny access to other producers. Also, through the joint use of facilities, costs are reduced for the mutual benefits of consumers, producers and distributors.

Domestic consumers purchase natural gas at a regulated rate from regulated retailers, under contracted terms from competitive retailers, or directly from the producers, in the case of industrial consumers.[290] Whatever the rate may be, Albertans

[287] See *supra* note 283. See also Alberta Utilities Commission, "Role in Natural Gas Market", online: AUC <http://www.auc.ab.ca/about-the-auc/who-we-regulate/Pages/RoleinNaturalGasMarkets.aspx>[AUC Role].
[288] See also TransCanada, "TransCanada's Alberta System: A Profile", online: TransCanada <http://www.transcanada.com/gas_transmission/alberta.html>.
[289] See OGCA, *supra* note 67, part 9.
[290] Only the regulated retailers are regulated by the Commission, as it has no jurisdiction over competitive retailers. See AUC Role, *supra* note 287.

still enjoy the lowest price for natural gas in Canada.[291] For instance, 37% of the total marketable natural gas produced in Alberta in 2008 was utilized domestically.[292]

The *Gas Resources Preservation Act* ("GRPA") provides that a removal permit is required to export gas from the province.[293] The Board is prohibited from issuing a removal permit unless it is of the opinion that it is in the public interest to do so, having regard to the present and future needs of persons within Alberta, the established reserves and the trends in growth and discovery of reserves of gas in Alberta and any other matter it considers relevant.[294] If the Board finds that it is in the public interest to grant the permit, it may do so, with the approval of the Lieutenant Governor or Minister of Energy.[295] The consideration of public interest ensures that the availability of natural gas is assured to Albertans.

The GRPA may be impacted by the provisions of the *North America Free Trade Agreement* (NAFTA) and rules of the World Trade Organization (WTO) on trade and export restriction.[296] In order to assert full control over its natural resources, Alberta has always supported free trade. The province gave strong support to the federal proposal for

[291] See Annual Report, *supra* note 102 at 40.
[292] *Ibid*., at 20.
[293] R.S.A. 2000, c. G-4.
[294] *Ibid*., at s. 8. See also Crommelin, *supra* note 31 at 191; *supra* note 202 at 1.64; Robert C. Muir, "Utilization of Alberta's Gas" (1975) xiii, Alta. L.Rev. at 68.
[295] The permit may be subject to prescribed terms and conditions, such as the maximum annual quantities of gas that may be removed during the interval(s) set out in the permit, the maximum daily quantities of gas that may be removed and the period for which the permit is operative. See *supra* note 293, ss. 2-7.
[296] Canada is a member of the WTO and a signatory to the NAFTA. As such, the Federal and Provincial governments are bound by the rules of the WTO and the Agreement. See Foreign Affairs and International Trade Canada ("FAITC"), online: FAITC <http://www.international.gc.ca/trade-agreements-accords-commerciaux/agr-acc/nafta-alena/texte/index.aspx>; World Trade Organization, online: <http://www.wto.org/index.htm>.

the NAFTA.[297] This perhaps explains why the GRPA has not been attacked for violating the relevant provisions of the NAFTA.[298]

In Alberta, gas storage is very common and the capacity is second only to that of Ontario. Through gas storage, the availability of natural gas is also assured to Albertans all year long. It is an unregulated system that allows gas to be added to the inventory during the summer months, when gas demand is seasonally low, and withdrawn during the cold winter months, when gas demand is seasonally high. This system improves the pipeline load factor, consequently reducing the cost of gas to distribution companies and natural gas consumers.[299] Future gas storage development and planning may be impacted by the requirements of ALSA.[300]

4.2 Export

Alberta produces more natural gas than it consumes, which allows over three quarter of the natural gas it produces to be available for export to regional markets, like other Canadian provinces and the United States.[301] In 2008, Alberta exported 24% of its total natural gas production to other Canadian provinces and 39% to the United States.[302]

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[297] Susan Blackman *et al.*, "The Evolution of Federal/Provincial Relations in Natural Resources Management" (1994) 32 Alta. L. Rev. 511 at 524.
[298] See NAFTA, *supra* note 296, Chapter 6- Energy and Basic Petrochemical.
[299] RBC, *supra* note 213 at 109.
[300] *Supra* note 192.
[301] All of Alberta's international natural gas exports are destined for the United States natural gas market. See Annual Report, *supra* note 102 at 20.
[302] See *ibid*.

One of the largest natural gas hubs in North America is located in Alberta.[303] Through its large networks of pipelines, gas is gathered from inside Alberta and transported through numerous export transmission lines to major exporting systems which connect Alberta with markets across Canada and the United States.[304] The TransCanada Mainline, which is over 14,101 km in length, is Canada's main inter-provincial and international pipeline, and one of the world's longest gas pipelines. It extends from the Alberta/Saskatchewan border east to the Québec/Vermont border and connects with other natural gas pipelines in Canada and the United States.[305] The Hub and the extensive transmission system facilitate the export of Alberta's natural gas to inter-provincial and international markets, thereby aiding its utilization.

NAFTA has played a huge role in the export of Alberta's gas to the United States, but it has some significant implications for conservation. An increase in international economic activity would certainly increase the rate of depletion of limited natural gas

[303] The storage capacity in the hub is quite large. It is owned by Alberta Energy Company (AECO) (now part of Encana) and located in Suffield in south east Alberta. The Hub, which is considered as the most important natural gas hub in North America, is further reflected in the fact that the Alberta gas-trading price (the AECO "C" spot price) is one of North America's leading price setting benchmarks. See NIT: The Engine of Alberta's Natural Gas Hub, online <http://www.transcanada.com/Customer_Express/Update/holiday_2005/article_3.html>.

[304] See Natural Gas, *supra* note 8.

[305] See TransCanada, "TransCanada Mainline System: A Profile" online: TransCanada <http://www.transcanada.com/gas_transmission/mainline.html>. Other pipelines include the Foothills Pipelines and the Alliance Pipeline. The Foothills pipeline is a 1,241 km natural gas transmission system which carries natural gas for export from central Alberta to the U.S. border to serve markets in the U.S. Midwest, Pacific Northwest, California and Nevada. See TransCanada, "TransCanada's Foothills System: A Profile" online: TransCanada < http://www.transcanada.com/Foothills/system_overview/>. The Alliance pipeline extends from Northeast British Columbia, with receipt points in Alberta, directly into the U.S. Midwest. See Alliance Pipeline, "Our Pipeline, Our System" online: Alliance Pipeline <http://www.alliance-pipeline.com/inside.jsp?cid1=2&cid2=25&cid3=0>. See also *supra* note 202 at 2.24-2.26.

resources.[306] Also, implementation of some environmental policies might prove difficult, as such policies might be perceived as creating obstacle to trade.[307]

Assessment

There is no doubt that the province has an effective system in place for the utilization of its natural gas. Even as it strives to ensure that natural gas is available for domestic consumption and for export purposes, it is quite apparent that its main priority is the protection of domestic consumers in terms of price and availability of the product.

5 SUMMARY

This part highlighted the methods utilized by Alberta in developing its natural gas resource. The examination, which was conducted using three core regimes for effective development, confirmed that the province has made the most use of its natural gas resources and continues to remain a global leader in the development of natural gas. This underscores the choice of Alberta's method as an example for Nigeria. In the next part, Nigeria's framework for developing its natural gas will be examined to determine where Alberta's method can best be applied.

[306] Raymond Walker, "The Effect of NAFTA on Environmental Regulations in the United States, Canada, and Mexico", (2000) 6 NAFTA Law & Bus. Rev. Am. 85 at 86.
[307] See Bradly J. Condon, "NAFTA and the Environment: A Trade-Friendly Approach", (1993-1994) 14 Nw. J. Int'l L. & Bus. 528 at 532. See also *In the Matter of Canada's Landing Requirement for Pacific Coast Salmon and Herring*, 1989 WL 250302 (Oct. 16, 1989).

PART 3

NIGERIA'S LEGAL FRAMEWORK FOR NATURAL GAS DEVELOPMENT

1 INTRODUCTION

This part is divided into three main sections. The first section will examine the regime for the acquisition of natural gas in Nigeria. In this section, the mineral ownership system in the country and the relevant regulatory authority will be reviewed. The mode of acquiring natural gas rights is also examined. The next section will consider the regime for the conservation of natural gas in the country. The last section will examine the natural gas utilization regime.

As at the time of writing, Nigeria is still trying to find a way to develop its huge natural gas reserve, which consists of an equal proportion of associated and non-associated gas.[1] The examination conducted in this part will assist in achieving the goal of suggesting an effective method for the exploitation of Nigeria's natural gas. The history and development of natural gas in the country will first be examined, as this is relevant to an understanding of why natural gas is not being effectively developed in the country.

[1] Most of the proven reserves are found as associated gas in the Niger Delta basin, while the majority of the non-associated gas has been discovered off-shore Nigeria in relatively simple geological structures adjoining the country's coastal Niger River Delta and in the offshore blocks. See George Nnona, "New Policy Regime for Gas in Nigeria: A Perspective on Tax and Related Incentives" (2003) 21 J. Energy, Nat'l Res. L., 285 at 286 [Nnona]; See Michael J. Economides, A.O. Fasina & B. Oloyede, "Nigeria Natural Gas: A Transition from Waste to Resource" (2004) 7:1 World Energy, online: World Energy < http://www.worldenergysource.com/articles/text/economides_WE_v7n1.cfm > [Economides].

1.1 History and Development of Natural Gas in Nigeria

With an area of 924 sq. kilometres and an estimated population of 151.54 million inhabitants, Nigeria is the most populous country in Africa.[2] It is a country with significant poverty, considerable governance challenges and aggravated ethnic tension. The root cause of these challenges and tensions has been said to be a consequence of its diverse ethnic social make-up, as well as the nature of federal and state government relations.[3]

Just as in Alberta, the discovery of natural gas in Nigeria was incidental to the discovery of crude oil.[4] The first commercial discovery of oil was made by Shell Petroleum Development Company ("Shell") in 1956, at a location near Oloibiri in the Niger Delta[5] (present day Bayelsa State), with production starting at 5,100 barrels per day in 1958. This discovery, and subsequent commercial production at other locations in the Niger Delta[6] by six other multinational petroleum production and exploration companies,[7] ushered Nigeria into the international group of major petroleum producers and exporters.[8]

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[2] See Nigerian National Petroleum Corporation, "Nigeria Profile", online: NNPC <http://www.nnpcgroup.com/nigeria-profile>; Organisation of the Petroleum Exporting Countries, "Annual Statistical Bulletin 2008: Nigeria Facts and Figure", online: OPEC <http://www.opec.org/aboutus/member%20countries/nigeria.htm> [OPEC, ASB 2008].

[3] Ahmad Khan Sarah, *Nigeria: the Political Economy of Oil* (Oxford: Oxford University Press 1994) at 6.

[4] The incidental discovery of natural gas enabled it to be regarded as a nuisance and treated as a waste. See Yinka Omorogbe, "Law and Investor Protection in the Nigerian Natural gas Industry" (1996) 14 J. Energy Nat Resources L. 179 at 181[Omorogbe, Law and Investor Protection].

[5] Seismic records have overwhelmingly testified to the level of proven petroleum reserves in the Niger Delta, making it the focal point for exploration and production development in Nigeria. Thus all major production to date has occurred in the Niger Delta Basin. Operating conditions in this basin has however been quite challenging as a result of the difficult onshore terrain, perennial incidents of community instability, attacks on installations, and sabotage of oil and gas related facilities. See Adedolapo Akinrele, *Nigeria Oil and Gas Law* (N.p: Oil, Gas & Energy Law Intelligence, 2005) at 16.

[6] These were in Bomu, Ebubu, Imo River, and Korokoro. See L. H. Schatzl, *Petroleum In Nigeria*, (Oxford: Nigerian Institute for Social and Economic Research, 1969) at 4 [Schatzl].

[7] These companies were: Exxon, ESSO, Mobil, Standard Oil Company of Califonia (Socal), gulf Oil Corporation (now Chevron in Nigeria), and British Petroleum. See Lawrence A. Atsegbua, *Nigerian*

The lack of interest in natural gas production has resulted in commercial reserves of natural gas being shut in.[9] According to Economides *et al*, if the theory that huge natural gas reserves exist in deepwater fields holds true, then there are yet to be discovered natural gas in Nigeria's huge deepwater region.[10] The non-production of existing reserves and non-exploration of potential reserves, have left the Nigerian natural gas industry seriously under-developed.

But for a few statutes that deal specifically with natural gas, most legislation enacted to date deals with oil production.[11] It is contended that Nigeria has to promote intelligent legislation for the orderly exploitation of its natural gas so as to ensure its effective development and the accrual of deserved benefits to the country.

Although various measures have been taken to develop the natural gas industry,[12] the government has recognized that these measures are grossly inadequate and is adopting more measures to remedy the situation. According to the former Group Managing Director of the Nigerian National Petroleum Corporation, the country has set a

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Petroleum Law: The Acquisition of Oil Rights in Nigeria (Benin City: New Era Publications, 1993) at 9 [Atsegbua].

[8] See Scott R. Pearson, *Petroleum in Nigeria Economy* (California: Standard University Press, 1970) at 15.

[9] Other prospective natural gas basins, like the Benin, Anambra, Chad and Bida Basins, and the Benue Trough, are yet to be fully explored. See Economides, *supra* note 1.

[10] *Ibid*.

[11] Nigeria's oil and gas legislation were primarily drafted to regulate crude oil exploitation and production, without specific provisions for natural gas; as a result, there is only very little legislation dealing with the subject and the development of the natural gas industry is quite recent. According to Martin Olisa, these legislation are scanty, generalised, and appear to be as incidental as associated gas is in the course of searching for crude oil. See Martin M. Olisa, *Nigerian Petroleum Law and Practice*, 2nd ed. (1997: Jonia Ventures Ltd., Lagos) at 276.

[12] The Oso Condensate Project, situated offshore in Akwa Ibom State, the Nigerian LNG project located in Bonny, Rivers State, the Escravos Gas Project at Ugborodo in Delta State and the West Africa Gas Pipeline Project (WAGP) are some of the major projects in this area. Even before the commencement of the above gas projects, the Afam, Sapele, Oben, and egbin power stations had started utilizing gas to generate electricity. Also, a number of industrial layouts and companies, like the Aba Industrial Estate, Ajaokuta Steel Plant, the National Fertilizer Company of Nigeria Ltd., delta Steel Company, and the Aluminum Smelting Company of Nigeria Ltd., relied on gas supplied to them by the Nigerian National Petroleum Corporation (NNPC) through the Nigerian Gas Company Ltd. to manufacture its products. The country has also established fiscal incentives for the encouragement of the development and utilization of natural gas, through internal commercial utilization and well as export. See generally, *ibid.* at 276-284.

principal target to stem gas wastage and re-orient the economy from a predominantly oil economy, to an oil and gas economy where natural gas would rank in equal importance, if not surpass, oil in revenue earnings.[13]

Also during the last cabinet formation, the President of Nigeria, Umaru Musa Yar'Adua, appointed a Minister of Petroleum Resources and three junior Ministers for power, gas and petroleum (crude oil) to assist him. This was in order to streamline the Federal Ministry of Petroleum Resources and create specific portfolios for each energy resource.[14] Although these are commendable steps, industry stakeholders are less than enthusiastic. To them, it is just another way of creating a bureaucratic bottleneck that will pave way for further corruption.[15] Also, it is not clear if the government, in taking these measures or making these appointments, has fully considered the environmental impact of oil and gas development. The regime for the acquisition of natural gas interest will now be examined.

2 ACQUISITION OF NATURAL GAS INTERESTS

This section will examine the ownership of mineral rights in the country with particular reference to natural gas, the relevant regulatory authority, and the modes of acquiring natural gas rights.

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[13] F.M. Kupolokun, (Former Group Managing Director of NNPC), "Nigeria and the Future Gas Market" (A lecture presented at the Baker Institute of Energy Forum, Houston, U.S.A., May 2, 2006) online: NNPC <http://www.nnpcgroup.com/news/speech2.htm>.

[14] See, "Nigeria's President Names Cabinet" *BBC News*, (26 December 2007), online: BBC News <http://news.bbc.co.uk/2/hi/africa/6914380.stm> [BBC]; Uchenna Izundu, "Lukman Appointed Nigeria's New Petroleum Minister" (5 January 2009) 107:1 the Oil & Gas Journal, online: <http://www.ogj.com/articles/article_display.cfm?ARTICLE_ID=348365> [Izundu, Nigeria's New Petroleum Minister].

[15] Years of political interference, embezzlement, bureaucracy and incompetence has earned the Nigerian national petroleum company a reputation as a mere milch cow for a succession of corrupt Nigerian regimes raiding its resources on a massive scale. See *supra* note 3 at 26; *supra* note 16 at 21.BBC, i*bid*.

2.1 Ownership of Mineral Rights

The Federal government owns all the mineral resources found within the boundaries of Nigeria. This right of ownership is a continuation of the colonial system[16] whereby the British Crown divested private and communal land-owners of rights to minerals found in their land and vested them in Nigeria as an entity.[17] After independence in 1960, the *Petroleum Act*[18] was enacted to confirm Nigeria's ownership of all petroleum found within its boundaries.[19] Petroleum is defined in the Act as including natural gas as it exists in its natural state in strata[20]

The *Constitution of the Federal Republic of Nigeria* 1999 [1999 Constitution], now specifically vests title in all minerals, mineral oils and natural gas in, under or upon any land[21] in Nigeria or in, under or upon the territorial waters and the exclusive

[16] Nigeria was a colony of the Great Britain until October 1, 1960, when she gained her independence. See G. Etikerentse, *Nigerian Petroleum Law*, 2nd ed. (Lagos: Dredew Publishers, 2004) at 8 [Etikerentse].

[17] See *Mineral Oil Act*, LFN 1958, c.120 [*Mineral Oil Act*] as rep. by the *Petroleum Act* 1969, LFN 2004, c. P10 [*Petroleum Act*] as am. by *Petroleum (Amendment) Decree* No. 16 of 1973. S. 3(1) of the Act provided that the entire property in and control of all mineral oils on, under, or upon any lands in Nigeria and of all rivers, streams and water courses throughout Nigeria was vested in the Crown. See M. A. Ajomo, "International and Municipal Legal Systems and the Oil and Gas Industry" (Paper presented at the University of Lagos Consult Seminar on Essential of Oil and Gas Law, May 14 – 16, 1996) [Unpublished] at 9 [Ajomo]; Andrew I. Chukwuemerie, "Ownership of Associated and Discovered Gas in Nigeria Under the Old Joint Venture Contracts" (2003) 27:1 OPEC Review 9 at 12 [Chukwuemerie].

[18] *Ibid*.

[19] That is, ownership of all mineral resources found in, under or upon any lands in Nigeria, under the territorial waters of Nigeria, or which forms part of the continental shelf. See *Petroleum Act*, *ibid*, s. 1(2). By a 1998 amendment of the *Petroleum Act*, the federal government ownership of petroleum now extends to all petroleum in the exclusive economic zone (EEZ) of Nigeria. See *Petroleum Act*, *ibid*. s. 1(2)(d). Nigeria's EEZ is an area extending from the external limits of the territorial waters of Nigeria up to a distance of 20 nautical miles from the baseline from which the breadth of the territorial waters of Nigeria is measured. See *Exclusive Economic Zone Act*, LFN 2004, c. E17, s. 1 [EEZ Act]; s. 2 of the EEZ Act also vests sovereign and exclusive rights with respect to the natural resources of the seabed, subsoil and superjacent waters of the EEZ in the federal Government. See Emmanuel I. Kachikwu, "Legal Issues in Oil and Gas Industry", (1989) 2 GRBPL 33 at 35; *supra* note 12 at 9.

[20] Natural gas itself is defined as "gas obtained from boreholes and wells and consisting primarily of hydrocarbons"). See *Petroleum Act*, *ibid.*, s. 15.

[21] *Petroleum Act*, *supr*a, note 17, s. 1(2) provides that "land" includes land covered by water.

economic zone in the Federal government.[22] As a result, there is no state, communal, or private ownership of mineral resources, including natural gas, in Nigeria.[23]

Apart from the ownership rights, the Federal government also has exclusive legislative power over the regulation of the development of the nation's oil and gas.[24] The ownership and regulatory rights are exercised by two different institutions. The Nigerian National Petroleum Corporation ("NNPC") exercises the Federal government's ownership rights, while the Federal Ministry of Petroleum Resources exercises the regulatory rights.[25] The different functions are both examined below.

2.1.1 The Nigerian National Petroleum Corporation

The NNPC was established under the *Nigerian National Petroleum Corporation Act* (NNPC Act)[26] as an agency of the Federal government. It is charged with the duty of engaging in all phases of petroleum activities in Nigeria and also to actively control and supervise the operations of the oil and gas industries.[27] By virtue of the Act, the Federal

[22] LFN 2004, c. W5, s. 44(3). This provision can also be found in the 1960, 1963, and 1979 Constitutions of Nigeria. See Chukwuemerie, *supra* note 17 at 12.

[23] Compare this with the situation in Canada, where, with the exception of most of the Western and Maritime provinces, private ownership of mineral resources is the norm. See Omorogbe, *Oil and Gas Law in Nigeria*, (Lagos: Malthouse, 2001) at 31-34 [Omorogbe, Oil and Gas Law]; *supra* note 11 at 9; Ballem, *The Oil and Gas Lease in Canada*, 3rd ed. (Toronto; University of Toronto Press, 1999) at 12-14.

[24] See *supra* note 22, sch. II, part I, item 39. "Mines and minerals, including oil fields, oil mining, geological surveys and natural gas" is an item listed under the Exclusive Legislative List. The power to make laws concerning the items in this list is vested exclusively in the National Assembly for the Federation. The National Assembly exercises the legislative powers of the Federal Republic of Nigeria. See *supra* note 22, s. 4 (1) & (2).

[25] See *supra* note 5 at 9; Ibibia Worika, "Energy Development and Utilization in Africa" in Adrian J. Bradbrook, *et al*., eds., *The Law of Energy for Sustainable Development* (Cambridge: Cambridge University Press, 2005) 324 at 349[Worika]; Adetutu Oshineye, "The Petroleum Industry in Nigeria: An Overview" (2000) 4:4 Modern Practice J. Finance & Investment Law 325 at 329 [Oshineye].

[26] No. 33 of 1977, LFN 2004, c. N123.

[27] The creation of the NNPC was a result of the following International Resolutions which sought to re-affirm the inalienable right of all countries to exercise permanent sovereignty over their natural resources in the interest of their development as a universally recognized principle of public law: *Permanent Sovereignty Over Natural Resources*, GA Res. 1803 (XVII), 17 UNGAOR, Supp. No. 17, UN Doc. A/5217 (1962) 15; *Declaration on the Establishment of a New International Economic Order*, GA Res. 3201(S-VI) UNGAOR, 6th Sess., Supp. No 1, UN Doc. A/9559 (1974) 3; Article 2 of *Charter of Economic Rights and*

government vested in the NNPC, all the mineral resources that it had initially vested in the then Federal Ministry of Petroleum Resources and the Nigerian National Oil Corporation ("NNOC").[28] The NNPC was formed through the merger of the Federal Ministry of Petroleum Resources and the NNOC. It succeeded the NNOC in all aspects and assimilated the Ministry of Petroleum Resources' regulatory functions under a Petroleum Inspectorate Department.[29]

The NNPC exercises control and supervision over the oil and gas industry principally through the acquisition of participation interests in the major oil companies' working interests.[30] These participatory interests are exploited in conjunction with the companies under various contractual arrangements, like the joint venture arrangement. The joint venture arrangements in Nigeria are defined primarily by the lease, the Participation and the Operating Agreements and secondarily by the Memorandum of Understanding (MOU). These Agreements designate the operator of the joint venture, specify each partner's share in the cost of petroleum operations, and indicate petroleum profit tax and royalty obligations. While the MOU is designed to provide attractive fiscal

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Duties of State, GA Res. 3281 (XXIX) UNGAOR, 29th Sess., Supp. No. 31 (1974) 50; and *Declaratory Statement of Petroleum Policy in Member Countries*, Organization of Petroleum Exporting Countries (OPEC) Res. XVI.90 OPEC, (1968) [OPEC Res. XVI]. See Omorogbe, Oil and Gas Law, *supra* note 23 at 34-37; *supra* note 17; *supra* note 7 at 20-23; Odumosu, "Transferring Alberta's Gas Flaring Reduction Regulatory Framework to Nigeria: Potentials and Limitations" (2007) 44 Alta. L. Rev. 863 at 875.

[28] See *supra* note 26, s. 5, sch. II, part B, s. 23(2). The then Federal Ministry of Petroleum Resources was established in 1975 to mainly enforce regulations relating to the operations of the oil companies in order to ensure their compliance with good oil field practice. While the NNOC was established by Act No. 18 of 1971 to mainly acquire the asset and liability in the existing oil companies on behalf of the Nigerian Government and also participate in all the phases of the petroleum industry. See *supra* note 11 at 202-203; *supra* note 5 at 9.

[29] See NNPC Act, *ibid.* ss. 10 -11. This Department was headed by a Chief Executive who reported only to the Petroleum Minister in the NNPC hierarchy establishment. See *supra* note 16 at 20.

[30] See *supra* note 16 at 19-20.

incentives to the participating oil corporations in exchange for increased investments and efficient operations.[31]

By a 1988 restructuring, the Petroleum Inspectorate Department was excised from the NNPC and re-established as the Department of Petroleum Resources ("The Department"),[32] a department in the Ministry of Petroleum Resources ("The Ministry") that had been re-established in 1986.[33] The NNPC now stands as a monolithic corporate entity headed by a Group Managing Director[34] with six directorates. It has ten subsidiary companies, two joint ventures and about ten affiliated companies, which are engaged in a variety of upstream and downstream activities.[35] The National Petroleum Investment Management Services ("NAPIMS"), a subsidiary of NNPC, monitors and supervises all aspects of the government's investments and participation in the oil industry.[36] As a result, the NNPC enjoyed an enviable status amongst all the Nigerian government establishments.

This status has since waned as a result of the re-establishment of the Ministry and the Department,[37] lack of adequate funding from the Federal government on whom the

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[31] *Ibid*. at 23; Omorogbe, Oil and Gas Law, *supra* note 23 at 47; *supra* note 5, at 16.

[32] With the commercialization of NNPC, the Petroleum Inspectorate Division was excised from the NNPC in 1988 due to the non-commercial nature of its functions. Department of Petroleum Resources, "Historical Background", online: Department of Petroleum Resources <http://www.dprnigeria.com/aboutus.html> [DPR]. However, Part II of the NNPC Act, *ibid*., *supra* note 26 is yet to be amended or deleted in order to bring it into conformity with the transfer. See *supra* note 11 at 227; Worika, *supra* note 25 at 350.

[33] The Ministry was established in 1975 and merged with the NNOC to form the NNPC in 1977. It was later re-established in 1986. See *supra* note 16 at 19-21; *supra* note 3 at 25.

[34] The Group Managing Director reports to the Chairman of the Board of the NNPC, the Federal Minister of Petroleum Resources. See NNPC Act, *supra* note 26, s. 1(3).

[35] See NNPC, "About NNPC", online: NNPC <http://www.nnpcgroup.com/aboutus.htm>; Centre for Petroleum Information, "Nigerian National Petroleum Corporation (NNPC)", online: CPI <http://www.petroinfonigeria.com/nnpc.html>; *supra* note 5 at 56.

[36] *Supra* note 5 at 56.

[37] Subject to the privileges, exemptions and restrictions provided for the benefit of the NNPC the NNPC *Act*, the NNPC comes under the regulatory duties, powers and supervision of the Department in so far as the activities of the corporation are those of a permit holder, licensee or lessee, as the case may be, under the *Petroleum Act*, *supra* note 17 & the *Oil Pipelines Act*, LFN, 2004, c. O7 [Oil Pipelines Act]. See NNPC

NNPC is dependent financially,[38] the action or inaction of some of its subsidiaries[39] and acts of corruption exhibited by its management board.[40] Nevertheless, the NNPC still remains a force to be reckoned with in the Nigerian Petroleum Industry. In its relatively short history, it has grown to become a fully integrated oil and gas company on its own account and indirectly through its joint venture relationship with other petroleum companies.

2.1.2 The Federal Ministry of Petroleum Resources

The Ministry is charged with the formulation and implementation of the Federal government's petroleum policies and the general management and operation of the petroleum industry. Its duties include representing the Federal government on petroleum matters at domestic and international levels, the issuance of licenses to operators engaged in any petroleum activity, and ensuring compliance with all applicable statutes.[41]

Until recently, the Ministry was headed by the President, with the responsibilities of the office being discharged jointly by the office of the Special Adviser to the President on Petroleum Affairs and the Group Managing Director of NNPC. The Ministry is now headed by the Minister of Petroleum Resources. [42]

Act, *supra* note 26, s. 20. The Ministry of Petroleum Resources is the supervisory Ministry of the NNPC. See *supra* note 11 at 228.

[38] This lack of fund restricts the NNPC from meeting its joint venture obligations timeously. According to Etikerentse, *supra* note 16 at 21, this portrays the NNPC as an ineffective and inefficient organization.

[39] For example, the action or inaction of the Pipelines and Product Marketing Company (PPMC), a subsidiary of NNPC, has been blamed for the frequent fuel scarcity experienced in the country over the past few years. See *ibid*.

[40] In the words of a learned author, the NNPC is an essentially weak organization where waste abounds. See *supra* note 3 at 26; *supra* note 16 at 21.

[41] See generally *Petroleum Act*, *supra* note 17, ss. 2-4, 8 (1) (a) – (h) & 9; Federal Government of Nigeria, "Assignment of Responsibilities", Federal Government of Nigeria Official Gazette (3 March 1989); *supra* note 5 at 59 and Worika, *supra* note 25 at 350.

[42] See Uchenna Izundu, "Nigeria's President Assumes Energy Minister Role" (20 August 2007) 105:31 the Oil & Gas Journal at 33 [Izundu, Nigeria's President]. It wasn't until the cabinet reshuffle of 17 December 2008, that Mr. Rilwanu Lukman, a former OPEC Chief, was appointed as the Minister for

The Department, which was once the inspectorate arm of the NNPC, is now a department in the Ministry. It is the technical, supervisory and enforcement arm of the Ministry.[43] It is headed by a Director General who is responsible for setting standards for the effective control of the petroleum industry. The Department is responsible for policy formulation and the regulation of the industry,[44] including resource management through the allocation of licenses and licenses, inspections, and technical control in the downstream sector.[45] While the final regulatory powers of the Department rest with the Minister, who is still closely associated with the NNPC,[46] the separation of the Department from the NNPC is nevertheless preferable, from a regulatory point of view, to a system in which NNPC was responsible for issuing licenses to its competitors and itself (in the case of companies in which it has a participatory interest).[47]

Even if the Department is ascribed the role of the oil industry regulator, as it seems to be, there remains an inherent regulatory problem because the Department is still closely linked to the NNPC. To be efficient and effective, the Department must be independent and answerable to an authority other than the Minister, who is also the Chairman of the board of the NNPC.[48] In Alberta, the main regulatory body, the Energy Resources and Conservation Board ("the Board"), although a part of the Ministry of

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Petroleum Resources. See Izundu, Nigeria's New Petroleum Minister, *supra* note 14. See *supra* note 5 at 59; Worika, *supra* note 25 at 350.

[43] *Supra* note 11 at 228.

[44] *Ibid*. at 229.

[45] The downstream sector of the petroleum industry is constituted by those establishments which provide transportation, refining, distribution services as well as petrochemical production and distribution services. The upstream sector, on the other hand, is made up of exploration and production companies. See Oshineye, *supra* note 25 at 328.

[46] By s. 1(3) of the NNPC Act, *supra* note 26, the Minister of Petroleum Resources is also the Chairman of the Board of Directors of the NNPC.

[47] See *supra* note 3 at 25.

[48] See NNPC Act, *supra* note 26, s. 1(3).

Energy, makes its decisions independent of the Ministry.[49] This independence ensures that the Board is able to develop the province's mineral resources in an effective manner.

The government is taking steps to improve the way the oil and gas industry is being managed.[50] The instrument for the proposed reform is the *Petroleum Industry Bill*, 2008,[51] which is currently being deliberated on in the House of Representative.[52] The main feature of this Bill is that it consolidates existing laws governing the administration of the oil and gas industry.[53] The Bill provides for an autonomous regulatory body to replace the DPR. The body will have financial and operational independence to regulate the activities in the upstream petroleum sector.[54] The Bill also provides for the full commercialization and the decentralization of the functions of the NNPC, by creating a new company to be known as the National Oil Company.[55]

According to Umaru Musa Yar'Adua, the sponsor of the Bill, the reasons for the reform is to ensure the efficient, safe, effective and sustainable infrastructural development of all sectors of the oil and gas industry and also to promote the conduct of operations in the industry in an environmentally acceptable manner.[56] If the reform is to

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[49] See above, Part 2, section 3.3.1.

[50] The government's action follows reports published in 2000 by the Oil and Gas Industry Reform Committee and the National Council on Privatization, which proposed new operational models for the energy ministry and the NNPC. See Uchenna Izundu, "Nigeria to Restructure Energy Industry under New Policy" (2007) 105:34 the Oil & Gas Journal at 24 [Izundu, Nigeria to Restructure]. See also John-Abba Ogbodo, "Govt Set to Unbundle NNPC, Scrap DPR" *The Guardian* (5 January 2009) online: <http://www.ngrguardiannews.com/news/article01//indexn2_html?pdate=050109&ptitle=Govt%20set%20to%20unbundle%20NNPC,%20scrap%20DPR> [Ogbodo]; "Nigeria Oil Giant, NNPC Will Become Real Company: President" *Agency France Press* (17 May 2008) online: Agency France Press <http://afp.google.com/article/ALeqM5hXUb3WwdviEMRPCZMU4KO1ru3R7w>.

[51] HB 159, C4757, online: National Assembly of Nigeria <http://www.nassnig.org/legislation.php?page=6&year=2008>.

[52] The Bill passed first reading in the House of Representative on 16 December 2008. It is presently awaiting second reading. See House of Representatives, Federal Republic of Nigeria, Fourth Republic, 3rd National Assembly, Second Session, No. 55, Votes and Proceedings, 16 December, 2008 at 393.

[53] See NNPC, "Petroleum Industry Bill", online: NNPC <http://www.nnpcgroup.com/pib/faq.html>.

[54] *Ibid*., Cap. iii.

[55] *Ibid*., Cap. vi.

[56] Ogbodo, *supra* note 50.

be taken seriously, it is submitted that the issue of regulation has to be given a closer and more serious attention.

2.2 Modes of Acquisition of Natural Gas Rights

The essence of a government's sovereignty over its mineral resources is its ability to allocate its resources as it deems fit. Prior to 1970, when Nigeria became a member of the Organization of Petroleum Exporting Countries ("OPEC"),[57] the Nigerian Government allocated this right solely through the instrumentality of concessions.[58] In line with OPEC Resolution XVI,[59] Nigeria has since departed from using this method

[57] Nigeria became a member of OPEC in 1971. OPEC was established in 1960 by Iran, Iraq, Kuwait, Saudi Arabia, and Venezuela with the main objective of tilting the erstwhile contractual scale in favour of its member nations. Its membership has since increased to 13. According to Ajomo, the organization has emerged as the only permanent producers' intergovernmental organization which co-ordinates oil policies all over the world and defends the common petroleum interests of under-developed countries. Since its formation, OPEC has remained at the hub of the international legal system not only in respect of oil pricing, but also as to what the level of production should be. See Ajomo, *supra* note 17 at 5. See also *supra* note 16 at 18.

[58] A concession is an arrangement between governments and oil companies for the exploration and production of petroleum. The company fully bears all risks and costs of exploration, development, and production. It has interests in the crude oil produced and is liable for all royalty and petroleum profit tax payments. Traditionally, concessions were for much longer duration and larger areas. In several instances, such concessions extended over the whole of the national territory and lasted for as long as 40-75 years. According to Omorogbe, the company was often granted extensive rights over all the mineral deposits in the area. It was an exclusive owner and was free to dispose of them as it saw fit. In return, it paid some specified costs, taxes and royalties. Financial benefits accruing to the host states were usually minimal. In Nigeria, Government's interest was limited to the collection of taxes and rents or royalties, and such royalties were based on volume of output, rather than value. The oil companies more or less determined both the production and price levels of Nigerian crude oil. Legislation passed at this time reflected the dominance of foreign oil companies in that significant incentives were given to explore and produce, sometimes at the expense of Nigeria's interest. See Omorogbe, *Oil and Gas Law*, *supra* note 23 at 39, 47; *supra* note 3 at 15, 19; *supra* note 3 at 1.

[59] *Supra* note 27. The resolution enjoined member states to "seek participation in the equity of existing concessions". As a result of this resolution and the apparent inequities with this arrangement,, Nigeria embarked upon a nationalization of the foreign interest of most of the business in Nigeria (note that in the case of the upstream petroleum companies, government acquisition did not extend to the ownership of the shares in the company; but just in their operation) and also took participatory interest in the existing concession. This participation, which is usually by way of a joint venture, takes the form of a 60% equity interest in foreign producing ventures. Thus where such traditional concessions exist today, they are jointly operated by the lessee and the Nigerian Government through the NNPC. See *Nigerian Enterprise Promotion Act*, LFN 1990, c. 303. See also Uchegbu, A.U. "Adaptation and Application of International Laws to Nigeria's Oil Industry", (1989) 2 GRBPL 42 at 43; *supra* note 16 at 16, 60; Omorogbe, *Oil and Gas Law*, *supra* note 23 at 39, 47; *supra* note 3 at 18, 20-22; *supra* note 5 at 8.

and now adopts other methods, like the oil exploration license ("OEL"), oil prospecting license ("OPL"), the oil mining lease ("OML"), the production sharing contract ("PSC") and the service contract ("SC").[60] The OEL, OPL and OML, examined below, are the only types of rights granted under the *Petroleum Act*.[61]

2.2.1 The Oil Exploration License, Oil Prospecting License and Oil Mining Lease

The OEL and the OPL are contractual arrangements for pre-production operations, while the OML is for production operations and related activities.[62] The OEL is usually granted in respect of a compact area not exceeding 12,950 square kilometers. It confers upon the grantee the non-exclusive rights to explore for petroleum in the area of grant. The initial life span does not exceed one year, although it may be renewed for another year. The Federal government has proprietary rights to the seismic data gathered by the licensee.[63]

The OPL conveys an exclusive right to explore and prospect for petroleum within the area of the license. Its duration does not exceed five years including renewals. The grantee is entitled to carry away and dispose of petroleum won during the prospecting

[60] The PSC and SC are types of contract arrangements under which the government reserves its property right to the petroleum *in situ.* Here, the NNPC employs an oil company as a contractor to carry out exploration and production activity on designated concessions. The company bears the entire risk capital for exploration and production. Where oil is discovered in commercial quantities, the contractor recovers his costs, in the case of a PSC, from the crude produced and the remaining crude is shared between the parties. While in the case of an SC, costs are recouped in cash and the contractor is paid in cash, with an option for payment to be made with crude oil, as in the case of a PSC. Unlike the SC, the PSC is commonly utilized, perhaps because it is statutorily authorized, although both modes are not as common as the OEL, OPL and OML. See the *Deep Offshore and Inland Basin Production Sharing Contracts Act* No. 9 of 1999, LFN 2004, c. D3; *supra* note 5 at 159-169.

[61] See *supra* note 17, s. 2 & sch. 1.

[62] *Ibid*.

[63] See the *Petroleum Act, ibid*., sch. 1, para. 1; *Petroleum* (*Drilling and Production*) *Regulations*, L.N. 69, 1969, Reg. 12 [*Petroleum Regulations*]. The OEL has to all intent and purposes falling into disuse, although it remains in the Petroleum Acts and other related statutes. The present practice is that the country engages the services of a seismic gathering company and such seismic information is available for perusal by oil companies at the office of the DPR upon payment of a fee. The OEL may however still be relevant, given the little information that is known about the availability of natural gas in sedimentary basins other than the Niger Delta. See generally, *supra* note 5 at 108-109.

operations, subject to fulfillment of special terms imposed under the *Petroleum Act*, the *Petroleum Profit Tax Act* and any other law imposing taxation in respect of petroleum.[64]

The OML is a modern form of concession that is granted to the holder of an OPL which has satisfied all the conditions imposed by the license or, otherwise, by the *Petroleum Act*, and has also discovered oil in commercial quantities.[65] The OML grants an exclusive right to conduct exploration and prospecting operations within the leased area, and to win, work, store, carry away or otherwise treat petroleum in or under the leased area. It is granted for a term not exceeding 20 years, although it may be renewed if the lessee has paid all rents and royalties due and has also performed all its obligations under the lease.[66] The OML is granted subject to the rights of the Federal government to participate in the venture to which it relates.[67] This explains why the OML now widely exists as one of the constituent agreements underlying most joint ventures between the Nigerian government and the oil companies.[68] For ease of reference, the holder of an OEL, OPL or an OML will subsequently be referred to as a lessee.[69]

The OEL and OPL are acquired either through "Discretionary Licensing" or "Auction". By virtue of the *Petroleum Regulations*, a direct grant may be made, in respect of any uncommitted block, to an applicant that satisfies the applicable statutory requirements.[70] Here, the first qualified person to apply may be issued the license at the absolute discretion of the Minister. The discretionary method has the attributes of

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[64] See *Petroleum Act*, *ibid*., sch. 1, para. 5-6; *supra* note 5 at 109.
[65] Oil is deemed to be discovered in commercial quantities if shown that the licensee is capable of producing at least 10,000 barrels per day of crude from the licensed area. See *Petroleum Act*, *ibid*., sch. 1, para. 8-9.
[66] *Ibid*., sch. 1, para. 10-16. Strangely, the law is silent on the term of the renewed period.
[67] *Ibid*., sch. 1, para. 34.
[68] See Omorogbe, *Oil and Gas Law*, *supra* note 23 at 41.
[69] For a long time, this was the term used to refer to a grantee of oil and gas rights and it is still to be found in most oil and gas statutes.
[70] See *supra* note 63, Reg. 1-3.

selectivity in the choice of prospective licensees and the minimization of costs and bureaucracy. On the other hand, the method is bedeviled with disadvantages such as the inability of the government to properly evaluate the fair market value of petroleum acreages, corruption, a lack of transparency and accountability, including, arbitrariness in allocation of acreages, as well as the inability of the government to attract truly competitive offers from multinational corporations.[71]

The auction method is a recent development in Nigeria.[72] It arose as a result of the defects in the discretionary licensing mode. In auctions, grants over open petroleum acreages are offered on the basis of competitive tenders. The method, which is successfully being employed in Alberta, does not have the disadvantages of discretionary licensing and it ensures the receipt of a fair market value for the acreages.[73] Unfortunately, unlike in Alberta, this method is not statutorily regulated in Nigeria. In order to ensure its effectiveness, it will be necessary to make provision for it in the *Petroleum Regulations*.

In exchange for the grant of licenses and leases, the government derives bonuses, rents, royalties on natural gas produced, tax on operating profits and petroleum profit tax.[74] Only the royalty and tax regime will be examined, since they make up the bulk of

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[71] See *supra* note 5 at 106; *supra* note 11 at 15.

[72] The first ever licensing round was conducted on February 26, 1970, when the government announced open bidding for 27 offshore acreages of which 12 were reserved for the proposed NNOC. See *supra* note 5 at 107.

[73] See Ministry of Petroleum Resources, "Guidelines for Offer of Open Acreages for Petroleum Exploration and Production in Nigeria", Ministry of Petroleum Resources, 2000. See generally *ibid*.; supra note 11; Edward Vera-Cruz, "Nigeria Licensing: Notes for Prospective Bidders" (2000) 18 J. Energy, Nat'l Res. L. 301.

[74] Two types of bonus payment obtain in Nigeria: the signature bonus, which is paid at the time of the acquisition of the right and the production bonus, which is paid when production reaches a mutually agreed level. Signature bonuses are sometimes regarded as onerous by the lessees because they are additional pre-discovery costs that increase initial expenditure, for instance, for the 1991 bidding round, the prospective contractor companies paid bonuses of US$1 million each. However, the lessee's perception of both signature and production bonuses depends on the type of discovery made and the prevailing economic

government revenue. Royalties are governed by the *Petroleum Act* and *Petroleum Regulations*.[75] Offshore royalty rates are also provided for in the *Deep Offshore and Inland Basin Production Sharing Contract Decree No. 9* of 1999.[76] The applicable rates for both onshore and offshore areas are graded. The grades reflect the increased difficulties and higher technology and expertise necessary for deepwater production.[77]

Taxes on petroleum are governed by the *Petroleum Profit Tax Act*.[78] The Act applies to the taxation of incomes of companies engaged in petroleum operations.[79] The normal petroleum profit tax rate is 85%.[80] Certain deductions, in respect of monies spent and investments made by the company, are allowed to be made from the profit before the tax rate is ascertained.[81] More specifically, natural gas taxation is governed by the law regulating the liquefied natural gas project and the *Associated Gas Framework Agreement*.[82] The provisions of these laws are reviewed in more detail in section 4.1 of this Part.

Unlike Alberta, Nigeria does not have a non-renewable natural resources savings fund. It is necessary to have such a fund so that a certain percentage of the revenue derived from the disposition of the country's natural gas resource will be reserved in it

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condition. Rents for oil licenses and leases are as specified in the *Petroleum Act*, *supra note* 17, sch. 1, para. 32 and *Petroleum Regulations*, *supra* note 63, Reg. 60(2). Rents paid for non-producing areas are credited 100% against petroleum profits tax, while rents for producing leases are credited 85% against royalty payments. See generally Omorogbe, Oil and Gas Law, *supra* note 23 at 65-79; Kachikwu, *supra* note 38 at 38.

[75] *Petroleum Act*, *ibid*., sch. 1, para. 33 and the *Petroleum Regulations*, *ibid*., Reg. 61.

[76] *Supra* note 60.

[77] The grades are as follows; onshore: 20%, offshore: 0 -100 metres water depth - 18%, 100-200 metres - 16.67 %, 201-500 metres water depth - 12.00%, 501- 800 metres water depth - 8%, 801-1000 metres water depth - 4 %, beyond 1000 metres water depth - 0%. See *ibid*. s. 5(1); Omorogbe, Oil and Gas Law, *supra* note 23 at 71- 72.

[78] LFN 2004, c. P13.

[79] *Ibid*., s. 2.

[80] *Ibid*., s. 21.

[81] *Ibid*., s. 10.

[82] Omorogbe, Oil and Gas Law, *supra* note 23 at 66- 71.

for future use. When the resource is depleted, such fund will continue to generate interest payments which can provide social services to Nigerians who will no longer benefit from the resource-generated revenue enjoyed by earlier generations.[83] According to Weaver, this type of trust fund can be a useful device to assure intergenerational equity, but it reduces the investment funds currently available for social infrastructure and economic diversification.[84] In a nation like Nigeria with pressing immediate needs to solve problems of social equity, poverty and health, this trust fund may seem a luxury. Nonetheless, Nigeria should engage in long-term planning for the day when its resources run out. Effective development requires that Nigeria save and invest in social capital at a rate which, to an extent, replaces the natural resources capital being depleted. An in-depth review of the rights granted to a lessee will now be conducted.

2.2.1.1 Surface Rights

The *Land Use Act* vest all lands comprised in the territory of each State solely in the Governor of the State in trust for all Nigerians.[85] The Act empowers the Governor to grant a statutory right of occupancy to eligible persons.[86] These rights of occupancy can be revoked for overriding public interest.[87] The Act defines overriding public interest as including the requirement of the land for mining purposes or any purpose connected

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[83] Jaqueline Weaver, "Sustainable Development in the Petroleum Sector" in Adrian J. Bradbrook & Richard L. Ottinger, eds., *Energy Law and Sustainable Development* (Gland: International Union for Conservation of Nature and Natural Resources, 2003) 45 at 52 [Weaver, Sustainable Development].
[84] *Ibid.*
[85] LFN 2004, c. L15, s. 1 [*Land Use Act*]. However by s. 49, any land vested in the Federal Government or any of its agencies is exempted. The Act theoretically put an end to private ownership of land in Nigeria and shifted both economic and legal emphasis from land ownership to land use. See Momodu Kassim-Momodu, "Impact of the Land Use Act on Petroleum Operations in Nigeria" (1990) 8 J. Energy, Nat'l Res. L. 291 at 296 [Momodu, Impact of the Land Use Act]; A.N. Allott, "Nigeria: Land Use Decree, 1978" (1978) 22 J. Afr. L. 136.
[86] In the case of non-urban land, customary right of occupancy is to be granted by the Local Government. See *Land Use Act, ibid*., ss. 5 & 6.
[87] *Ibid.*, s. 28(1).

therewith.[88] Where the revocation is for this purpose, compensation, as calculated under the provisions of the *Minerals Oils Act* or any replacement legislation, is required to be paid to protected persons.[89] These persons[90] are also required to be compensated by the lessee for the disturbance of their surface and other related rights, irrespective of the nature of that disturbance.[91] The Minister is enjoined not to give his consent for the lessee to enter or make use of the land described in his concession, unless this compensation is shown to have been paid.[92]

According to Kachikwu, the effect of the requirement to pay compensation has been to raise questions as to whether the Government's ownership right to all the land and petroleum resources of Nigeria is total or partial.[93] While the compensation for revocation of a right of occupancy for mining purposes[94] is required to be paid without more,[95] compensation for revocation for other purposes[96] is required to be paid only in respect of unused improvements on the land.[97] It therefore appears that the compensation contemplated in the former case is for the value of the land including any improvement thereon, therefore bestowing rights akin to ownership on the protected person.

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[88] *Ibid*., s. 28(2)(c) & (3)(b).
[89] See *ibid.*, s. 29(2). Although this compensation is required to be paid by the oil company to the Governor, in practice, after the payment to the governor, so as to ensure peaceful possession, the lessee still pays compensation to the protected person as they receive little or nothing from the Governor. Disputes over the quantum of compensation are settled administratively by the Land Use and Allocation Committee. This is because the *Land Use Act*, *ibid*, bars the court from hearing such disputes. See *supra* note 5 at 196-200.
[90] A protected person is the owner(s) (or as is now the case, person(s) having rights of occupancy, or lawful occupier(s) of a land in Nigeria. *Land Use Act*, *ibid*. ss. 34, 36.
[91] See *Petroleum Act*, *supra* note 3, sch. 1 para 37.
[92] See *Petroleum Regulations*, Reg. 17(1)(C)(ii), *supra* note 63.
[93] Emmanuel I. Kachikwu, "Legal Issues in Oil and Gas Industry", (1989) 2 GRBPL 33 at 36. See also Momodu, Impact of the Land Use Act, *supra* note 85 at 296-299.
[94] *Supra* note 85, s. 28(2)(c) & (3)(b).
[95] *Ibid*., s. 29(2).
[96] *Ibid*., s. 28 (2) (b) and (3) (C).
[97] *Ibid*., s. 29(1).

It is contended that a right to compensation, whether "without more" or for "unused improvements", does not bestow a right of ownership on the protected persons. The right to compensation can, for example, be likened to the right of a tenant, under Property Law, to have quiet enjoyment of his property. A protected person, not being the owner of the land, cannot be compensated for the value of the land. The only compensation that might legally be due to such person would be for his or her unused improvements on the land. Therefore the right to compensation cannot in any way amount to a right of ownership so as to diminish the government's ownership rights.

2.2.1.2 Rights to Natural Gas

The question has often arisen as to whether a lessee owns the gas it discovers or which it produces in association with crude oil.[98] This question is of practical relevance, because, quite contrary to its approach to crude oil, Nigeria has over the years taken some legislative steps that suggest an intention to own all the natural gas within its shores, including associated and produced gas. It is therefore important to determine the lessee's rights, so as to serve as a guide to the country's policy makers and also present and prospective investors.[99]

It is clear from earlier discussions that the Federal government owns the petroleum found within its boundaries. But where a concession or lease is granted, the lessee is deemed to own the petroleum (which includes crude oil and natural gas)[100] that is found in the course of exploring, prospecting, or otherwise working an oil field or

[98] See Chukwuemerie, *supra* note 17 at 9; *supra* note 16 at 212-216; Momodu Kassim-Momodu, "Legal Aspects of Ownership of Natural Gas in Nigeria" (1988) 6 J. Energy, Nat'l Res. L., 268 [Momodu, Legal Aspect of Ownership].
[99] An investor would want to know his rights to the natural gas it discovers within the area of grant before he embarks on an expensive natural gas utilization project.
[100] See *Petroleum Act*, *supra* note 17, s. 15.

prospective field.[101] One would therefore assume that whatever rights of ownership the lessee can exercise over the crude oil it finds in the area of grant, it should be able to exercise similar rights over non-associated or associated gas that it finds in the same area. This may not be the case, as government policies and the uncertain provisions of legislation on petroleum and natural gas have combined to create doubts over the ownership of such gas.[102]

The uncertainty stems from the definition of Petroleum in the *Petroleum Act*[103] and the history of natural gas development in Nigeria. Just as in the case of Alberta, crude oil has always been given a pride of place in many aspects of Nigerian petroleum regulation and little regard has been paid to the natural gas constituent of the hydrocarbon.[104] From the 1914 *Minerals Oil Act* up until 1969, when the *Petroleum Act* was enacted, all enactments in the Nigerian petroleum industry had concerned themselves only with crude oil and natural gas was somehow forgotten. Even the titles of the statutes reflected that. Also the types of rights that were granted, i.e. the OEL, OPL and OML, were focused on crude oil alone as evidenced by their nomenclature and the substances granted.[105]

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[101] *Ibid*., s. 2(1). Chukwuemerie argues that the right given to a lessee to "conduct exploration and prospecting operations and to win, work, store, carry away, transport, export or otherwise treat petroleum discovered in or under the concession area, or the products thereof without interruption, claim or disturbance from or by the minister or any other person" as stated in the *Petroleum Act*, *ibid*., sch. 1, para. 11 and the OML, translates to a right of ownership. See Chukwuemerie, *supra* note 17 at 13.

[102] Note that this question will not arise in respect of OML managed under PSCs and SCs. Here, such gas belongs wholly and completely to the Federal Government through the NNPC. See *supra* note 16 at 213-215; Chukwuemerie, *supra* note 17 at 19-20.

[103] *Supra* note 17, s. 15.

[104] This was mainly because natural gas had no commercial worth and significance at the time.

[105] First the three grants (OEL, OPL, and OML) are all for crude oil component of the petroleum; without natural gas being emphasised therein. Second, natural gas is not even brought into reckoning in the determination of whether or not, a licensee can be deemed to have discovered petroleum in commercial quantities. The yardstick or gauge to be used is the licensee's capability of a daily production of at least 10,000 barrels of crude oil for the qualification for the grant of an OML from an OPL status. See *Petroleum Act*, *supra* note 17, sch. 1, paras. 8-9. See also Chukwuemerie, *supra* note 17 at 11; *supra* note 16 at 213.

It might have been expected that the *Petroleum Act* would have distinct provisions on the acquisition of natural gas, such as those found in Alberta legislation. In Alberta, the Crown licenses and leases grant rights to petroleum or natural gas, or both.[106] Unfortunately, there are no such provisions in Nigeria. What exist are licenses and leases that grant rights, not just over crude oil (as was the case before the Act), but also over all the natural gas in the leased area.[107] Defining petroleum to include natural gas was not *ipso facto* wrong.[108] What was wrong was simply adopting the definition in the Act, without avoiding its likely adverse effect on the government's ownership rights to the non-associated and associated gas in the area.[109] What has happened is that such gas simply passes to the lessee by a legislative default.

Granted, a crude oil operator has a common law right to use natural gas to effectively exploit its oil,[110] but this right can be recognized by the government without necessarily handing over its ownership rights to all the natural gas in the leased area. In Alberta, this right is tacitly recognized in the definition of petroleum and natural gas in the MMA.[111] There, petroleum is defined as the production from any well that initially produces oil either alone or with gas at a low gas-oil ratio.[112]

It is contended that until the definition of petroleum in the *Petroleum Act*[113] is amended along the lines found in the MMA, the government may not be able to fully

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[106] See *Mines and Minerals Act*, R.S.A. 2000, c. M-17 [MMA] and the *Petroleum and Natural Gas Tenure Regulation*, Alta. Reg. 263/97 [Tenure Regulation].
[107] *Petroleum Act*, *supra* note 17, sch. 1, para. 11.
[108] In fact, this is the accepted practice in third world countries. See Chukwuemerie, *supra* note 17 at 14.
[109] The *Petroleum Act*, *supra* note 17, was made under a Military Government. Under the Military dispensation, proposed statutes were not subjected to informed general debate and were often made in a hasty manner. Chukwuemerie refers to this as legislative recklessness. See Chukwuemerie, *ibid.* at 13.
[110] See *Borys v. C.P.R. and Imperial Oil Ltd.*, [1953] 2 W.L.R. 225.
[111] MMA, *supra* note 106, 80 (2)(b).
[112] *Ibid*.
[113] *Supra* note 17, s. 15.

assert its ownership right to natural gas. Unfortunately, the government has not deemed it necessary to amend section 15, but has taken some other steps to achieve the same objective. These steps will be examined to determine whether they have indeed taken away the lessee's possible ownership right over the natural gas.

A. Regulation 43 of the *Petroleum Regulation*[114] requires a lessee to submit to the Minister, not later than five years after the commencement of production from the area covered by the license or lease, any feasibility study, programme or proposal that it "may have for the utilization of any natural gas, whether associated with oil or not, which has been discovered in the relevant area". The regulatory power of the government entitles it to impose conservation and related obligations on a lessee. Regulation 43 can therefore be said to be one of such obligations and not an exercise of an ownership right.

B. The *Associated Gas Re-injection Act,* 1979 ["Re-injection Act"],[115] which provides that, notwithstanding regulation 43,[116] every company producing oil and natural gas in Nigeria should, no later than 1 April 1980, submit to the Minister a preliminary programme or scheme for the viable utilization of all associated gas produced from a field or groups of field and project(s) to re-inject the gas that cannot be viably utilized

Second, it requires the submission of a detailed programme not later than 1 October 1980.[117] Thirdly, it forbids the flaring of natural gas by any company or person

[114] *Supra* note 63.
[115] LFN 2004, c. A25 as am. by *Associated Gas Re-injection (Amendment) Decree* No. 17 of 1985.
[116] *Petroleum Regulation, supra* note 63. Reg. 43 requires a lessee to submit an utilization programme to the Minister.
[117] Re-injection Act, *supra* note 115, ss. 1-2.

beyond 1 January 1984 (later extended to 1 January 1985[118]) without the permission of the Minister.[119]

It is submitted that the provisions of regulation 43 of the *Petroleum Regulation*,[120] and the Re-injection Act are not enough to divest the lessee of its interest in natural gas already granted by the *Petroleum Act*. The requirement of permission for flaring is not inconsistent with the ownership rights of the lessee. A power to control or stop gas flaring is not necessarily an exercise of ownership rights but rather the government's effort to reduce natural gas waste while also preventing damage to the environment from the adverse effects of gas flaring. It can be argued that a government has the power, as the supervisor of public good, to control how the owner of associated or produced gas may or may not use it, so as not to waste the resource and also endanger the environment.[121]

C. The *Petroleum (Amendment) Decree* No.16, 1973 ("Decree No. 16"),[122] was promulgated to amend paragraph 35(b) of schedule 1 to the *Petroleum Act*.[123] Under the amended provision, natural gas can be given special treatment by the Minister if he considers it to be in the *public interest*. The terms and conditions which the Minister can impose on a license or lease include: the right of the government to take associated gas free of cost *at the flare* or at an agreed cost and without payment of royalty; an obligation on the lessee to obtain the approval of the government as to the price at which the natural

[118] *Ibid*.; *supra* note 4 at 181.
[119] *Re-injection Act*, *supra* note 115, s. 3(1) -(2).
[120] *Supra* note 63.
[121] In this connection, Prof. Okagbue argues that one must distinguish between an exercise of Government regulatory rights and its exercise of proprietary rights; that the *Re-injection Act*, *supra* note 115, can be seen in the context of a regulatory directive given by the government in the exercise of its power to control a wasting and finite resource. See Isabella Okagbue, "The Law and Development of Natural Gas in Nigeria", (1985) Nigeria Institute of Advanced Legal Studies, Occasional Paper No. 9, 5 at 11 [Okagbue]. See also Chukwuemerie, *supra* note 17 at 18.
[122] *Supra* note 17.
[123] *Ibid.*

gas it produces (and not taken by the government) is sold and a requirement that the lessee must pay a royalty on natural gas produced and sold.[124]

The view has been expressed that this provision reiterates the Federal government's absolute ownership right over all the natural gas in the leased area leaving the lessee with a mere right to use some quantities of gas discovered in the conduct of petroleum operations while also accounting for the remainder.[125] Another view is that the lessee has the exclusive right within the leased area to win, store, carry away, transport, export, or otherwise treat petroleum (which includes crude oil and natural gas) discovered in or under the leased area, subject to the provisions of paragraph 35 of schedule 1 of the *Petroleum Act*.[126] In other words, that the lessee, and not the Federal government has absolute ownership right over all the natural gas in the leased area.[127] With respect, the former view is not easily supportable, as will be shown in the following paragraphs.

A close examination of the provisions of paragraph 35(b) *vis á vis* other provisions of the *Petroleum Act*[128] reveals that the ownership of all the natural gas in the leased area continues to vest in the lessee. It is instructive to note that Decree No.16 amended paragraph 35, schedule 1 of the *Petroleum Act* without a concomitant amendment of section 2(1)(c) or paragraph 11, schedule 1 of the Act.[129] These sections provide for the exclusive right of a lessee to the petroleum in or under the leased area, nor

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[124] Emphasis mine.
[125] See Okagbue, *supra* note 121. She further posits that if the lessee owns natural gas at all, it will only be the gas that it has won or extracted from the ground, on the contention that a mining lease, as a concession, only amounts to a *profit a prendre*. Okagbue, *supra* note 121. The Federal Government also subscribes to this view. See Chukwuemerie, *supra* note 17 at 15-16; Olisa, *supra* note 11 at 280; & Momodu, Legal Aspect of Ownership, *supra* note 98 at 271.
[126] *Supra* note 17.
[127] The oil companies predictably support this view. For other supporters, see *supra* note 16 at 216, Momodu, Legal Aspect of Ownership, *supra* note 98 at 271; Chukwuemerie, *supra* note 17 at 15-16; & *supra* note 5 at 224-225.
[128] *Supra* note 17.
[129] *Ibid*.

section 15, which defines petroleum as including all the natural gas in the strata.[130] This oversight, as will be seen, is one of the reasons why this debate still lingers today. [131]

First, it is necessary to note that paragraph 35(b) provides that the Minister may only impose the special terms and conditions "if he considers it to be in public interest". Until and unless he thinks fit to do so, whatever effects the terms and conditions are supposed to have do not arise. Even if such terms vests ownership rights in the Federal government, they are limited to exceptional cases where public interest may be affected. Therefore, the general position remains as it was in 1969. Even if paragraph 35(b) indeed changed or changes that *status quo*, it is only with respect to those exceptional or special cases. It is an exception rather than the rule.[132]

Second, the provision in paragraph 35(b)(i) speaks specifically of associated gas at the flare distinct from non-associated natural gas and non-flared gas. The provision does not support the view that the government has an absolute right to take delivery of all non-associated gas or associated gas.[133] The government is only entitled to take gas at

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[130] *Ibid*.

[131] Curiously enough, Reg. 61(1)(b) of the *Petroleum Regulations*, *supra* note 63, was amended in 1995 (Statutory Instrument No. 8 of 1995) to delete the part that referred to gas being "sold and actually delivered to the NNOC (NNPC) under a gas sale contract". This amendment might have been because the Federal Government realized that the NNPC cannot buy gas from the licensee or lessee under" a gas sale contract", if the gas, indeed, belonged to the Federal Government and not the lessee. The Federal Government would not want to be seen as making a rule permitting it to buy that which it already owned, if it actually owned discovered or associated gas. See Chukwuemerie, *supra* note 17 at 15-16.

[132] See Chukwuemerie, *ibid.* at 16. He further argues that the paragraph is only a regulation - a statutory instrument deriving authority from the *Petroleum Act*. Since the *Petroleum Act* firmly vests ownership of such gas in the licensee or lessee, a statutory instrument or regulation made under the Act can hardly alter that. Apparently realizing this, it is provided in para. 35 itself that the special terms and conditions to be imposed by the Minister shall be such as are "not inconsistent with this Act". "This Act" in the context means or includes ss. 2(1) (c), 11 & 15 of the *Petroleum Act*, *supra* note 17. He submits that for the paragraph to have any effect, it has to be put in the main body of the Act.

[133] With the exception of the natural gas which was already committed by the lessee as part of a project approved by the government. See a 1971 Federal Government Agreement with Oil Producing Companies, para. 10. This Agreement formed the basis of Decree No. 16 of 1973. See Momodu, Legal Aspect of Ownership, *supra* note 98 at 270.

the flare.[134] This leaves natural gas, which is not taken by the government at the flare, available for the lessee's use and ownership, provided that certain terms and conditions are met.

This provision does not violate the lessee's exclusive right over the natural gas since the lessee may exercise its rights to store, carry away, transport, export or otherwise treat all its petroleum (including natural gas in its free or associated form),[135] without flaring the gas. If the lessee does this, there will be no natural gas for the government to take at the flare thereby rendering Decree No.16 irrelevant.[136]

While the requirement of obtaining "the approval of the Federal government" as to the price at which to sell natural gas under paragraph 35(b)(ii) seems like an erosion of the lessee's right,[137] it is arguable that this requirement is only meant to ensure that natural gas coming out of Nigeria is not sold below or above a particular prevalent price at any material time. It is, in that case, not necessarily an assertion of ownership, but a price control regulation.

Further, while the requirement for payment of royalty on any natural gas produced and sold under paragraph 35(b)(iii) seems like a serious derogation from the lessee's ownership of the natural gas, and an assertion of ownership on the part of the Federal government, this is really not the case. It is just like the royalty payable on crude

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[134] *Petroleum Regulations*, *supra* note 63, Reg. 61(1)(b) provides for payment by the licensee or lessee to the Minister within a month after the end of each quarter, or otherwise as the Minister may direct, "royalty at a rate per centum of the price received by a licensee or lessee in the relevant area and sold and but does not include any *flare or waste gas* appropriated by the government of the federation for its own use or for any purpose approved by it". When para. 35(b)(i) is read together with Regulation 61(1) (b) of the *Petroleum Regulations*, *supra* note 63, it seem rather clear that the Federal Government can only take "any flare or waste gas" i.e. gas can only be taken free of cost at the flare and not before.

[135] As provided for in the *Petroleum Act*, *supra* note 17, s. 2(1) (c) & sch. 1, para. 11.

[136] See Momodu, Legal Aspect of Ownership, *supra* note 98 at 271.

[137] A lessee can hardly be required to seek approval on the price at which to sell his own property.

oil, which does not necessarily determine ownership. It can be seen as a royalty or rent for the grant of the lease, but one which is not all paid at the time of grant.[138]

It is submitted that if paragraph 35(b) was intended to vest ownership of discovered or associated gas in the Federal government, it fails. In order to transfer ownership from the lessee to the government, it is not sufficient to expunge a few words. It is clear that a provision in clear and compelling language is required.

2.3 Compliance with Laws Clause

The ability of the government to amend the Petroleum Act and enact laws to affect the lessee's right to all the natural gas within the area of grant presupposes that there is a Compliance with Law Clause. This is indeed the case. Clause 2 of forms C (OPL) and D (OML) of the *Petroleum Regulations* respectively anticipate that the license or lease shall be subject to the provisions of the *Petroleum Act* and related regulations in force or which may come into force during the continuance of the OPL or OML. When read in the context of the Minister's general powers to unilaterally alter or make regulations under section 9 of the *Petroleum Act*, this confirms that new or amended regulatory provisions (which may alter existing obligations or impose new obligations) are binding on existing lessees, with or without securing their consent. In practice, the Minister makes prior consultation with the industry stakeholders before decisions to amend regulations, which may affect the lessees, are made.[139]

[138] See Chukwuemerie, *supra* note 17 at 16.
[139] See *supra* note 5 at 121.

This clause is similar to that found in Alberta Crown Leases. Nigeria, like Alberta is considered "proven" so that the clause has not deterred prospective investors.[140] The country has an established record to build confidence that the government will not abuse its power to enact any bad faith or expropriatory laws. Just like Alberta, this power has only been exercised to introduce minor fees, rents and royalties changes.[141]

It is submitted that the Federal government can use its power under section 9 of the *Petroleum Act*[142] and the compliance with law clause to re-vest natural gas rights in itself. This is no doubt true as a matter of law, but this does not affect the legal position today and this should only be done after putting in place a structure to ensure fairness to the lessees.

2.4 Assessment

There is no provision in the existing legislation which clearly establishes that all the natural gas in leased area is owned by the Federal government. Indeed, it's the other way round. The legislation says that natural gas rights are in the lessee and no subsequent Act changes that conclusion. Paragraph 35 of schedule 1, *Petroleum Act*[143] has not in any way established such right. All the paragraph has done is to create the right of government to take associated gas free of charge at the flare. Prior to the flare, the government cannot treat the natural gas as its own.[144]

As long as the definition of petroleum remains as it presently is in the *Petroleum Act*, the lessee's right of ownership to all the discovered and extracted natural gas in the

[140] As it is, the level of investment in the petroleum industry is very high and the industry is the number one revenue earner for the country. See *supra* note 3 at 2.
[141] See *supra* note 5 at 121.
[142] *Supra* note 17.
[143] *Supra* note 17.
[144] See Momodu, Legal Aspect of Ownership, *supra* note 98 at 271; Okagbue, *supra* note 121; *supra* note 16 at 216; Chukwuemerie, *supra* note 17 at 15-16.

leased area cannot be violated. Its right of ownership is only subject to governmental control where it decides to flare[145] and to governmental approved pricing where it desires to sell the gas.[146] The lessee is free to use any quantity for its own use but flared gas can be taken by the government at the flare free of cost.[147] However, cost of delivery at a point beyond the flare point must be met by the government.[148]

An interesting point to note is that paragraph 35 of schedule 1, *Petroleum Act*[149] and the *Re-injection Act* apply to "natural gas produced with crude oil", commonly known as associated gas. The enactments do not address the issue of non-associated natural gas within the leased areas. From the terms of the OMLs normally granted, it can be argued that non-associated natural gas (like associated gas) within the leased areas is the property of the lessee. The terms of grant give the lessee such wide powers and rights that one cannot fail to reach the conclusion that the ownership right in the natural gas in strata originally vested in the Federal government by the *Petroleum Act*[150] and the 1999 constitution,[151] has been transferred to the lessee upon production. The lessee may therefore embark on deliberate exploration and exploitation of non-associated gas just as it does with crude oil in the leased area.[152]

What clearly emerges from this discussion is that, with the present state of the law, Nigeria does not own discovered, associated or produced gas in the OMLs it has granted. The country's position is adversely affected by this arrangement, as many of its

[145] As provided in the *Re-injection Act*, *supra* note 115.
[146] See *Petroleum Act*, *supra* note 17, sch. 1, para. 35 (1) (b) (ii).
[147] The view has been expressed that "technically, ownership in gas which has been 'won' from the ground by the lessee passes to the said producer and any subsequent 'taking' by the government at the flare should give rise to compensation". See Okagbue, *supra* note 121 at 11.
[148] As stated in the 1971 Federal Government Agreement with Oil Producing Companies, *supra* note 133.
[149] *Supra* note 17.
[150] *Supra* note 17, s. 1(2).
[151] *Supra* note 22.
[152] See Momodu, Legal Aspect of Ownership, *supra* note 98 at 273.

natural gas resources are covered and affected by these OMLs. But for the joint venture arrangements,[153] Nigeria would have no interest in them. Even then, this interest is held through the very expensive practice of contributing its percentage of all expenses of the operator's cash calls, which has constituted a serious source of expending its lean resources.

Further, lessees are not really keen on harnessing natural gas because its exploitation in Nigeria is far less profitable than that of crude oil.[154] It would therefore be better for the country to make provisions re-vesting total ownership of the gas in itself, so that it can find interested operators to exploit the gas or it could enter into completely different arrangements with the present lessee with respect to natural gas. This action would avoid the present situation, where the joint venture arrangement, expressly or impliedly, governs everything.

3 CONSERVATION OF NATURAL GAS

This section will examine the legal and regulatory framework for the conservation of natural gas in the country.

3.1 Pre-Conservation Era

Unlike in Alberta where natural gas conservation is highly developed, the move towards natural gas conservation in Nigeria is fairly recent. Although provisions were made for conservation in the *Petroleum Act*, when it was enacted in 1969, they were mainly in respect of crude oil. It was not until the enactment of the *Re-injection Act* in

[153] See for example the recent joint venture arrangement for the utilization of associated gas that the NNPC has with Mobil Nigeria- Oso-NGL Gas Recovery Project, which is divided in the ratio of 60:40 in favour of NNPC and Mobil respectively. See Chukwuemerie, *supra* note 17 at 19.
[154] See Omorogbe, Oil and Gas Law, *supra* note 23 at 56.

1979 that natural gas conservation became a part of the Nigerian lexicon. As the name shows, the conservation provisions in the *Re-injection Act* are only in respect of associated gas.

Before the *Re-injection Act* was enacted, natural gas was blatantly flared by lessees who were more interested in harnessing crude oil rather than natural gas that was produced with it.[155] Gas flaring is a sad metaphor for a profligate country that eats her chickens and the eggs and yet expects more eggs in future.[156] While Alberta now earns huge foreign revenue from selling its gas, the bulk of Nigeria's natural gas resource is being flared. Gas flaring has obvious disadvantages - gas flared is permanently lost and is therefore wasted[157] and the environment is extremely polluted by it.[158] The picture in Appendix I[159] depict succinctly the image of natural gas being flared from an oil well in Nigeria.

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[155] According to Omorogbe, gas flaring is an extremely wasteful and environmentally harmful practice, but the capacity for utilization of associated gas and financial requirements have influenced the decision on whether or not to flare. Omorogbe, Law and Investor Protection *supra* note 4 at 181. See also *supra* note 17 at 160-162; Climate Justice Programme and Environmental Rights, "Gas Flaring in Nigeria: A Human Rights, Environmental and Economic Monstrosity" (June 2005) online: Climate Justice <http://www.climatelaw.org/media/gas.flaring/report/section4> [Climate Justice].

[156] Akanimo Sampson, "Gas Flaring, Nigerian Govt Under Pressure" *Scoop* (16 December 2008), online: <http://www.scoop.co.nz/stories/WO0812/S00359.htm>.

[157] The quantity of gas that is flared is enough to meet Nigeria's energy needs and leave a healthy balance for export. It is more saddening because the biggest need for natural gas is in Nigeria. The country is in the grip of a power generation crisis and the gas that is being burned could go a long way towards providing the electricity the country desperately needs in order to develop its economy. According to Ayo Odusola, an economist from UN Environmental Programme in Nigeria, "It is an anomaly that a country that flares so much gas is lacking adequate electricity and other domestic fuels like cooking gas". See Abiose Adelaja, "Nigeria Gas Flaring Cap in Doubt" *Science Development* (20 November 2007), online: <http://www.scidev.net/en/climate-change-and-energy/fossil-fuels/news/nigeria-gas-flaring-cap-in-doubt.html>; *ibid*.

[158] Studies have shown that the ecology of areas surrounding flares is negatively affected by such flares. Also, flaring is responsible for causing chronic health problems among people who live in the Delta of Nigeria See Yinka Omorogbe, "Legal Framework for the Production of Petroleum in Nigeria" (1987) 5 J. Energy, Nat'l Res. L., 273 at 284 [Omorogbe, Legal Framework]. See also Augustine O. Isichie & William W. Sanford, "The Effects of Waste Gas Flares on the Surrounding Vegetation in Southeast Nigeria", (1976) 13:1 J. Applied Ecology, 177. See also Andrew Walker, "Nigeria's Gas Profits 'Up in Smoke'" *BBC News* (13 January 2009), online: BBC News <http://news.bbc.co.uk/2/hi/africa/7820384.stm> [Walker].

[159] Ini Ekott, "Barkindo Seeks Extension to Gas Flaring Deadline", *Timbuktu Media* (31 August 2009), online: 234next.com <http://234next.com/csp/cms/sites/Next/News/National/5451134-147/story.csp>.

The issuance of a blanket license or lease that covers the exploration and exploitation of both crude oil and natural gas is a major reason why the lessees can do as they wish with associated natural gas.[160] Unlike in Alberta, where the battle to conserve natural gas was long and drawn out, no such battle was waged in Nigeria before the enactment of the *Re-injection Act*. It was the recognition of the potential of the natural gas industry as a revenue earner rather than any conservation or pollution concern that necessitated the enactment of the Act.[161] Nevertheless, the battle that was not fought before its enactment started after its enactment and is still being fought today, as natural gas is still not being rationally developed as envisaged by the Act.[162]

In Alberta, conservation of natural gas means adopting measures such as: well spacing and unitization requirements; provisions for common carriers, processors, and purchasers to avoid indirect monopolization; prescription of maximum rate of production; the limitation or distribution of the amount of gas that may be produced from a pool or part of a pool through rateable take regulations; and the prevention of natural gas waste. These measures, save for the prevention of gas waste, may not be necessary in Nigeria.[163]

In Nigeria, natural gas is initially owned by the Federal government and not private individuals. By granting concessions that includes large areas, the government reduces the potential for competitive, wasteful over-drilling and production that occurred

[160] Compare with the situation in Alberta where separate licenses and lease are issued in respect of crude oil and natural gas. See Omorogbe, Legal Framework, *supra* note 158 at 284; MMA, *supra* note 106, s. 80(2)(a).

[161] Nigeria's overall policy regarding the development of its natural resources is to maximize returns and earnings. See Omorogbe, Legal Framework, *supra* note 158 at 254; Oghogho Makinde, Sesi Fasinro, & Lanre Williams, "Oil Regulation: Nigeria" (2004) Global Competition Review at 45.

[162] Until recently, Nigeria was regarded as the world's biggest flarer of gas in absolute and proportionate terms. See Barbara Lewis, "Gas Flaring Makes Less Economic Sense" *Edmonton Journal* (12 July 2007) E3 [Lewis]; Climate Justice, *supra* note 155.

[163] Although these measures are not necessary, some of them do exist. The Petroleum Regulation, *supra* note 63, Reg. 48 provides unitization and joint development of reservoirs. Also the *Oil Pipelines Act*, *supra* note 37, s. 18 makes provision for common carriers so as to optimally utilize the natural gas resource of the country. Notwithstanding these provisions, there is no evidence of its application or enforcement.

in Alberta's pre-conservation era and that necessitated some of the above measures. Nonetheless, the government should have a legal mechanism in place to ensure that its lessees are following petroleum engineering principles for sound conservation of gas. Evidence however suggests that both the government and the lessees have preferred immediate cash flows from rapid production of crude oil, resulting in suboptimal recovery rate and waste of natural gas. Weaver has described this as "wasteful development".[164]

3.2 Conservation Era

Today, provisions on natural gas conservation in the *Petroleum Act* and related regulations are few and imprecisely drafted. For example, the *Petroleum Act* empowers the Minister to make regulations for the conservation of petroleum resources and the prevention of pollution of watercourses and the atmosphere.[165] This section vests discretionary powers in the Minister, which he may choose not to exercise especially in cases that involve the NNPC. Further, the pollution prevention measures to be taken by the Minister, through the Department, do not require the approval of the environmental regulatory agency, the Federal Environmental Protection Agency ("FEPA").[166] This is unlike the case in Alberta where the approval of the Minister of the Environment is required before the introduction of such measures, coupled with the Clean Air Strategic Alliance's substantial input in the formulation of such measures.

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[164] Weaver, *supra* note 83.
[165] *Supra* note 17, s. 9 (b)(ii) and (iii).
[166] FEPA is charged with the responsibility of formulating environmental standards and monitoring compliance with such standards. It also administers the *Environmental Impact Assessment Decree* No. 86 of 1992. FEPA's enabling statutes are the *Federal Environmental Protection Agency Act*, LFN 2004, c. F10 and the *Federal Environmental Protection Agency (Amendment) Decree* No. 59 of 1992.

In addition, the *Petroleum Regulations*,[167] which provide the main framework for regulating oil and gas production, only has three paragraphs specific to conservation. Regulation 39 requires a lessee to use *approved methods and practices acceptable to the Department* for the production of crude oil and natural gas; Regulation 25 requires a lessee to *adopt all practicable precautions*, including the provision of *up-to-date equipment* to prevent pollution and where such pollution has occurred to *take prompt steps to control same* and if possible end it and Regulation 44 empowers the Department to give directions which it considers necessary to ensure proper exploitation of petroleum and to *encourage good conservation practices* in any licensed or leased land.[168]

These provisions are not very detailed. They do not state the specific conservation measures that the lessees are required to take. Also, it is obvious that the Department has a wide discretionary power with respect to conservation of the country's petroleum resources. The Department may decide to establish different standards for different lessee or to set no standards at all. Considering the limited human and material resources at its disposal, setting of standards covering all areas of oil operations, may be virtually impossible.[169] Omorogbe notes that the fact that nothing concrete is said on conservation stems from the fact that Nigeria has not practiced any conservation policies in the management of its resources and production has followed the great demands of the economy.[170]

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[167] *Supra* note 63.
[168] Emphasis mine.
[169] See David Osigbemhe Iyalomhe, *Environmental Regulation of the Oil and Gas Industry in Nigeria: Lessons from Alberta's Experience* (LL.M. Thesis, University of Alberta, Faculty of Law, 1998) [Unpublished] at 48 [Iyalomhe].
[170] Omorogbe, Legal Framework, *supra* note 158 at 275.

While the above provisions apply to both crude oil and natural gas, only two provisions can be said to be related to natural gas conservation. The first provision is Regulation 43 of the *Petroleum Regulations*,[171] which provides that no later than five years after the commencement of production from the relevant area, a lessee should submit to the Minister any feasibility study, programme or proposals that it may have for the utilization of any natural gas discovered in the relevant area, whether associated with oil or not. This provision does not impose any duty on the lessee, it requires the submission of a feasibility study if it has one.[172]

The second provision is paragraph 35 (b) (i) of the first schedule to the *Petroleum Act*,[173] which empowers the government to take natural gas at the flare. The taking of gas at the flare is a very effective tool for natural gas conservation, as it would save gas that would otherwise be flared. Unfortunately, the government has chosen to use this provision to assert its ownership right to the produced gas, rather than to use it as a conservation tool. In practice, it is doubtful that the government has ever taken any gas at the flare.

3.3 Conservation Measures

The *Re-injection Act*, which is essentially the only natural gas conservation legislation in Nigeria, provides for measures designed to stop or reduce considerably, the

[171] *Supra* note 63.
[172] This is because of the use of the phrase "may" and not "must". Legally, the word "may" connote a discretion. Thus the duty of "shall submit to the Minister", in the opening part of the provision only arises if indeed the lessee decides to have and does have "any feasibility study". For "may" to be as "must" in Nigerian law, an extremely clear contextual need (for the working of justice) must be shown. See *PIPDC Ltd. v. Phillip Eblota and 5 ors.* (2001) FWLR (Pt 64) 374. In the provision under consideration, no such need can be shown. See Chukwuemerie, *supra* note 17 at 14.
[173] *Supra* note 17.

flaring of gas produced in association with crude oil.[174] Re-injection, which is also provided for in Alberta's *Oil and Gas Conservation Act* ("OGCA"),[175] conserves the natural gas until it can be produced commercially. At the same time it is a means of enhancing reservoir energy which aids recovery of the crude oil located within the well.[176]

The *Re-injection Act* transformed Regulation 43 into a mandatory provision.[177] It provides that whether or not a licensee or lessee has submitted a scheme for the utilization of associated gas as required by Regulation 43, every company producing oil or gas in Nigeria must submit to the Minister, no later than 1 April 1980, a preliminary programme, and no later than 1 October 1980, a detailed programme, for the viable utilization of all associated gas, and projects to re-inject all associated gas produced which was not currently being utilized.[178]

By section 3, no company was to flare associated gas after 1 January 1984 without the written permission of the Minister. This deadline was shifted twice, to 1 April 1984, and then to 1 January 1985.[179] The penalty for flaring was the stringent, if not unrealistic, punishment of forfeiture of all concessions in the field where the offence was committed and the forfeiture of all or any entitlement.[180] Although the penalties for non-

[174] It also provides for measure to control atmospheric pollution. See *supra* note 11 at 277.
[175] R.S.A. 2000, c. O-6.
[176] *Ibid*. The fact is that, in Nigeria, when associated gas is found, only three options exist: to utilize it, to re-inject it into the reservoir, or to flare it. The utilization of associated gas depends on the capacity of the domestic natural gas market and on the economics of utilization vis a vis gas flaring. On the whole, the costs involved in associated gas utilization have been estimated to be ten times higher than for non-associated gas. Re-injection is an environmentally friendly option which also enhances reservoir energy, but which is significantly more expensive than flaring. Flaring is thus the cheapest option and is therefore mostly utilized. See Omorogbe, Law and Investor Protection, *supra* note 27 at 181.
[177] *Petroleum Regulation*, *supra* note 63.
[178] *Re-injection Act*, *supra* note 115, ss. 1- 2.
[179] *Ibid*.
[180] The withheld entitlement is used to offset the cost of completion or implementation of a desirable re-injection scheme, or the repair or restoration of any reservoir in the field in accordance with good oil field

compliance were stringent, it was difficult for oil companies to comply with the provisions of the Act.

Two main problems hindered compliance. First was the issue of cost. Since the bulk of Nigeria's crude oil is produced under joint ventures, where the Federal government, through the NNPC, is the majority partner, NNPC had to share in the financial burden of putting in place gas re-injection facilities. Since it was unable to meet this obligation because of the nation's shortage of foreign reserves, there was therefore no alternative but to continue to flare the gas. Second, most oil companies showed lack of enthusiasm and commitment because hardly any infrastructure existed to gather and process the associated gas produced.[181] According to Khan, the *Re-injection Act* was the least appropriate way of checking the increasing levels of gas flaring, since it penalized oil companies' actions without offering alternatives.[182] Without any viable gas utilization proposal of its own, the government could not credibly enforce stringent anti-flaring legislation.[183]

The *Associated Gas Re-Injection (Amendment) Act, 1985*[184] was enacted to ease the stringent penalty provisions of the *Re-injection Act*. This Act amended section 3 by adding a new subsection which provided that if, after 1 January 1984, the Minister is satisfied that re-injection or utilization of the produced gas is not appropriate or feasible, he is to issue a certificate which will specify the terms and conditions for the continued

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practice. Unfortunately, neither the *Re-injection Act*, *ibid*. nor the *Petroleum Act*, *supra* note 17, provides a definition of "entitlement", leaving one to wonder about the kind of entitlement that would be forfeited.

[181] See Omorogbe, Oil and Gas Law, *supra* note 23 at 59; *supra* note 3 at 162.

[182] *Supra* note 3 at 162.

[183] *Ibid*.

[184] The provisions of the said amendment have since been incorporated into the provisions of the principal Act, the *Re-injection Act*, *supra* note 115.

flaring of such gas.[185] The certificate is to be issued, only where any one or more of the conditions specified in the *Associated Gas Re-injection (Continued Flaring of Gas) Regulations* ("*Re-injection Regulations*"),[186] 1984 is satisfied, or where the Minister so orders.[187] The conditions are as follows:

> (a) where more than 75% of the produced gas is effectively utilized or conserved;
> (b) where the produced gas contains more than 15% impurities, such as carbon dioxide, which render the gas unsuitable for industrial purposes;
> (c) where an on-going utilization programme is interrupted by equipment failure. Provided that such failures are not considered too frequent by the Minister and the period of any one interruption is not more than 3 months;
> (d) where the ratio of the volume of gas produced per day to the distance of the field from the nearest gas line or possible utilization point is less than 50,000SCF/KM. Provided that the gas-to-oil ratio of the field is less than 3,500 SCF/bbl, and that it is not technically advisable to re-inject gas in that field.[188]

When the field is held to qualify for the continuation of gas flaring, a prescribed amount is required to be paid before the continuation certificate is issued.[189] The prescribed sum, payment of which is not strictly enforced,[190] is a paltry ₦10.00 (11 American cents at 1998 exchange rate levels) per 1,000 standard cubic feet of gas flared.[191]

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[185] *Ibid.*, s.3(2).
[186] Statutory Instrument 43 of 1984, s.1.
[187] *Ibid*., paras. (e).
[188] *Ibid*., paras. (a)-(d).
[189] The payment is required to be made in the same manner and subject to the same procedure as the payment of royalties to the Federal Government by oil producing companies. *Re-injection Act*, s*upra* note 115, s. 3(2)(b).
[190] Only the operators of the joint ventures pay this sum, and not the NNPC, despite the fact that both are joint venture partners, who are obligated to share expenses and profits in accordance with their participation interest. As a result, most of the operators only pay their share of the sum and the Department does not enforce the collection of the balance against the NNPC. See Omorogbe, Oil and Gas Law, *supra* note 23 at 60.
[191] See Federal Government of Nigeria, "1998 Financial Budget" Federal Government of Nigeria Official Gazette (6 January 1998). The amount that was first prescribed was ₦0.05 (2.5 U.S. cents at 1987 exchange rate levels). It was then increased to ₦10.00 in January 1998. When the last civilian government announced

These conditions are similar to some of the provisions in Alberta's Directive 060: *Upstream Petroleum Flaring, Incinerating, and Venting* [Directive 060].[192] Directive 060 also forbids gas flaring, but recognizes that it is impossible to totally eliminate flaring. Therefore gas is permitted to be flared for purposes of testing the well to assess its capability and to determine the appropriate gathering and processing facility required to best handle the well's production; where it is not economically or technically practical to conserve such gas; or where there is an operational upset, such as equipment failure.

But unlike the *Re-injection Act*[193] and the Re-injection Regulation,[194] when gas flaring is permitted under the Directive, the operators are required to reduce the levels of volumes flared according to specified flare requirements. They are also required to design and operate flares with a level of combustion efficiency that controls odour and visible smoke emissions. In order to achieve goals of this type, more is required of the Nigerian legislation, than the existing skeletal provisions. If there is to be a reduction in gas flaring, a more in-depth regulatory instrument like Directive 060, which addresses a wide variety of gas conservation issues, is required.

At the time they came into force, the 1985 Amendment Act and the *Re-injection Regulations* had the cumulative effect of exempting 86 out of 155 oil fields and the companies found it cheaper to flare rather than inject.[195] Today, natural gas is still being

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its intention to increase the fine to 22 American cents per 1,000 cubic feet of gas flared, the operators resisted this move because the proposed rate of fine would have cost them $100 million in flaring penalty. See Omorogbe, *ibid*.

[192] See ERCB, D60-2006, s. 2, online: ERCB <http://www.ercb.ca/docs/documents/directives/Directive060.pdf> [Directive 060].

[193] S*upra* note 115, s. 3(2).

[194] *Supra* note 186.

[195] In 1985, Gulf Oil (now Chevron) stated that while gas flaring would cost the company $1 million, the cost of switching from water to gas re-injection would cost $56 million. The economics for re-injection was therefore not acceptable to most oil companies. See *supra* note 3 at 162; Omorogbe, Oil and Gas Law, *supra* note 23 at 59.

flagrantly flared, just as it always has been.[196] These provisions have therefore failed in reducing gas flaring.

As a result of local and international outcry against egregious gas flaring,[197] the Federal Executive Government directed that oil companies must stop gas flaring by 31 December 2008.[198] The Federal Legislative Government knew that the Executive would not follow through with this directive and therefore took matters into its hands by initiating two Bills - one to amend the *Re-injection Act*,[199] and the other, to prohibit and punish gas flaring.

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[196] According to NNPC, about 40% of Nigeria's associated gas is still being flared. NNPC, "Gas Investment Opportunities", online: NNPC <http://www.nnpcgroup.com/nigeriagas.htm>. The accuracy of this figure has however been contradicted by others. Mr. Billy Agha, the Head of Gas at the Department of Petroleum Resources, recently stated that about 80% of associated gas is still being flared. See Estelle Shirbon, "Nigeria Threatens Stiff Penalty for Gas Flaring" *Reuters* (27 November 2007), online: Reuters <http://www.reuters.com/article/rbssEnergyNews/idUSL2772789220071127>.
[Reuters]. The World Bank also states that more than 55% of Nigeria's associated gas is still being flared and Nigeria currently accounts for 12.5% of the world's gas flaring. See Energy Information Administration [EIA], "Country Analysis Brief: Nigeria" 2009, online: EIA <http://www.eia.doe.gov/cabs/Nigeria/Background.html> at 6.

[197] On the average, about 1000 standard cubic feet (scf) of gas is produced in Nigeria with every barrel of oil, therefore, with the oil production of some 2.5 million barrels per day, about 2.5 billion scf of associated gas is produced and flared everyday. This estimate places Nigeria as one of the leading gas flarer in the world. See Walker, *supra* note 158. Climate Justice, *supra* note 155; Sampson, *supra* note 156; EIA, "Nigeria: Natural Gas" 2009, online: EIA <http://www.eia.doe.gov/emeu/cabs/Nigeria/NaturalGas.html>.

[198] See, Sebastine Obasi & Dike Onwuamaeze, "Gas Flaring to End Soon" *Newswatch* (12 May 2008), online: Newswatch <http://www.newswatchngr.com/editorial/allaccess/business/biz07.htm>. As it is, this deadline, just like earlier deadlines, has passed and gas is still being flared. Even as the December 2008 deadline was being announced, Shell and other joint venture companies announced that they would not be able to meet the deadline, citing lack of access to sites due to continued unrest in the Niger Delta region and a shortage of government-owned pipelines to transport the harvested gas. Both the federal government and these companies have been blaming one another for the continued flaring. The companies blame the government for delays in eliminating flares, arguing that it has failed to provide its share of the cash call funding needed to build gas gathering plants and pipelines that would allow them to make use of the gas. Also that the government can't guarantee oil workers' security in a region patrolled by armed gangs who kidnap oil company workers. While the Departmnet disputes this and accuse the companies of making use of cash call money to invest in new projects to extract gas separately from crude instead of solving the flaring problem. See Reuters, *supra* note 196; Hamisu Muhammad & Mohammed Shosanya, "Gas Flaring: Multinationals Defy FG" *Daily Trust* (1 January 2009), online: Daily Trust <http://www.dailytrust.com/index.php?option=com_content&task=view&id=1986&Itemid=82>; Walker, *supra* note 143; Festus Akanbi, "FG slams tough sanctions on gas flaring firm" *Thisday Online* (30 March 2008), online: Thisday Online <http://www.thisdayonline.com/nview.php?id=107262> [Akanbi].

[199] *Supra* note 115.

The *Associated Gas Re-Injection (Amendment) Bill*, 2008[200] [*Re-injection (Amendment) Bill*], seeks to extend the deadline for gas flaring from 1 January 1985 to 31 December 2008[201] and to also specify a fine of 410.00 Nigerian Naira, (about $3.00 at 2008 exchange rate levels) for every standard cubic feet of gas flared, where permission is granted by the Minister to so continue.[202] It is submitted that if this Bill, which is still being considered by the House of Representative,[203] is to be effective, it will require more than just the imposition of deadlines and fines.

The *Gas Flaring (Prohibition and Punishment) Bill* 2009 [*Gas Flaring Bill*],[204] which is presently being before the House of Representative for deliberation, is much more encompassing than the former. Just like the *Re-injection (Amendment) Bill*, it seeks to prohibit the continued flaring gas after a fixed date.[205] But unlike the *Re-injection (Amendment) Bill*, the *Gas Flaring Bill* applies to both associated and non-associated gas.[206] The penalty for continued flaring after this date is the payment of a fine which shall be equal to the cost of gas at the international market.[207] This is in stark contrast to the fixed penalty of ₦410 prescribed in the *Re-Injection (Amendment) Bill*.[208]

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[200] HB 112, C3091, online: National Assembly of Nigeria <http://www.nassnig.org/legislation.php?year=1999>.
[201] The *Re-injection Act*, *supra* note 115 provides for the current deadline.
[202] *Supra* note 200, ss. 2-3.
[203] The *Bill* passed second reading in the House of Representatives on 18 November 2008. It is presently before the Joint Committee on Gas and Justice for reconsideration. See House of Representatives, Federal Republic of Nigeria, Fourth Republic, 3rd National Assembly, Second Session, No. 46, Votes and Proceedings, 18 November, 2008 at 3.
[204] SB. 126, online: National Assembly of Nigeria <http://www.nassnig.org/senate/votes.php>.
[205] *Ibid*., clause 2. Clause 4 however seeks to give the Minister power to grant a permit to flare gas in cases of start-up, equipment failure, or shut down, for a period not more than 30 days. In such a case, the operator is liable to pay a fine which shall not be less than the cost of gas at the international market. Compare this with the provisions of the *Re-injection Regulations*, *supra*, note 186, which gave the operators a much wider lee-way to continue flaring.
[206] This will ensure that whenever non-associated gas is fully being developed, it is not flagrantly wasted.
[207] *Supra* note 204, clause 9.
[208] *Supra* note 200.

The *Gas Flaring Bill* revokes of the power of the Minister to grant a continuation certificate under the *Re-injection Act*.[209] It also recommends an amendment of Regulation 43 of the *Petroleum Regulations*[210] to the extent that it prescribes 5 years after the commencement of production as the period within which a lessee shall submit any feasibility study it may have for the utilization of natural gas.[211]

Also, the Bill mandates the Minister to make appropriate arrangements for the exercise of the Federal government's rights to take associated gas at the flare, as provided for in paragraph 35(b)(i), schedule 1 of the *Petroleum Act*.[212] It further provides that a lack of due exercise of such right shall not be ground for flaring such gas.[213] Thankfully, the government has realized the importance of exercising its right to take gas at the flare. This will ensure the conservation of gas that would otherwise be flared.

Further, the *Gas Flaring Bill* seeks to amend section 1 of the *Re-injection Act*[214] to the extent that:[215]

i. it stipulates 1 April 1980 as the deadline for submission of a preliminary programme for utilization scheme;
ii. it does not apply to industrial projects; and
iii. it vests the Minister with powers to issue continuation certificate.

The Bill prescribes that a lessee may re-inject the gas where it is not able to viably utilize it. Where it is unable to utilize or re-inject such gas, it is required to shut-in the

[209] *Supra* note 115.
[210] *Supra* note 63.
[211] *Supra* note 204, sch. 1, paras. 1 & 2(b). The Bill, in s. 2(1), instead provides that such programme, (now required to be comprehensive) must be submitted within three months of the commencement of the Act, in the case of existing license or lease, or at the time of applying for a license or lease, in the case of new applications. Such programme must be satisfactory to the Minister and be in consonance with the country's natural gas master plan and policies. This is not unlike the provisions in Alberta's Directive 060, *supra* note 192.
[212] *Supra* note 17; *Gas Flaring Bill*, *supra* note 204, clause 6 (2).
[213] *Supra* note 204, clause 6(2)(c).
[214] *Supra* note 115.
[215] *Supra* note 204, sch. 1, para. 2(a) (i-iii).

field.[216] Under Directive 060, until an approved gas conservation scheme is set up, an oil well with a high gas to oil ratio is also required to be shut-in.[217] But unlike the *Gas Flaring Bill*, the Directive prescribes other minor utilization alternatives like clustering and electricity generation for wells within the field, where it is impossible to re-inject or carry out other conservation scheme and where major utilization opportunities do not exist.[218]

Any lessee who flares gas after the fixed date commits an offence and is liable, upon conviction, to pay a fine equal to the cost of gas at the international market.[219] The provision for prosecution is commendable. The Alberta's Directive 060[220] and Directive 019, *Energy Resources Conservation Board Compliance Assurance – Enforcement* ("Directive 019")[221] also have provisions for prosecution when the Board believes a licensee has acted with demonstrated disregard. In the Directive, the severity of the non-compliance, which is assessed on a risk matrix, determines the enforcement action.

Hinging the fine to be paid on the international price of natural gas, though a brilliant idea when the price of gas is high might not seem so effective when the price falls drastically.[222] Also, the provision for increased fine might not help natural gas conservation efforts, because fines alone will not deter gas flaring.[223]

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[216] *Ibid*. clause 6 (2)(c)(iii).
[217] *Supra* note 192.
[218] *Ibid*., s. 2.6.
[219] *Supra* note 204, clause 9(1)(a).
[220] *Supra* note 192.
[221] ERCB, Directive 019, *Energy Resources Conservation Board Compliance Assurance – Enforcement*, online: ERCB <http://www.ercb.ca/docs/documents/directives/Directive019.pdf>.
[222] This is exactly what has happened. The price of gas, which had risen and remained stable for a long time, suddenly fell sharply. See Government of Alberta, News Release, "Lower Natural Gas Prices Drive Deficit Higher: Province to Further Reduce Costs of Government, Offset Shortfall by Withdrawal from Sustainability Fund" (26 August 2009) online: <http://www.alberta.ca/acn/200908/26755573D91FC-08C1-0886-A29AB3398F3C6303.html>.
[223] Indeed the Nigerian Minister of State for Petroleum, Mr Odein Ajumogobia (SAN) recently said to the media that although the Federal Government will certainly increase the penalty for gas flaring, that it is

The most far-reaching provision of the *Gas Flaring Bill* is the prescription that the Minister should be answerable to the Federal Legislature for failure, refusal, and neglect to shut down or implement the penalties provided in the Bill.[224] This provision might have been inserted to ensure that the Minister is free to carry out his functions without any interference from the Presidency.[225] A situation which suggests that the different arms of government are trying to circumvent one another, does not augur well for the country. Even if these Bills are passed into Law[226] and the Federal Executive, through the Department, does not or cannot ensure its implementation, gas flaring would still continue unabated.[227]

3.4 Enforcement Mechanisms

The two principal enactments that relate to the conservation of the country's mineral resources, the *Petroleum Act*[228] and the *Re-injection Act*,[229] do not make provision for an effective enforcement mechanism. The Acts vest the responsibility for enforcement in the Minister of Petroleum Resources, who carries out this responsibility through the Department. But in a situation where the country almost never has a

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however more interested in utilization and monetization of natural gas than penalties. See Akanbi, *supra* note 198.

[224] *Supra* note 204, clause 11.

[225] However, this provision might not be very effective given the situation in Nigeria where Ministers often refuse to answer the summons of the legislature with impunity.

[226] The *Gas Flaring Bill*, *supra* note 204, was passed by the Senate on 2 July 2009. It is presently before the House of Representative for deliberation and concurrence. The Bill, as passed by the Senate, is to take effect in 2011. See Senate of the Federal Republic of Nigeria, 6th National assembly, Third Session, No. 6, Votes and Proceedings, 2 July, 2009; Modestus Chukwulaka, "Senate Passes Gas Flaring Bill: Law to Take Effect in 2011" *Daily Sun* (4 July 2009), online: Daily Sun <http://www.sunnewsonline.com/webpages/features/newsonthehour/2009/july/04/newsbreak-04-07-2009-001.htm>. See *supra* note 203 for the current status of the *Re-injection (Amendment) Bill*. Once these Bills are passed in both the House of Representative and the Senate, which make up the Nigerian National Assembly, and the President gives his assent, they will become Acts of the National Assembly.

[227] This is going by the fate that has befallen earlier legislation in this regard.

[228] *Supra* notes 17.

[229] *Supra* note 115.

designated individual as the Minister, it is amply difficult to ensure compliance or carry out any serious enforcement. Also, the capability of the Department to enforce the provisions of the Acts is considerably reduced because of its relationship with the NNPC.[230] The Department derives its authority from the Ministry, which is closely aligned with the NNPC. [231]

Further, there are only few specific provisions on enforcement and related actions in the Acts.[232] For instance, schedule 1, paragraph 24(1)(a) of the *Petroleum Act*[233] provides that the Minister may revoke any OPL or OML for several reasons including failure of the lessee to conduct operations continuously and in a vigorous and businesslike manner and in accordance with good oilfield practices. Also, where the lessee has failed to comply with any legislative provision or regulation or is not fulfilling its obligations under the special conditions of the concession, the Minister may revoke its OPL or OML.[234] The Minister may however exercise his discretion and invite the lessee to provide an explanation for his non-compliance. If the Minister is satisfied with the explanation, he may ask the lessee to rectify the matter complained of within a specified period.[235]

The main feature of these provisions is the wide discretionary power that is bestowed on the Minister. The use of the discretionary approach in an industry as sophisticated as the petroleum industry is welcome. Regulatory officials inevitably

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[230] NNPC is a joint venture partner with the oil lessee who flares gas. It cannot be expected to effectively control itself or judge itself. See Raimi O. Ojikutu, "Sustainable Development, Oil Communities and the Oil Industry" (Paper presented to a Seminar on Oil and Gas Law, University of Lagos, 14-16 May 1996), at 11 [Unpublished].
[231] See the Federal Ministry of Energy Resources, above, section 2.1.2.
[232] *Petroleum Act*, *supra* note 17 and the *Re-injection Act*, *supra* note 115. The enforcement provisions in the *Re-injection Act*, were discussed above, section 3.3.
[233] *Supra* notes 17.
[234] *Ibid.* para. 24(1)(b), sch. 1.
[235] *Ibid*. para. 25-26, sch. 1.

practice considerable discretion in resolving legal ambiguities in order to achieve intended policy result.[236] There are, nevertheless, some difficulties with the use of wide discretion in Nigeria. The absence of infrastructural requirements, technological know-how, necessary man-power, inadequate funding, including the setting of different standards in the industry, hinder the regulatory agencies from performing their functions. An agency beset with all these difficulties can hardly be expected to exercise its discretion wisely and judiciously. In Alberta, the Board has been able to judiciously exercise its wide discretion because it is not beset with these difficulties.

Finally, an enforcement process, like that of Directives 019 and 060, should be set up. However before such process is introduced, it is necessary to seek input from the public and industry stakeholders. In Alberta, industry compliance with the enforcement process has been voluntary because they were developed after such consultations. It has been argued that voluntary systems are not very effective and that they require regulatory backing.[237] This is not necessarily true for all cases. There is a limit, beyond which rules and laws cannot match the complexity of the petroleum industry they attempt to govern, without becoming too complex for enforcement.[238]

3.5 Assessment

Nigeria derives a lot of income from crude oil production and this income has enriched many politicians and government officials.[239] In a bid to maintain this income

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[236] John T. Scholz, "Voluntary Compliance and Regulatory Enforcement", (1984) 6 Law & Pol'y 385 at 387.
[237] Kimberly D. Krawiec, "Cosmetic Compliance and the Failure of Negotiated Governance" (2003) 81 Wash U.L.Q. 487.
[238] See *supra* note 236.
[239] Nigeria derives about $20 billion annually from the sale of its crude oil. Greedy and corrupt politicians and government officials have over the years treated this income as their personal source of wealth to the detriment of the country as a whole. See Sampson, *supra* note 156.

flow, actions unfavorable to natural gas conservation have been and are still being condoned. Legislation to effect natural gas conservation has been largely half-hearted, with no effective enforcement mechanism or necessary tools for its implementation. The years of negligent waste therefore require an urgent solution.

That is why the *Re-injection (Amendment) Bill* and *Gas Flaring Bill* could not have been introduced at a better time. Yet until these Bills are enacted and effectively enforced, the government's attempt to conserve the country's natural gas by reducing gas flaring are mere political posturing. Perhaps the solution to resolving the problem of gas flaring is the provision of opportunities and fiscal incentives for gas utilization. Alberta has successfully made such provisions. The next section will review the provisions that Nigeria has made for the utilization of its natural gas.

4 UTILIZATION OF NATURAL GAS

The development and utilization of natural gas in Nigeria has been impeded by several factors.[240] Initially, the Government's approach was to compel utilization by threat of the stick.[241] The failure of such approach necessitated a change in the

[240] The most notable of these are: the treatment of natural gas on similar terms as petroleum, following largely from s.15 of the *Petroleum Act*, *supra* note 17, which defined petroleum to include natural gas; the absence of a ready market for natural gas, both domestic and international; high political risks in the Niger Delta coupled with uncompetitive tax and incentive schemes that discouraged potential investors; relative expense of gathering associated gas in Nigeria, given the difficult (swampy) terrain in most oil fields, the small size of the fields and the fact that natural gas supplies from such fields cannot be guaranteed, since this is dependent on the continued production of oil from the fields; the non-deregulation of the natural gas sub-sector, especially in relation to appropriate pricing of gas to public utilities; government's preoccupation with political rather than economic issues in its allocation of resources, and general approach to the industrial sector. See Nnona, *supra* note 1 at 286.

[241] One of the earliest measures taken by the Government to encourage the utilization of associated gas was the promulgation of the *Re-injection Act*, *supra* note 115, and its consequent amendment. The *Re-injection Act* was a law articulated to encourage natural gas utilization and conserve the country's huge reserve of natural gas. It is however regarded as being more of a pro-gas utilization legislation, rather than a conservation legislation. The *Re-injection Act* provides penalties for associated gas flaring that could be as

government's approach. Now, the initiative to encourage utilization of the country's natural gas is based on a four-pronged approach: the development of a natural gas policy, legislative reviews, fiscal reforms, and a gas master plan.[242] This section will examine how this approach has played out in the domestic and non-domestic utilization of the country's natural gas.

4.1 Domestic Market

The domestic utilization of Nigerian natural gas is regulated in two important ways: through the monopoly of the Nigerian Gas Company ("NGC"), and the government fixing of price for locally consumed natural gas. The NGC, a subsidiary of NNPC, is a monopoly that manages the country's gas transmission and distribution pipeline network of about 1,000km. It also has the exclusive right to purchase gas from upstream producers for transmission to the consumers, through its pipelines.[243] According to George Nnona,[244] the huge costs of constructing gas pipelines and the

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severe as forfeiture of concessions. The "threat of the stick" approach is still largely utilized today. See *supra* note 3 at 163; Akanbi, *supra* note 198; & Reuters, *supra* note 196.

[242] The Natural Gas Policy is aimed at promoting a public-private sector partnership for the orderly and rapid commercialization of the country's natural gas resource for the development and diversification of the domestic economy. It is also aimed at recovering maximum revenue possible from gas utilization. The legislative review is aimed at reviewing existing laws that would enable the optimal utilization of the country's natural gas. The fiscal reform deals with the development of new fiscal regimes for natural gas projects that is simple and flexible and that will ensure that Nigeria receives an appropriate share of the economic rent generated from the production and utilization of natural gas resource. Lastly, the gas master plan is being developed to provide a framework for Nigeria to maximize value from its gas resource through leveraging the multiplier effect of gas in the domestic economy and optimizing Nigeria's share in the high value export market. The master plan is to also facilitate timely and cost effective gas capacity additions to meet unprecedented global and domestic gas demand. See *supra* note 13; Edmund Daukoru, (Former Minister of Energy for the Federal Republic of Nigeria), "Achievements and Successes of the Present Administration: Policies for the Future" "keynote address" (Paper presented at the opening ceremony of the Nigeria Oil and Gas Conference, Tuesday, 6 February 2007) [Unpublished] at 9-12.

[243] See Nnona, *supra* note 1 at 294.

[244] *Ibid*.

underdeveloped nature of the domestic natural gas market have combined with government policy to entrench NGC's position in Nigeria.[245]

The Nigerian government also has control over the price to be paid for gas in Nigeria. This is by virtue of schedule 1, paragraph 35 of the *Petroleum Act,*[246] which obliges a lessee to obtain the approval of the Federal government as to the price at which natural gas produced by the licensee or lessee (and not taken by the Federal government) is sold.[247] The exercise of the power to determine the price of natural gas has not always been based on sound economic principles. The exercise of this power, coupled with the monopoly of the NGC, has hindered investments that would have aided the development of the domestic gas market in Nigeria.[248]

Certain measures have been taken by the government in the last few years to develop the domestic market for natural gas. These measures are in form of incentives. The major laws embodying these incentives are the *Finance* (*Miscellaneous Taxation Provisions*) *Decree* 1998,[249] and *Finance* (*Miscellaneous Taxation Provisions*) *Decree* (No. 2) 1998.[250] The effect of these laws is to provide fiscal incentives to both

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[245] *Ibid*. at 294. NGC's monopoly in respect of distribution has since been reduced with the establishment of Shell Nigeria Gas Ltd. in 1998 and Gaslink Nigeria Ltd. The entrance of these two companies has increased domestic consumption of natural gas: from about 197 million scf/d in 1999 to about 573 mmscf/d in 2004. The monopoly of NGC in the transmission sector has however hindered the free flow of natural gas to these distribution companies. See Omorogbe, Oil and Gas Law, *supra* note 23 at 56.

[246] *Supra* note 17.

[247] While sch. 1, para. 35(b)(i) of the *Petroleum Act*, *ibid*., clearly relates to associated gas only, para. 34(b)(ii) does not appear to be so circumscribed. While the latter speaks of 'natural gas produced with crude oil by the licensee or lessee', and not 'natural gas produced with crude oil by the licensee or lessee' as in sch. 1, para. 35(b)(i). The power of the Federal Government to determine the selling price of natural gas produced by the lessee therefore extends to both associated and non-associated gas. See Nnona, *supra* note 1 at 294-295.

[248] For example, the government has often insisted on gas prices for public utilities (which the NGC does not have the option of stopping gas supplies to) far below the average price obtained for private companies utilizing natural gas. These actions therefore create an uncompetitive gas market, bogged down by inefficiencies and government control and thus largely unattractive to private investors. See Nnona, *supra* note 1 at 294-295.

[249] Decree No. 18 of 1998.

[250] Decree No. 19 of 1998.

downstream and upstream companies engaged in gas utilization,[251] as well as all gas development projects.[252] For the upstream gas sector, the following fiscal incentives are provided by the Statutes:

1. All investments made in separating natural gas from the reservoir into usable products are to be treated as part of the oilfield development. The effect of this provision is to allow 85% deduction rates under the *Petroleum Profit Tax Act*[253] instead of the 30% rate it could have been under the *Company Income Tax Act*;[254]
2. Transfer of gas from upstream to downstream locations or from natural gas liquid extraction plants to gas-to-liquid facilities at 0% PPT and 0% royalty;[255] and
3. Capital investments facilities used to deliver associated gas in usable form at designated points are also to be treated as part of oilfield development (the effect of this is the same as in (1) above).[256]

For the downstream gas sector, the fiscal incentives are as follows:

1. Taxation under the *Company Income Tax Act*[257] rate of 30%, as against the *Petroleum Profit Tax Act*[258] rate of 85%;
2. An initial tax holiday period of 3 years, with a possible renewal for another 3 years;
3. Tax exemption for all dividends distributed during the period of the tax holiday;
4. Accelerated capital allowances after the tax holiday as follows: 90% annual allowance with 10% retention for investments in plant and machinery; and 15% additional investment allowance which will not reduce the value of the asset; and
5. Deductibility of interest on loans for natural gas projects provided the approval of the Federal Ministry of Finance is obtained before the loan is taken.[259]

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[251] For example, companies engaged in marketing and distribution of gas for domestic or industrial purpose.
[252] For example, industrial projects that use gas, namely gas power plants, gas-to-liquid plants, fertilizer plants, gas distribution and transmission pipelines.
[253] *Supra* note 78.
[254] LFN 2004, c. C21.
[255] See Nnona, *supra* note 1 at 289. Royalty rates for these transfers used to be 5% for offshore gas and 7% for onshore gas.
[256] *Ibid*.
[257] *Supra*, note 254.
[258] *Supra*, note 78.
[259] See Nnona, *supra* note 1 at 288-289.

Before the enactments of the above Decrees,[260] the Associated Gas Framework Agreement ("Gas Framework") had made provisions for specific fiscal incentives to encourage utilization of associated gas and reduce gas flaring. The fiscal incentives it provides are similar to those found in the Decrees. These fiscal incentives have now been translated into legislative enactments through an amendment to the *Petroleum Profit Tax Act*,[261] introduced by the *Finance* (*Miscellaneous Taxation Provisions*) *Decree*.[262] While the Gas Framework set the petroleum profit tax for natural gas at 40%, the Decrees[263] reduced it to the *Company Income Tax Act*[264] rate of 30%, and also increased the 3 years tax holiday under the Agreement to 5 years.[265]

The physical characteristics of natural gas and the long distance between Nigeria and the closest natural gas market means that natural gas is readily available for the domestic market. However, the utilization by the domestic market is fraught with problems, mainly because its commercial usage within a domestic setting requires levels of technology, infrastructure and investment that do not currently exist in Nigeria.[266] Nevertheless, there is an increasing domestic demand for natural gas in the country,[267]

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[260] *Supra*, notes 249, 250.
[261] *Supra*, note 78.
[262] *Supra*, notes 249. See also *Finance (Miscellaneous Taxation Provisions) Decree* No. 30 of 1999 [Decree No.30]. These incentives are now contained in the *Petroleum Profit Tax Act*, *ibid.*, s. 11(a). The provisions in this section have effectively superseded the various incentives granted under the Gas Framework. See *supra* note 5 at 222, 315.
[263] Nos. 18, 19 & 30, *supra* notes 249, 250 & Decree No 30, *ibid*.
[264] *Supra*, note 254.
[265] See Omorogbe, Oil and Gas Law, *supra* note 23 at 77; Nnona, *supra* note 1 at 298.
[266] See Omorogbe, Law and Investor Protection, *supra* note 4 at 180, Omorogbe, Oil and Gas Law, *supra* note 23 at 55; Gunter Schramm, "The Changing World of Natural Gas Utilization" (1984) 24 Nat. Resources J. 405 at 421, 436.
[267] Several industrial plants and commercial buildings require significant quantities of fuel. The economics of using natural gas as a fuel is determined by the cost of providing a pipeline to the consumer. However, the power plants consume a considerable quantity of gas in comparison with the industrial plan and commercial buildings. Therefore, new gas development and the gas transmission system backbone will be driven by the subsidiary networks off the high-pressure system. This has already begun to occur in the Lagos area where commercial companies for distribution of gas to major clients have built a medium pressure distribution system. See *supra* note 3 at 177; *supra* note 5 at 219.

principally from the power sector,[268] the fertilizer, aluminum smelting, petrochemical, iron and steel, cement and other industries.[269] Secondarily, a very small amount of natural gas in form of Liquefied Petroleum Gas ("LPG") is utilized by households and restaurants as a cooking fuel.[270] Nigeria, being a tropical country, does not have heating needs thus the quantities of natural gas used for industrial and residential heating is minute.[271] Although natural gas is useful for cooling purposes, this has not been fully explored in Nigeria.

The Government is currently examining the use of Compressed Natural Gas ("CNG") as an option for the transport industry.[272] The requirements of the domestic market are met by both associated and non-associated gas, but because associated gas is the more expensive alternative, an increased domestic market is likely to make little or no difference to the current high levels of associated gas being flared in the country.[273]

Apart from the above, several domestic projects utilize natural gas. Two major projects in this regard are the Gas Turbine Power Plants, which are utilized by some states and private sector industries to generate electricity independently from the national

[268] Nigeria has nine major power stations. Five of the stations are gas-powered, three are hydroelectric power stations and one is powered by both gas and hydropower. The tenth power station is a diesel-generating power station and generates only 2MW to the National Grid. The five gas-powered stations contribute 3,942MW to the National Grid's total of 5,904 MW. See K. I. Idigbe & S. O. Onohaebi, "Repositioning the Power Industry in Nigeria to Guarantee Reliability in Operations and Services" (2009) 4 (2) J. Engineering and Applied Sciences 119.
[269] See *supra* note 3 at 164-166; *supra* note 29.
[270] The LPGs are bottled and sold as cooking fuel. This use has not contributed a lot to natural gas usage in the country because most of the population still depends on biomass to produce energy required for cooking. See Omorogbe, Oil and Gas Law, *supra* note 23 at 56.
[271] See Schramm, *supra* note 266 at 427.
[272] See Daukoru, *supra* note 242 at 12.
[273] Omorogbe, Law and Investor Protection, *supra* note 4 at 180-181.

electricity provider,[274] and the Escravos Gas Project 1 and 2 ("EGP"), which commenced operations in 1997.

The EGP, which was completed at a cost of $550 million, represents the first significant associated gas recovery project in Nigeria. It is a product of the joint venture between the NNPC and Chevron Nigeria Ltd., with the objective of exploiting associated gas produced from the joint venture's oil fields in the Escravos area of the Niger Delta for power generation and general industrial demand. A 240 mile Escravos Lagos Pipeline completed in 1988, links Escravos with Lagos State, the commercial centre of Nigeria.[275] Apart from utilizing gas for domestic use, the EGP also utilizes natural gas for export to other West African countries and international markets.[276] There are currently plans to expand the EGP 2, to construct a third EGP and a Gas to Liquids Project. These projects, which are expected to be completed in 2009, will cost US$1.7 billion.[277]

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[274] Examples of such projects are the Lagos State Independent Power Project, and the Afam, Aba, Sapele, Geregou, Papalanto, Okitipupa, and Ibom Independent Power Plants. See Omorogbe, Oil and Gas Law, *supra* note 23 at 57; "Nigerian Non-Oil Projects", online: Nigeria Oil and Gas <http://www.nigeria-oil-gas.com/nigeria_non-oil_projects-103-1-2-art.html>.

[275] See *supra* note 5 at 225; Omorogbe, *supra* note 23 at 61-62.

[276] The EGP 1 and 2 processes about 300 million cubic feet of gas per day and produces LPG for sales to international markets and pipeline quality gas for domestic uses. See Omorogbe, *supra* note 23 at 62.

[277] The EGP will process nearly 400 million cubic feet a day of otherwise flared associated gas. It will extract about 35,000 barrels a day of natural gas liquids and prepare the natural gas as feedstock for the Escravos Gas to Liquid facilities, which will produce about 34,000 barrels per day of clean fuels, virtually free of sulphur, nitrogen and other pollutants. These fuels will be marketed primarily in Europe, although some products may be sold in the US. The Escravos Gas to Liquid Project will form an integral part of the Nigeria's overall gas utilization strategy that includes domestic natural gas sales, regional natural gas sales through the West Africa Gas Pipeline (WAGP), and international sales of gas to liquid products. See Chevron Corporation, "Nigeria Fact Sheet: Highlights of Operations" Chevron Corporation, 2001-2008, at 3 and Escravos Gas-to-Liquid Project, Niger Delta, Nigeria; Chevron, "ChevronTexaco Awards Major Contract for Nigerian Gas-To-Liquids Project: Company Advances Gas Commercialization Strategy in Nigeria" online:
<http://www.chevron.com/news/press/release/?id=2005-04-08>. There are currently indications that the projects may cost up to $6 billion and that this may delay the 2009 completion date. See Alexander Oil & Gas Connections: Company News Africa, "Nigeria Moves to Save Escravos Gas Project" *Alexander Oil & Gas Connections* (25 November 2008), online: Alexander Oil & Gas Connections <http://www.gasandoil.com/goc/company/cna84876.htm>. See also, Green Car Congress, "Sasol Reduces Economic Interest in Escravos GTL Project, Sells to Partner Chevron" September 6 2008, online: <http://www.greencarcongress.com/2008/09/sasol-reduces-e.html>.

4.2 Export

Apart from the domestic markets, Nigeria's natural gas is or can also be sold in international market and in an emerging regional market. Natural gas can only be transported in gaseous form via pipelines, or in liquefied form in specially constructed cryogenic tankers. But these modes require buyers, who will be linked to their sellers through the pipeline network or who will have re-gasification plants, to convert the liquefied natural gas ("LNG") back to natural gas.[278]

Internationally, the three major natural gas markets are situated in Asia, Europe and the U.S.[279] Regionally, three major markets exist in the Republic of Benin, Ghana and Togo.[280] The nature of natural gas makes the natural gas market largely inflexible, and it is difficult for new suppliers to enter into these existing markets if the supplier is situated some distance away from prospective markets.[281] Nigeria has adopted measures to make its natural gas price competitive with those of existing suppliers. First, special measures have been dedicated to specific export-oriented gas utilization initiatives. Second, general measures have been introduced to encourage the export of gas. These measures are in the form of fiscal incentives like those for the domestic market.

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[278] Omorogbe, Oil and Gas Law, *supra* note 23 at 55.
[279] *Ibid.*; Eghre-Oghene & Omole, "The Economics of the Nigerian Liquified Natural Gas Project" (1999) 23:4 OPEC Review 303 at 311 [Eghre-Oghene & Omole].
[280] Omorogbe, Oil and Gas Law, *supra* note 23 at 63.
[281] The Asian market consist of Japan principally, and to a lesser extent Korea and Taiwan. While the European market is linked by pipeline to natural gas imports from the Netherlands, the Soviet Union, and Algeria and also take LNG imports from Algeria and Libya. Lastly, The United States principally imports its natural gas from Canada and Mexico. See Omorogbe, *ibid*. at 55-56; Eghre-Oghene & Omole, *supra* note 279.

4.2.1 Fiscal Incentives

Apart from project specific incentives like those provided by the *Nigeria Liquefied Natural Gas* (*Fiscal Incentives, Guarantees and Assurances*) *Decree*[282] (NLNG Decree) and *Oso Condensate Project Decree*[283] (*Condensate Project Decree*), other fiscal incentives include those provided by the *Oil and Gas Export Free Zone Decree* (*Export Free Zone Decree*),[284] and the *Nigeria Export Processing Zone Decree* (*Export Processing Zone Decree*).[285] The *Export Free Zone Decree* designates the Onne/Ikpokiri areas of Port-Harcourt, Rivers State, as an Export Free Zone to be managed and controlled by the Oil and Gas Export Free Zone Authority.[286] The purpose of the Decree is to encourage investment in gas utilization. Enterprises operating in the Export Free Zone, and approved by the Authority are exempted from all taxes and levies imposed by the different levels of Government in Nigeria. [287]

The *Export Processing Zone Decree* established the Nigeria Export Processing Zones Authority to administer areas designated as export processing zone by the President.[288] The same incentives available under the *Export Free Zone Decree* are also available under the *Export Processing Zone Decree*.[289] Although closely related to the *Export Free Zone Decree*, the *Export Processing Zone Decree* stands apart in its own right, as embodying incentives for processing natural gas or gas-related goods for export. This is because the areas covered by the *Export Free Zone Decree* are different from the

[282] Decree No. 39 of 1990 (NLNG Decree). This Decree has since been amended by The *Nigerian LNG (Fiscal Incentives, Guarantees and Assurances) Decree* No.113 of 1993, LFN 2004, c. N87.
[283] Decree No. 15 of 1990.
[284] Decree No. 8 of 1996, amended in 1998 and consolidated in 1999 LFN 2004, c. O5.
[285] Decree No. 63 of 1992, LFN 2004, c. N107.
[286] *Export Free Zone Decree*, *supra* note 284, ss. 1-2.
[287] *Ibid*., s. 8.
[288] *Ibid*. 291, ss. 1-2.
[289] *Ibid*., s.18(1), (3).

areas envisaged by the *Export Processing Zone Decree* – the Free Zone encompasses Calabar Port in Cross Rivers state, but is capable of including other designated areas by virtue of section 1 of the *Export Processing Zone Decree*.[290]

If the fiscal incentives provided by the *Export Free Zone Decree*[291] and *Export Processing Zone Decree*[292] are to be fully utilized for natural gas development, it is advisable to amend section 5(2) of the *Export Free Zone Decree*,[293] as the continued application of that section might create bureaucratic conflict between the two administrative bodies. The section confers power on the Oil and Gas Export Free Zone Authority to take over and perform some functions being hitherto performed by the Nigerian Export Processing Zone Authority as they relate to the export of oil and gas from any of the Export Processing Zones established by the *Export Processing Zone Decree*.[294] The effect of this provision is to diminish the jurisdiction of the Nigerian Export Processing Zone Authority over oil and gas export projects undertaken within Export Processing Zones under its control.[295]

The Oso Condensate Project, which came on stream in 1992, is a joint venture between the NNPC and Mobil. The project, operated by Mobil, is for the recovery of natural gas liquids from Akwa Ibom offshore field for processing and export; and the re-injection of natural gas into the reservoirs in Oso Condensate field to maximize condensate recovery.[296] The *Condensate Project Decree* [297] provides incentives for this

[290] See Nnona, *supra* note 1 at 292-293.
[291] *Supra* note 284.
[292] *Supra* note 285.
[293] *Supra* note 284.
[294] *Supra* note 285.
[295] See also on this, Nnona, *supra* note 1 at 293-294.
[296] Condensates produced from this project is sold to further boost Nigerian oil revenue, as condensate is not regarded as falling within the OPEC quota. See Omorogbe, Oil and Gas Law, *supra* note 23 at 61.
[297] *Condensate Project Decree*, *supra* note 279.

project. The Decree permits the NNPC to borrow money in any currency to facilitate the project and to pledge its funds and assets to the project. The NNPC is also empowered to create escrow accounts abroad to keep capital and interest due from the project, in order to ensure that payments due to external creditors are not impeded by the vagaries of the Nigerian regulatory environments.[298]

The most extensive and publicized set of special incentives to a natural gas project is that given to the Nigerian Liquefied Natural Gas Limited (the company)[299] to operate the Nigerian Liquefied Natural Gas (NLNG) Project on Bonny Island, in Rivers State. The project which cost $3.8 billion utilizes both associated and non-associated gas.[300] Although the project was first initiated in 1976, the first shipment of LNG did not take place until 1999.[301]

In 2007 the company completed its sixth train,[302] increasing annual production capacity to 22 million tonnes per annum of LNG and 4 million tonnes per annum of LPG. The company plans to bring a seventh train online in late 2012, raising production capacity to 30 million tons per annum. With the coming on stream of the sixth train, Nigeria has become the third largest exporter of LNG and the company has achieved the

[298] See Nnona, *supra* note 1 at 290-291.
[299] Nigeria LNG Limited was incorporated on May 17, 1989 as a joint venture company, to harness Nigeria's natural gas reserves. The company purchases and liquefies Natural Gas for export to overseas markets. The present shareholding structure is: NNPC (49%), Shell Gas BV (25.6%), Agip (10.4%), and TotalfinaElf (15%). See *supra* note 5 at 225.
[300] Although LNG exports are one important solution to the currently low utilization of natural gas in the country, the project mostly entails the utilization of non-associated gas, which does not reduce the incidents of gas flaring. The project is however expected to solely utilize associated gas by 2010. See *supra* note 3 at 177; EIA, *supra* note 197.
[301] Omorogbe, Oil and Gas Law, *supra* note 23.
[302] An LNG train is a huge liquefaction unit, where processed natural gas is converted into a liquid state for transportation by ship. See *supra* note 5 at 241.

status of a very reliable supplier of LNG in the Atlantic Basin, serving the European and North American markets, mostly the United States.[303]

The NLNG Decree[304] grants the company a ten year tax relief period as a pioneer company. After the ten year tax holiday, the company is subject to tax under the *Company Income Tax Act*[305] but not the *Petroleum Profit Tax Act*.[306] The Decree also exempts the company, its contractors and subcontractors from all existing and future customs duties, taxes, levies, and imposts of a similar nature in respect of all necessary imports pertaining to the project.[307] In addition, the company and its shareholders are exempted from several regulatory approvals.[308]

More importantly, the government binds itself not to amend the fiscal provisions of the Decree,[309] and not to suspend, modify, or revoke the Guarantee within the lifetime of the venture without the prior written consent of the company and all its shareholders.[310] Also, it may not render invalid or unenforceable the rights and

[303] Nigeria LNG Ltd., "The Plant" Nigeria LNG online: <http://www.nlng.com/NR/exeres/CD1A6522-614B-4835-8D68-42E5A02BF6FE%2Cframeless.htm>. See also EIA *supra* note 197. But see Ejike Alike, "FG Reject Request to approve Shipment from NLNG Train 6" *Thisday Online* (13 October 2008), online: Thisday Online <http://www.thisdayonline.com/nview.php?id=125005>. According to Alike, the Federal Government has refused to grant license for the production of LNG for export from the 6th train because it claims the company is not interested in the development of the Nigerian economy. He states that the feeling in the Presidency is that the operators have not shown serious willingness to make gas available for power plants and other domestic uses in the country. This is because of the policy review on gas utilization which places priority on meeting domestic gas demand before any consideration can be given to exports [Alike]. This is indeed a very curious development as the same Federal Government owns 49% interest in this company.

[304] *Supra* note 282, ss. 1 & 2.

[305] *Supra* note 254.

[306] *Supra* note 78.

[307] NLNG Decree, *supra* note 282, s. 7(1) & sch. 2 para. 3.

[308] For instance, by s. 6(10) of the NLNG Decree, *ibid.*, the company is not subject to the provisions of the *National Shipping Policy Act* 1987, LFN 2004, c. N75.

[309] NLNG Decree, *supra* note 282, sch. 2.para. 2.

[310] *Ibid.*, sch. 2 para. 6.

obligations created by the contract entered into by the shareholders and other contracts and arrangements contemplated by the contract.[311]

Further, the company and its shareholders, in their capacity as shareholders, shall not in any way be subject to new laws, regulations, taxes, duties, impositions or charges of whatever nature, which are not generally applicable to companies incorporated in Nigeria.[312] Disputes may only be submitted to arbitration before the International Centre for the Settlement of Investment Disputes.[313] Given the provisions of the NLNG Decree, particularly the arbitration and stabilization clauses,[314] the legislation represent a foreign investment contract enacted and given force of law in Nigeria.[315]

As a result of the success of the LNG project, other LNG projects are currently envisaged.[316] In addition, other projects that have also been initiated to utilize natural gas include the West African Gas Pipeline Project (WAGP Project) and the Trans-Saharan Gas Pipeline Project (TSGP Project).

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[311] *Ibid.*, sch. 2 para. 1.
[312] I*bid.*, sch. 2 para. 3. This clause raises some environmental concern, as the company may not be bound by laws that seek to mitigate the environmental impact of natural gas development.
[313] *Ibid.*, sch. 2 para. 22.
[314] See generally, *ibid*. sch. 2.
[315] According to Omorogbe, the intent of the Decree was to effectively insulate the company from the prevailing legal and policy investments climate and from control by various bodies, conflicting rules, bureaucratic delays, and from uncertainty as to the status of the company as regards rules applicable to it. Recent occurrence in the country indicates that this is not the case. In a country like Nigeria, where political vagaries is the order of the day, stability cannot be legislated into existence. For example, the federal government has now refused to grant license for the production of LNG for export from the 6th train because it claims the company is not interested in the development of the Nigerian economy. The feeling in the Presidency is that the company has not shown serious willingness to make gas available for power plants and other domestic uses in the country. The government's stand is as a result of the recent policy review on gas utilization which places priority on meeting domestic gas demand before any consideration can be given to exports. Even after being reminded about the incentives provided in the Decree, the government remains adamant. This is indeed a very curious development as the same federal government owns 49% interest in the company. See Omorogbe, Law and Investor Protection, *supra* note 4 at 74-76, 186; Alike, *supra* note 303; *Kuwait v. American Independent Oil Company* (1982) 21 I.L.M. 976.
[316] In 2005, ExxonMobil signed a Memorandum of Understanding with the NNPC to study the feasibility of constructing a second LNG plant in Bonny Island, to come onstream in 2010. Also, in 2005, ChevronTexaco announced the possibility of constructing a US$6 billion LNG Plant in Olokola, Western Nigeria. ConocoPhillips, ChevronTexaco and Agip have also signed an agreement with the NNPC for the establishment of a US$3 billion Brass River LNG Plant. See EIA, *supra* note 197.

The WAGP project is a product of the joint venture between the governments of Nigeria, Benin, Ghana, Togo and a consortium of six oil companies.[317] Although the project was initiated in 1996, it only commenced operations in 2008,[318] and was completed at a cost of $600 million.[319] The project utilizes Nigerian associated gas that would otherwise have been flared. The pipeline is designed to supply 500 million standard cubic feet of this gas per day to customers in Ghana, Benin, and Togo for power generation and industrial applications. Chevron is the managing sponsor in the West African Gas Pipeline Company Limited affiliate, which constructed, owns and operates the 412 mile pipeline. The pipeline is connected to the 240 mile Escravos Lagos Pipeline at Alagbado Tee north of Lagos.[320]

The TSGP project is at a considerably earlier stage than the WAGP project. The TSGP project, which is expected to cost $21 billion, is aimed at putting Nigerian gas in the European market via pipelines expected to traverse 4,200km across the Sahara from Delta State in Nigeria to Algeria. The pipeline is expected to deliver between 530-710bcf

[317] The consortium is made up of: Chevron Nigeria Ltd.; Ghana National Petroleum Corp.; Nigerian National Petroleum Corp.; The Shell Petroleum Development Company of Nigeria Ltd.; Societe Beninoise de Gaz S. A.; and Societe Togolaise de Gaz S. A. See Chevron, "Chevron Named Project Manager for West African Gas Pipeline Project", online: Chevron <http://www.chevron.com/news/Press/Release/?id=1999-08-16&co=Chevron>.

[318] The pipeline delivered its first natural gas to Ghana on 11 December 2008. There are plans to increase the current 30 million cubic feet of gas that is being delivered daily. See "The West African Gas Project" *Thisday Online* (4 January 2009), online: Thisday Online <http://www.thisdayonline.com/nview.php?id=132239>.

[319] The World Bank approved an investment guarantee of $125 million for the project to encourage private investment in the project. This approval was given notwithstanding the protests from civil society groups, who had concerns about the capability of the project to reduce gas flaring (The group posits that the non-associated gas, and not associated gas would be utilized for the project), and transparency and accountability, as the WAGP Company is registered in Bermuda. See Michael Karipko "The World Bank and the West Africa Gas Pipeline Project" *Bretton Woods Project* (5 October, 2007), online: Bretton Woods Project <http://www.brettonwoodsproject.org/art-557175>.

[320] See *supra* note 317 at 4; Daukoru, *supra* note 242 at 11.

of natural gas annually to Southern Europe from the Algerian Mediterranean by 2016. The modalities of the project are the subject of ongoing negotiations.[321]

4.3 Assessment

From the examination of the existing natural gas markets and projects, it seems that natural gas utilization in Nigeria has fared better under the government's new approach than the previous approaches. The new approach and the stability in the government[322] have gone a long way in encouraging investors to undertake capital intensive gas utilization projects. Even then, natural gas development is still at a very nascent stage, as only about 15% of Nigeria's natural gas reserve is committed to existing projects.[323]

Further, these projects mostly utilize non-associated gas, which means that produced associated gas is still largely flared, making the country the 2nd highest natural gas flarer in the world, after Russia.[324] The utilization of non-associated gas at the expense of associated gas that is being wasted does not bode well for Nigeria's natural gas reserve. This state of affairs is likely to continue as long as it remains more economical to flare gas, and for as long as there is no concise, articulated natural gas policy that places the utilization of gas as a priority.[325]

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[321] See *supra* note 5 at 238; Daukoru, *supra* note 242 at 11. The European Union has recently indicated its interest in assisting the Nigeria government to implement the project. Analysts say that this interest might not be unconnected with the Union's increasing interest in reducing its dependence on Russian gas following the conflict in Georgia. See Juliana Taiwo, "Trans-Saharan Gas Pipeline - Yar'Adua Happy With EU Offer" *Thisday Online* (18 September 2008), online: Thisday Online <http://www.thisdayonline.com/nview.php?id=122840>.

[322] Since 1999, there has been a stable civilian democratic government in Nigeria.

[323] According to Kupolokun, the anticipated 25% annual growth rate in Nigeria's gas demand by 2010 is expected to generate about $13 billion annually by 2012. See Kupolokun, *supra* note 13.

[324] See Lewis, *supra* note 162.

[325] Omorogbe, Law and Investor Protection, *supra* note 4 at 181.

5 SUMMARY

This Part examined and appraised the acquisition of natural gas interests in Nigeria and also the framework for the conservation and utilization of natural gas. It also highlighted factors hindering the effective development of the countries vast natural gas resource and where possible, comparisons were made to Alberta's solution to the same problem. The recommendations and concluding remarks of this thesis are set out in the next part.

PART 4

CONCLUSION

1 INTRODUCTION

This thesis has undertaken an in-depth analysis of the frameworks adopted by Alberta and Nigeria in developing their natural gas resource. The analysis highlighted the methods utilized by Alberta and compared them to those employed in Nigeria. Three core regimes - effective regimes for the acquisition of natural gas rights, for the conservation, and for the utilization of natural gas resources – have assisted in examining the two frameworks. The environmental regime was not fully employed, as this thesis is only a first step towards sustainable development.

The analysis revealed that unlike Nigeria's framework, Alberta's framework, although not perfect, has nonetheless enabled the effective development of the province's natural gas resource, and might be adapted to achieve sustainable development if the government commits to this goal. To this end, those aspects of Alberta's regime that are suitable for effective development will be recommended for use in Nigeria. In addition, some steps Nigeria and Alberta have to take to enable them develop their natural gas resource in a more sustainable manner will be recommended.

2 APPLICATION OF ALBERTA'S NATURAL GAS DEVELOPMENT FRAMEWORK TO NIGERIA

Nigeria and Alberta both have vast natural gas and other mineral resources, which are mostly state-owned. Alberta struggled with the problem of gas flaring for many years

just as Nigeria is doing today. Their regulatory frameworks reflect their similar common law heritage and they both rely greatly on revenue derived from the exploitation of their mineral resources for the development of their economy. Although similar in this respect, both jurisdictions have certain differences which make it difficult to expect Nigeria to wholly apply Alberta's framework in developing its natural gas resource.[1]

For Nigeria to wholly adopt Alberta's framework will be antithetical to the purpose of this thesis, which is to advocate the effective development of Nigeria's natural gas resource. A positive use of the differences between the two jurisdictions will require modifications to be made to Alberta's framework to suit Nigeria's peculiar condition.[2] Care will be taken in modifying this framework, so that the inherent concepts of the framework are preserved. To better appreciate these differences, the peculiar circumstances that obtain in both jurisdictions are restated below.

2.1 DIFFERENCES BETWEEN ALBERTA AND NIGERIA

i. **Governance:** While Alberta is a developed province, Nigeria is a developing country, with many attendant problems. First, there is no widespread citizen involvement in governance. This makes it virtually impossible to know the effect a particular law or policy might have on the citizenry. In the regulation of oil and gas development, policies and legislation that would best benefit the people are

[1] Similarities are a major source of strength for the idea of one jurisdiction to fully apply to another. See Ibironke T. Odumosu, "Transferring Alberta's Gas Flaring Reduction Regulatory Framework to Nigeria: Potentials and Limitations" (2007) 44 Alta. L. Rev. 863 at 872.

[2] Jurisdictions that developed earlier responses to problems developed these responses to suit their peculiar needs and circumstances and while a problem might not be peculiar to a particular jurisdiction, the method adopted in responding to the said problem might be. As such, a wholesale legal transplant might not be a very effective means of dealing with similar problems in other jurisdictions, in spite of the fact that it might appear efficient in the first jurisdiction. See *ibid*. at 894.

jettisoned for the narrow interests of politicians. As a result, oil and gas policies are often inconsistent with the people's needs.

Second, the willpower to administer and enforce existing laws is often absent, mainly because of lack of infrastructure and basic necessities required to administer and enforce such laws and the interests of government officials in the largesse received from those that benefit from ineffective government policies.

Third, there has been unsteady government, characterized by politicians that are more concerned with amassing power and wealth rather than sustainably developing the country's natural resources. Lastly, there is almost always no love lost amongst the various arms of government, which does not help the development of the country.

ii. **Ownership of mineral resources:** The Nigerian Federal government acquired ownership rights to all the natural resources within its territory at the time of independence, while Alberta fought hard before it acquired ownership. This has resulted in Alberta having a better appreciation of the value of its natural resources than Nigeria. Nonetheless, it is always desirable for a government to have ownership rights over the natural resources within ones jurisdiction, as this will enable it to easily enact policies in all aspects.

iii. **Acquisition of natural gas rights:** While Alberta recognizes natural gas as a distinct resource and makes provisions for its acquisition separate from crude oil, Nigeria does not. The definition of petroleum to include natural gas in section 15 of the *Petroleum Act* and vague provisions of other laws has led to an uncertain investment environment.

iv. **Dependence on oil and gas revenue:** While oil and gas revenue is the main source of income for both jurisdictions, Alberta depends on it a lot less than Nigeria. If the revenue from oil and gas is depleted, the province can still survive on revenue from its forestry, agricultural, petrochemical, manufacturing, food processing and service industries. The province can also survive on interest payments from its Heritage Savings Fund, its long term investments, and, if necessary, the constitutionally guaranteed equalization fund from the Federal government.[3] On the other hand, Nigeria's economy depends solely on revenue derived from the exploitation of its oil and gas resources. If revenue from this source ceases, it will have a catastrophic effect on the country's GDP. As a result of this dependence, the country is less able to effectively enforce its natural gas conservation measures.

v. **State participation in the development of mineral resources:** By virtue of the joint venture arrangement and other contractual arrangements, the Nigerian Federal government, through the NNPC, actively participates in the development of its oil and gas resources. The Minister's dual role as head of the Department, as well as chairman of the board of the NNPC, makes it difficult for the Department to effectively regulate the industry. On the other hand, Alberta no longer owns any company that participates in the development of oil and gas resources. Alberta has benefited immensely from the private development of its natural resources. Infrastructure that the Crown might ordinarily not be able to put in place is in place because of private development. This has also enabled the independent Crown regulation of the system. In contrast, the Nigerian Federal

[3] See *Constitution Act, 1982,* being schedule B to the *Canada Act 1982* (U.K.), 1982, c.11, s. 36(2).

government is involved in most of the development through its joint venture and other contractual arrangements. But for the ways they are managed, these contracts would have been powerful tools for effective development.

vi. **Independent Regulatory Body:** In Alberta, an independent Board, the Energy Resources Conservation Board ("the Board"), regulates the development of the province's natural gas resource. This is unlike the situation in Nigeria where the regulatory body, the Department, cannot be said to be independent as it was and is still closely linked to those it regulates. Also, while the Board has been able to work co-operatively with other regulatory bodies to achieve its mandate, the Department has not been able to do the same.

vii. **Utilization Opportunities:** Alberta has an extensive natural gas gathering and pipeline infrastructure, with which it gathers and supplies natural gas to its domestic consumers and regional and international markets. The proximity of the other provinces and the United States has helped Alberta in the development of its natural gas resource. Nigeria on the other hand has no developed gas gathering and transmission infrastructure and is very far from its closest international market. But for recent projects like the LNG and the WAGP projects, it would have been next to impossible to bring the country's natural gas to regional and international markets.

Also, in Alberta, the availability of facilities with which to utilize natural gas and favorable governmental policies have led to a highly developed domestic natural gas market. This is unlike the situation in Nigeria where inadequate

facilities and ineffective governmental policies have stunted the development of its domestic natural gas market.

viii. **Climatic Condition:** While Alberta has a cool and continental climate, which means that its residents require a lot of natural gas for heating purposes, Nigeria has a tropical climate. As such Nigeria does not require natural gas for heating purposes but it would presumably have some use for cooling.

3 RECOMMENDATIONS

Alberta has achieved an effective development of its natural gas because of the framework it has in place. If Nigeria adopts a similar framework, it will be able to develop its natural gas to a level close to that of Alberta. In addition to this, Nigeria's peculiar circumstances will require that some actions be taken that are not found in Alberta's framework. Some actions that Nigeria can take to effectively and subsequently, sustainably develop its natural gas resource are set out below. For ease of reference, these recommendations are set out under four major heads – acquisition of natural gas rights, conservation of natural gas, utilization of natural gas, and sustainable development of natural gas.

3.1 Acquisition of Natural Gas Rights

The following suggestions will assist Nigeria to fully assert its right of ownership to its natural gas resource and to derive appropriate benefits from its development.

First, the government should amend the *Petroleum Act*, pursuant to its powers under section 9 of the *Petroleum Act* and the compliance with law clause of the OPL and OML. Like the *Mines and Minerals Act*, petroleum should be defined as including oil

either alone or with gas at a low gas-oil ratio. This would ensure that oil producers have sufficient gas to aid oil production. In addition, a clear and unambiguous provision re-vesting the natural gas rights in the Federal Government should be included in the Act. So as not to deter hitherto interested natural gas investors, the amendment should only be enacted after arrangements have been made to ensure fairness to existing lessees.

Second, specific legislation, similar to the Alberta Tenure Regulation, should be enacted to guide the acquisition of oil and natural gas rights under the *Petroleum Act*. Oil and Natural gas are valuable and scarce resources. Oil should not be developed at the expense of natural gas and vice versa. This is underscored by the government's duty to safeguard the interests of Nigerians by preserving finite mineral resources. In order to promote the efficient exploitation and maximize the ultimate benefit of these resources, it is therefore necessary to grant overlapping natural gas and oil leases that confer broad, unrestricted recovery rights.

As seen in Alberta, where a sophisticated regulatory regime exists, split title can lead to conflicts between the holders of separate mineral rights. Conflict may occur where the gas-cap gas is produced by the oil lessee. Another instance is where initial or concurrent production of associated gas leads to reservoir pressure depletion, thereby sterilizing the right of the oil lessee to recover oil. For a country like Nigeria that does not have a sophisticated regulatory and statutory regime, splitting title could be the single most disastrous initiative in its energy policy. Billions of dollars could be lost in revenue. It will therefore be wise to leave the oil and gas in the hands of the existing lessees and stringently enforce anti-flaring laws.[4]

[4] See Recommendations on Conservation in 3.2 below.

Should the government ever decide to split title, it is advised that the following be considered. It should however be noted that, in order for the recommendation to be feasible, a very sophisticated engineering and scientific system has to be put in place.

The severed oil and natural gas rights should be granted to separate interests. If the rights are granted to the same interest, the oil lessee may decide not to utilize the produced gas, thereby frustrating the whole purpose of splitting title, which is to maximize the benefits from the development of mineral resources; while the recovery of associated gas by the natural gas lessee may sterilize the ability to recover oil, thereby causing loss of resource revenue.

Where these interests are nevertheless granted to the same lessee, the oil lessee should be encouraged to either utilize or enter into arrangements with companies that may wish to utilize the associated gas. On the part of the natural gas lessee, the Department should assess whether or not associated gas production would significantly affect oil recovery. Where it will affect oil recovery, the lessee should be directed to conserve reservoir pressure by leaving the associated gas in place, but where such pressure depletion would not significantly affect oil recovery, production should be permitted. Since the restriction on gas production might create undue hardship for the natural gas lessee, various schemes should be put in place to alleviate this hardship. These schemes may include the payment of compensation by the government and the waiver of rentals.

If gas production were to be restricted in the oil areas, the net effect on total gas production in the country would be negligible. Non-associated gas production in other parts of the country would, at least temporarily, make up the difference. Considering the

chill that would be placed on natural gas development as a result of restrictions on production, the government and industry stakeholders should work together to develop a technology that would enable both natural gas and oil to be developed, each at its own pace without obstruction or risk from the other.

Where the oil and gas rights are granted to separate interests, provisions should be made for the oil lessee to compensate the natural gas lessee for any gas that is inadvertently produced with oil. Preferably, both lessees should be encouraged to enter into production-sharing agreements. To guarantee that this agreement will be reached amicably, there should be legislation empowering the Department to regulate such an agreement. Further, an accurate measuring system should be set up to enable the producers determine the amount of gas or oil that is being produced from the petroleum reservoir.

Third, in Nigeria and Alberta, the auction method of granting petroleum and natural gas rights has proved very successful in ensuring the receipt of a fair market value in exchange for exploitation rights. Unfortunately, unlike in Alberta, auctions are not statutorily authorized in Nigeria. In order to ensure the continued use of the auction method in Nigeria, the *Petroleum Act* and related regulations should be amended to provide for it.

Fourth, the idea of a non-renewable resources savings fund, like the Alberta Heritage Savings Trust Fund, should be explored. The benefits of such a fund are substantial. The fund provides insurance against declining revenues from resource production as non-renewable resources are depleted over time.It also ensures that future generations will benefit from the production of resources today. It can be used to help

mitigate boom and bust cycles, help provide economic diversification to rural communities, and facilitate a transition to renewable resources in the future.[5] In addition, money accumulated in such fund can help to lessen future risks and liabilities associated with environmental impact. In order to derive these benefits, Nigeria is advised to also examine and perhaps, adapt the way similar funds are being administered in Norway and Alaska.[6] Also, the country is advised to set up a research and technology fund like the Alberta Climate Change and Emission Management Fund.

Fifth, the idea of a law like the Alberta Land Stewardship Act should be explored. By enacting such a law, the government will be able to take account of and respond to the cumulative effect of natural gas development on Nigeria's land, air and water.

3.2 Conservation of Natural Gas

The inadequate provision for natural gas conservation in Nigeria has now been realized with the introduction of two distinct natural gas conservation Bills - the *Re-injection (Amendment) Bill* and the *Gas Flaring Bill*. But while the effort is commendable, the Bills, even if they are enacted, are still not sufficient to effect the conservation of the country's natural gas resource. Nigeria needs to employ the

[5] See below for recommendation on transition to renewable and sustainable energy sources.

[6] Unlike the Alberta Heritage Savings Trust Fund, which has declined significantly in value, similar funds in Norway (The Norway Petroleum Fund was created in 1990, the first transfer to the fund took place in 1996) and Alaska (The Alaska Permanent Fund was created in 1976, the same year as the Alberta Heritage Fund) has increased in value. Key differences among the funds include the following: compared to the funds in Norway and Alaska, it is much easier for the Alberta government to change the Alberta Heritage Fund's investment policies or even the structure of the fund itself; governments in Alaska and Norway still contributes to their funds on an annual basis, while oil and gas revenues, until recently, were not being transferred to the Alberta Heritage Fund; the focus of the funds in Norway and Alaska is at least partly on growing the total value of the fund over time; and until recently, the Alberta Heritage Fund was not protected from inflation (due to population increases in Alberta and the stagnant nature of the fund, on a per-capital basis it is worth much less now than it was worth in 1995). See on this, Amy Taylor et al., "When the Government is the Landlord: Economic Rent, Non-Renewable Permanent Funds, and Environmental Impacts Related to Oil and Gas Developments in Canada" online: Pembina Institute <http://pubs.pembina.org/reports/GovtisLLMainAug17.pdf> at 36-39. See also, 2008-*2009 Annual Report of the Alberta Heritage Savings Trust Fund* (Edmonton: Alberta Finance and Enterprise 2009) at 2.

recommendations below to achieve the desired level of natural gas conservation similar to that operative in Alberta.

First, the idea of an independent and quasi-judicial regulatory body like the Alberta Board should be adopted. It is commendable that the *Petroleum Industry Bill*, 2008 provides for an independent and autonomous regulatory body, the Petroleum Inspectorate, to replace the Department. The Governing Board of the Inspectorate is not dependent on the government for all its funding and it also has the necessary resources to enable it carry out its functions. The Board is however made up of members who are appointed on a part-time basis and who are liable to be sued personally for any decision they make while carrying out their functions. This may reduce their capacity to be independent and effective.

To ensure that the Governing Board carries out it functions fearlessly and independently, it is recommended that its members be appointed on a full time basis. Conservation is an on-going challenge and it requires individuals that are totally dedicated to ensuring conservation. Also, the members should be shielded from law suits. Since the inception of conservation movement in Alberta, successive conservation boards have always been protected from law suits. In the early years this was a necessity, as the boards had to take drastic actions to carryout their conservation mandates.[7]

Just like the Alberta Board, the discretion of the Governing Board should be fettered by regulatory provisions and be subject to regular oversight by the Ministry, which in turn will be answerable to the Federal Legislature. The Governing Board should

[7] See generally David H. Breen, *Alberta's Petroleum Industry and the Conservation Board* (Edmonton: The University of Alberta Press, 1993)

also be statutorily empowered to make conservation regulations. Prolonged legislative deliberations common to the Nigerian legislature will therefore be avoided.

Second, distinct natural gas conservation legislation and policy directions should be put in place. The *Re-injection (Amendment) Bill* and the *Gas Flaring Bill* should be revised to address a wide variety of gas conservation issues before their enactment. Since it is not feasible to totally eliminate gas flaring at this time, the Bills should strive to effect a substantial reduction in gas flaring and ensure that the best available conservation practices are adopted. Gas flaring should only be permitted where it is not economically or technically practical to conserve gas or where there is an operational upset, such as equipment failure. When gas is permitted to be flared, it should be regulated with guidelines mandating a reduction in volumes flared as well as combustion efficiency that controls odour and visible smoke emissions. Further, deadlines for implementing gas conservation schemes and gas flaring reduction targets should, as much as possible, not be shifted or reduced once fixed.

The applicable policy direction on natural gas conservation should also be subject to continuous improvements and constant review to incorporate results of newly conducted research and relevant conservation developments in the industry, like the development of carbon capture and storage and renewable energy technologies. The provisions of Alberta's *Oil and Gas Conservation Act*, CCEMA and *Directive 060* are instructive in this regard. Together, the Acts and Directive have been very instrumental in eliminating natural gas waste by reducing the amount of gas flared in the province and the negative impact of natural development on the environment.

Third, a new law should be enacted or existing legislation amended to provide for a precise and clear enforcement mechanism. Since it is very clear that mere threats of the stick coupled with wide discretionary powers has not effected compliance in Nigeria, the enforcement process adopted by the Board in *Directive 019* should be emulated.

Under the enforcement process, the severity of non-compliance should determine the enforcement action. Since there is egregious gas flaring in the country, only the high risk non-compliance part of the Directive's Risk Matrix should be adopted at this time. The enforcement action should be escalated as necessary in the event that initial enforcement does not result in compliance. When there has been initial high risk non-compliance, it should result in the cancellation and or suspension of permits, licenses, or approvals; the payment of non-compliance fee: or the issuance of a well closure or an abandonment order. Further failure to comply should result in the escalation of the non-compliance from an initial high risk to a persistent non compliance. This should be followed by full or partial suspension of the lessee's operations. Where the lessee does not comply with this requirement and has acted with demonstrated disregard, it should be subjected to escalated enforcement action. Such action should include the taking of corrective actions and charging the costs to the licensee as a means of ensuring compliance, or referring the matter to prosecution.

To ensure full compliance, the enforcement process should be drafted with inputs from the entire industry stakeholders. Also, the regulatory body should be provided with all the necessary tools that it requires to effectively achieve compliance. Competent professional staff should be employed to monitor compliance with the applicable legislation. The Alberta multi-stakeholder approach to the regulation of natural gas

resource should be employed. Lastly, to help future conservation efforts, records of industry activities with respect to natural gas conservation should be kept and published annually.

It is suggested that most of the above recommendations will only become useful if opportunities to utilize natural gas exist. Recommendations on utilization are set out below.

3.3 Utilization of Natural Gas

The solution to resolving the problem of gas flaring is the provision of opportunities and fiscal incentives for gas utilization. Nigeria has realized this fact but the following recommendation will provide for a more effective utilization.

First, utilization of associated gas should be encouraged by the provision of more incentives and programs. Programs, such as Alberta's deep-drilling gas program, re-injection credits, and exemption from payment of royalties on otherwise flared gas, should be implemented. Utilization of associated gas for current and future natural gas projects should also be encouraged. This makes good conservation and economic sense, as associated gas is the one that is presently being wasted through flaring.

Second, section 5(2) of the *Export Free Zone Decree*, which confers power on the Oil and Gas Export Free Zone Authority to take over and perform some functions previously being performed by the Nigeria Export Processing Zones Authority, should be amended. The continued application of that section might create bureaucratic conflict between these administrative bodies, which will not aid the proper implementation of the incentives provided under the Decrees.

Third, Nigeria should introduce programs and provide facilities to encourage domestic utilization of natural gas. The use of natural gas for cooling purposes should also be explored.

It is very important for Nigeria to develop its domestic market because of the distance to regional and international markets and also competing suppliers in these markets. Since Nigeria has sufficient LNG capacity, the economist might argue that Nigeria would benefit more from huge revenue derived from highly priced exports, rather than developing the domestic market. This is not recommended for Nigeria. From an environmental point of view, Nigerians, like international users, deserve to benefit from the use of a clean fuel like natural gas. From a social development perspective, the development of the international market to the detriment of the domestic market will create a situation where Nigerians are unable to benefit directly or indirectly from their natural gas resource. Just as with oil today, natural gas may become a scarce commodity and the export revenue might not be used to provide much needed social amenities. The prevalent practice has been that corrupt government officials divert revenue derived from oil exports for personal use.[8] These corrupt practices will persist unless the country's political system is reformed and the link between the county's politicians and those who are supposed to elect them is restored. Thankfully, there is a hint of a new chapter in the system.[9]

[8] See "Nigeria - Hints of a New Chapter" *The Economist* (14 November 2009) 30-32.
[9] *Ibid*.

3.4 Sustainable Development of Natural Gas

Natural gas development plays a unique role in the discussion of sustainable development. It is a non-renewable natural resource that earns, along with crude oil and coal, the opprobrium of those for whom sustainable development means greater reliance on renewable resources, such as solar, biomass and wind.[10] Natural gas is by far the cleanest burning of the three major fossil fuels. Composed primarily of methane, the main products of the combustion of natural gas are CO_2 and water vapor. Crude oil and coal are composed of much more complex molecules, with a higher carbon ratio and higher nitrogen and sulfur contents. This means that when combusted, coal and crude oil release higher levels of harmful emissions, including a higher ratio of carbon emissions, nitrogen oxides, and sulfur dioxide. These two also release ash particles into the environment, substances that do not burn but instead are carried into the atmosphere and contribute to pollution. The combustion of natural gas, on the other hand, releases very small amounts of nitrogen oxides and sulfur dioxide, virtually no ash or particulate matter, and lower levels of carbon dioxide, carbon monoxide, and other reactive hydrocarbons.[11]

Nonetheless, the development of natural gas adds a significant amount of green house gases to the environment, thereby increasing climate change. Also, going by the present natural gas stock, the continued development of natural gas means that there will

[10] Jacqueline Lang Weaver, "Sustainable Development in the Petroleum Sector" [Weaver, Sustainable Development] in Adrian J. Bradbrook & Richard L. Ottinger, eds., *Energy Law and Sustainable Development,* (Gland: International Union for Conservation of Nature and Natural Resources & Cambridge, 2003) at 47 [Bradbrook & Ottinger].

[11] See *ibid*. A shift from coal to natural gas to generate electricity in power plants has substantially reduced emissions of CO_2, nitrogen oxides and sulphur. In England, China, the United States, and Canada where this shift has taken place, there has been a substantial reduction in air pollution. See *ibid*

be little or nothing left for future use. This is why the development of natural gas has to be sustainable.

The United Nations Development Programme defines sustainable development in respect of mineral resources as "energy produced and used in ways that support human development over the long term, in all its social, economic, and environmental dimensions."[12] Sustainable development therefore implies that in developing a mineral resource, one must not endanger the natural systems that support life on earth.[13]

The extraction of minerals is an example of human actions that can endanger such systems. Until recently, mineral developments were small in scale and their impacts were limited. Today, the development is more drastic and more threatening to natural systems both locally and globally. The development and use of fossil fuels, such as natural gas, increases atmospheric concentrations of greenhouse gases, which in turn warm the world and changes climate systems.[14] It also reduces the amount of the resource that will be available for future use. It is therefore expedient to promote sustainable and environmentally responsible natural gas development.

To achieve this, major changes in government policies will be required. Governments should be able to merge sustainable development and economic development in decision-making.[15] For instance, a natural gas development should not merely be seen as a way of generating energy and wealth; its effect on the environment, the availability of the resource for future use, and alternative energy sources, ought to be

[12] See José Goldemberg, ed., *The World Energy Assessment: Energy and the Challenge of Sustainability*, (Global: UNDP, UN-DESA & World Energy Council, 2000) at 3.
[13] See World Commission on Environmental Development, *Our Common Future* (Oxford: Oxford University Press, 1987) at 45 [Brundtland Report].
[14] See David R. Hodas, "Energy, Climate Change and Sustainable Development" in Bradbrook & Ottinger, *supra* note 9 at 11.
[15] Brundtland Report, *supra* note 14 at 45.

taken into consideration. The challenge is great- it requires huge commitment- but the reward is greater. Some legal measures that can be taken include: transition to environmentally friendly renewable energy alternatives, like wind, solar, hydroelectric, and geothermal; carbon capture and storage programs; emissions intensity reduction targets; emission trading; and environmental impact assessment of proposed natural gas projects. [16]

4 CONCLUDING REMARKS

This thesis examined the natural gas development framework applicable in Alberta to determine if it has enabled the effective development of the province's natural gas resource, and where it has, if same can be applied in Nigeria. As revealed from the examination, Alberta has been able to effectively develop its natural gas, but while Nigeria can learn a lot from the framework adopted by Alberta, it must do so bearing in mind its peculiar condition.

While conceding that the ideas recommended in this thesis are not fool-proof, it is submitted that their application will, to a great extent, enable the effective development of the Nigeria's natural gas resource. However, the imperative for Nigeria and Alberta is to develop their natural gas resource in a sustainable manner, for the benefit of present and future generations, while exploring renewable substitutes in the short, medium, and long term.

[16] See generally on legal measures for sustainable energy development, Richard L. Ottinger & Fred Zalcman, 'Legal Measures to Promote Renewable and Energy Efficiency Resources" in Bradbrook & Ottinger, *supra* note 11 at 79.

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Appendix I Gas flaring in Nigeria Niger Delta