



Energy and the Atlantic:

The Shifting Energy Landscape of the Atlantic Basin

Paul Isbell

Wider Atlantic Series

G | M | F The German Marshall Fund
of the United States
STRENGTHENING TRANSATLANTIC COOPERATION

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This report was prepared for GMF's Wider Atlantic program, a research and convening partnership of GMF and Morocco's OCP Foundation. The program explores the north-south and south-south dimensions of transatlantic relations, including the role of Africa and Latin America, and issues affecting the Atlantic basin as a whole.

On the cover:

Oil platform construction site at Walvis Bay harbor, Namibia. © Mlenny Photography

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Executive Summary

Recent changes in global geopolitics — including the emergence of the developing world and structural crises in the northern Atlantic — have collided with ongoing trends in the energy sector to transform the future prospects of the Atlantic Basin. Many of these energy vectors are either unique to the basin or are more advanced in the Atlantic than in the Indian Ocean or the Pacific. The expansion of renewables, the shale gas revolution, the boom in southern Atlantic oil, the dynamism of liquefied natural gas (LNG), and the possible emergence of gas-to-liquids (GTL) together have placed the Atlantic Basin at the cutting edge of the energy future.

While the world remains transfixed on China and U.S. foreign policy “pivots” to Asia, the tectonic plates of the global system continue to shift, offering much economic and geopolitical potential for Atlantic countries that can seize the coming opportunities. Indeed, if we were to reframe our traditional energy focus to embrace the entire Atlantic Basin, instead of focusing on North America, Europe, Africa, Latin America, or even “the Americas,” surprising new vectors come into view.

Beyond the headlines of global affairs, an incipient “Atlantic Basin energy system” has begun to quietly coalesce. Fossil fuel supply in the basin has boomed in the last ten years, with a southern Atlantic hydrocarbons ring slowly taking shape. Meanwhile, a wide range of renewable energies — from bioenergy to solar and wind power — are now rolling out in the Atlantic faster than in the Indian Ocean or Pacific basins. The gas revolution, encompassing unconventional gas, LNG, and GTL, is also increasingly focused on the Atlantic. The energy services sector is also exploding in the southern Atlantic hydrocarbons ring. Although energy demand has moderated in the northern Atlantic, it has been growing rapidly in the south, and is projected to continue to rise, part of a wider realignment of economic and political influence from north to south within the Atlantic Basin. By 2035, the southern Atlantic alone could account for as much as 20 percent of global energy

demand, with the entire Atlantic Basin contributing nearly 40 percent.

This nascent Atlantic Basin energy system has already achieved a high degree of specific mass within the global energy economy in terms of supply, demand, critical mass, relative autonomy, and supply chain complementarity. The Atlantic Basin now hosts one-third of global petroleum production, 40 percent of the world's petroleum reserves, more than one-third of global gas production, one-third of global LNG production, 12 percent of the world's conventional gas reserves, nearly 60 percent of the presumed world total of technically recoverable shale gas reserves, and around 70 percent of global installed renewable energy capacity.

Furthermore, pure intra-Atlantic Basin trade takes up a relatively large share — around 30 percent — of both the global petroleum and liquefied natural gas markets, lending Atlantic Basin markets a certain level of depth and functional autonomy in relation to the overarching global markets. The level of extra-basin energy dependence — 15 percent in petroleum and only 6 percent in gas — is also relatively low in the Atlantic, and is likely to continue to fall. The Atlantic Basin could even become, over the coming decades, a net exporter of many forms of energy to the Indian Ocean and Pacific Basins.

A number of mutually complementary opportunities to develop energy investment and trade linkages — all along the energy supply chain in the various segments of the upstream, midstream, and downstream — have also appeared across the Atlantic space, particularly in the southern Atlantic. One example is the complementary nature of potential Southern Cone shale gas (upstream) with existing South African GTL synthetic fuel technology (downstream). Another is the opportunity for much denser, more efficiency-driven interpenetration among the energy service sectors within and across the Atlantic. Complementary opportunities also exist along the midstream, in the realm of LNG, and in the downstream, particularly with regard to investment and trade in the biofuels sector between Brazil and the Atlantic countries of West and Southern Africa, or in the product markets

for transportation fuels (between consumer and producer countries, along both North–South and South–South vectors).

The implications of such shifting energy landscapes are manifold. First, as conventional and new alternative energies expand their supply within the Atlantic Basin, the traditional dependencies of Western countries on Middle Eastern oil, already on an arc of moderation, will weaken further. The new “Great Game” in Central Asia, in which all major world powers are engaged, will become much less significant in Western strategic calculations, as will the geopolitical difficulties presented by Russia. Central Asia and the Middle East will not disappear from Western radars, but their relative weightings within Western strategic equations would be noticeably reduced.

In addition to enhanced energy security, the future development of an Atlantic Basin energy system could help bind the countries rimming the Atlantic more closely together. The deepening density of the Atlantic Basin political economy will reverberate positively upon economic development and facilitate the low carbon transformation of the global energy economy. Mobilizing the untapped potential of underutilized energy trade and investment links, particularly in the southern Atlantic, could help produce a renaissance in the Atlantic Basin, eroding the patterns of traditional economic and political dependence of the south upon the north, and moderating the risks imposed by China’s inexorable global emergence and its growing influence in the Atlantic region.

Much is at stake for the northern Atlantic. Not only does the Atlantic Basin, as a region, offer interesting potential to both improve energy security and to help build a bridge to a low-carbon future, it also holds one of the keys to transforming and rejuvenating a problematic U.S.-EU relationship, in part by broadening its scope to engage key actors in the southern Atlantic.

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Many colleagues, including a number of energy experts around the Atlantic Basin, contributed significantly to this book. I am grateful to all of them for sharing with me their perspectives on their countries' respective energy horizons, and on the potential for an Atlantic Basin energy system to emerge. However, there are a few who deserve special mention. In South Africa, these include Hilton Trollip (Cape Town Municipal Government), Andrew Marquard (University of Cape Town), Philip Lloyd (Peninsula Tech University), Dave Wright (Engen), Saliem Fakir (WWF South Africa), Rod Crompton (NERSA), Xavier Prevost (XMP Consulting), and Andre Booysen (Eskom). A particularly warm thank-you must go to Steve Thorne (SouthSouthNorth, Cape Town), who was especially instrumental in organizing interviews and preparing other logistics on the ground. In Brazil, special thanks go to Marcos Jank (UNICA) and Eduardo Monteiro (Acende Brasil). In Argentina, I would like to acknowledge Gerardo Rabinovich (Asociacion Latinoamericana de Economistas de la Energia) and Ernesto Badaraco (ITBA), and in El Salvador, Roberto Rubio (Funde).

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Preface

This study attempts to answer the following related questions: Does an Atlantic Basin energy system exist? If not, what preconditions would need to be fulfilled for such a system to emerge? What obstacles stand in the way of such a development? What would be the strategic opportunities or implications of the further formation of an Atlantic Basin energy system, particularly for key national actors in the Atlantic world?

Most of the significant energy sources and trends in the Atlantic Basin have been addressed, in one way or another, throughout the course of this study. Hydrocarbons and renewables are both analyzed in depth. Biofuels are covered (if mainly in relation to Brazil), but not nearly as thoroughly as gas-to-liquids synfuels or other modern renewables, both of which potentially have a very dynamic future as well. Nuclear energy and hydropower are not given their own specific sections, but ample reference to both is made throughout the analysis. Coal is discussed more extensively in the section on South Africa than in other parts of the study.

To evaluate the potential for an Atlantic Basin energy system — and to ascertain the extent of the recent southward shift, in both relevance and dynamism, within the Atlantic energy space — this analysis has been cast through two organizational frames: 1) the classic “energy mix,” with its more global emphasis on supply and demand with respect to traditional and new energy sources; and 2) the traditional “energy supply chain” — along which energy trade flows and around which markets take shape — with its categorical divisions between the upstream (source), midstream (transport), and downstream (processing, delivery, and consumption). In this way, we are allowed to analyze both the relative and absolute volumes, as well as internal dynamics, of any potential Atlantic Basin energy system.

The study itself is divided into four chapters: Chapter One: An Introductory Exploration of the Atlantic Basin Energy System; Chapter Two: The Shifting Energy Landscape of the Atlantic Basin; Chapter Three: Focus on the Southern Atlantic; and Chapter Four: The Future of an Atlantic Basin Energy System.

Chapter One broadly outlines the geopolitical evolution of the Atlantic Basin, identifying a new southward shift in its center of gravity; presents and delimits the Atlantic Basin energy map; analyzes the internal preconditions for, along with other external influences upon, the emergence of an Atlantic Basin energy system; and finally offers an assessment of current realities and future possibilities.

Chapter Two analyzes the Atlantic Basin's current and near- to midterm potential energy sources — including petroleum, gas, coal, biofuels, hydropower, nuclear power, and renewable energies — that round out the classic energy mix. This chapter also presents analysis on key recent and future energy trends that could hold strategic significance for public and private actors around the basin. The potential strategic ramifications of these key trends in the transportation and power realms are also analyzed in this chapter at the upstream, midstream, and downstream levels.

Chapter Three focuses on the southern Atlantic and its incipient re-emergence within the Atlantic Basin. Countries such as Brazil and South Africa are directly engaging the current onslaught of energy changes, challenges, and opportunities. The development of strategic energy and climate change policies has helped Brazil and South Africa to emerge from “South Atlantic marginalization.”¹ They have the potential to serve as vital diplomatic architects, and as mediators between the developing world and the advanced economies of their northern Atlantic Basin partners, the United States and the EU, particularly in the realm of climate change and energy policy. Brazil and South Africa have the potential to stimulate the evolution of an Atlantic Basin consciousness and to catalyze the further development of an Atlantic Basin energy system. For these reasons, they are highlighted as separate case studies.

Chapter Four includes the study's conclusions, along with an analysis of policy implications.

¹ Ian O. Lesser, “Southern Atlanticism: Geopolitics and Strategy for the Other Half of the Atlantic Rim,” Brussels Forum Paper Series, German Marshall Fund of the United States, Washington, D.C., 2010.

Definitions and Conceptual Framework

How should the Atlantic Basin be defined or delimited? For most of this study’s conceptual purposes, the Atlantic Basin begins — in visual and cartographic terms — in the north at the Arctic Ocean, moving southward and counterclockwise along the coasts of Greenland and Canada to the United States; down through the Gulf of Mexico and the Caribbean to Venezuela, the Guyanas, and the eastern Amazon Basin; and then moving on through southern Brazil, the Rio de la Plata, Argentina’s Patagonia, Cape Horn, and Antarctica. The basin then turns northward, continuing counterclockwise back up to the Cape of Good Hope, along the coasts of South Africa, Namibia, Angola, the Congo River Basin and the Gulf of Guinea, West Africa, Mauritania, Morocco, Spain, France, the British Isles, the Low Countries, Germany, Scandinavia, and back up to the Arctic Ocean. A broader definition would include the countries bordering the Caribbean Sea and the Gulf of Mexico, as well as the Mediterranean, and possibly even the Baltic. A narrower definition would probably first exclude the Baltic, and then perhaps the Mediterranean. Considering the history and geography of the Atlantic, however, a definition that excluded the Caribbean would probably be considered too narrow and less credible.

The Atlantic Basin energy economy has never been mapped, in any quantified way, as a distinct geo-economic unit. For the purposes of the data used in this study, however, we posit three different definitional criteria along a continuum — broad, intermediate, and narrow. For most of the study’s comparative purposes, however, there are typically references only to the first (broad) and the last (narrow) definitions, although there will also be frequent references to an average between the two.²

² References will be made to the “broad” and “narrow” Atlantic. When Atlantic Basin figures are given without reference to the specific category (i.e., “broad”), the reader should assume that it is an average of the figures from the “broad” and “narrow” Atlantic Basin categories — which is not always the same as the “intermediate” version of the Atlantic — in an attempt to approximate the most reasonable version of the breadth, depth, and weight of the Atlantic Basin.

- The “**broad**” **definition** of the Atlantic Basin includes in their entirety the four continents — North America, Central and South America, Europe, and Africa — that border the Atlantic, including those countries from these continents (such as Peru and El Salvador, or Kenya and Tanzania) that do not border on the Atlantic Ocean. Most analysts would probably consider this definition to be too broad. Nevertheless, it is often the most convenient measure, given that many sources do not always provide complete disaggregated data below the continental or regional level. In any event, this “broad” measure serves as one extreme boundary of the possible Atlantic Basin.
- An “**intermediate**” **definition** might include all countries that have some sort of water outlet to the Atlantic Ocean (including countries on the Mediterranean, Baltic, or Caribbean seas) but *exclude* landlocked countries and countries that *only* have a coast on the Pacific or Indian Ocean. This loose “intermediate” definition might feel, to some, more precise and convincing than the “broad” criterion: after all, would not the Baltic states have a more credible claim to an Atlantic identity than Kenya or Uganda? A somewhat stricter version of this “intermediate” Atlantic Basin might establish a “direct coastline” definitional standard. This would have the effect of further excluding all countries (such as Lithuania, Finland, Italy, and Egypt, but also Venezuela and Mexico) without a direct coast on what is strictly speaking the Atlantic Ocean. This stricter intermediate definition will also, no doubt, fail to satisfy at least some: those who might still see Mexico and Venezuela as Atlantic countries, and the Caribbean Sea as a subset of the Atlantic, as opposed to separate and apart from the Atlantic world — as many might perceive the Mediterranean reality to be.
- The “**narrow**” **definition** of the Atlantic Basin, for the purposes of this analysis, is actually an economic adjustment to the looser version of the “intermediate” definition. Although the “direct coastline” definition is probably too rigid to be meaningful to most (unless we are willing to view the claim of the Caribbean as no more, and no less, legitimate than that of the Mediterranean), a looser definition, which includes the Caribbean but excludes the Mediterranean and the Baltic, does bound the possible geographic range of the Atlantic at one

end of the continuum, opposite the other extreme, anchored by the “broad” definition (which almost universally would be considered too excessively broad). However, some countries, if only a limited few, have direct coastlines on two different ocean basins. Some of their energy production, consumption, and trade could be linked to the Pacific Basin, whereas the rest may more credibly belong to the Atlantic Basin. This is the case for the United States and Canada, for example. South Africa is also a dual-basin economy; however, that country’s Indian Ocean and Atlantic coasts form part of a continuous coastline that directly integrates these two basins. Still, because disaggregated data is often not available to break down energy and energy trade activity by ocean basin, a geo-economic adjustment is applied to the looser version of the “direct coastline” (or loose “intermediate”) definition of the Atlantic Basin: dividing in half the key data figures of those Atlantic Basin countries that also have a direct coastline on the Pacific or Indian Ocean. This would imply 50 percent adjustments to the United States, Canada, and South Africa, as well as a number of continental European countries (e.g., Germany), with their long Eastern European/Russian “backyard” (a kind of “land basin” with respect to energy trade) supplementing their Western European energy position on the Atlantic Basin.

The most reasonable, if still imprecise, definition of the Atlantic Basin would probably lie somewhere between the “narrow” and the “broad” definitional categories sketched out above. However, the “intermediate Atlantic” is often not possible to define precisely with sufficiently disaggregated data for all countries with direct coastlines on the Atlantic Ocean or the other seas into which it flows. As a result, with respect to data, percentages, proportions, and other quantified terms, this study’s “Atlantic Basin” aggregate will often be a simple average of the “broad” and the “narrow” definition — or an “approximate” definition of the Atlantic. Diplomatic or political engagement with the Atlantic Basin concept may not require establishing such a tightly defined criterion, given that any country with perceived interests in the Atlantic Basin — even if it has no direct coastline claim — could be considered an Atlantic Basin country or power, or at least an interesting partner to have around any Atlantic Basin table. However, for the purposes of assessing the size, dynamics, and geopolitical potentials of the

Atlantic Basin energy space, some basic definitional criteria must be established in order to realistically weigh the data.

In the end, this final approximation of the Atlantic Basin is probably too conservative (i.e., too narrow), and it likely underestimates the various relative energy proportions of the Atlantic (given that it excludes landlocked countries that might have access to — and active use of — Atlantic Basin ports). Such a conservative underestimation, however, is probably appropriate if we are to avoid generating premature enthusiasm or concern for the emergence of an Atlantic Basin energy system or excessive expectations of its imminent emergence, beyond what would be called for by a reasonably objective analysis.

1. An Introductory Exploration of the Atlantic Basin Energy System

1.1 The Atlantic Basin and “Atlantic Systems”

The Atlantic Ocean has long been the central crossroads of the Western world. Ever since Columbus landed at Hispaniola (the present-day Dominican Republic), a travel and trade axis has crossed the Atlantic from northeast (Europe) to southwest (Latin America and the Caribbean). As the Spanish and Portuguese colonized what is now Latin America, they generated a return flow of gold and silver. Soon thereafter, as Europeans exploited West Africa for its human labor, the slave trade opened a southeast–northwest axis, delivering human cargoes to the Caribbean and North American colonies. Sugar, rum, and cotton were carried back to Europe along another burgeoning trade route linking Europe in the Atlantic northeast with North America in the northwest. Textiles, arms, and ammunition were shipped back down to African slave traders and local overlords, deepening the northeast–southeast axis. Finally, a southeast–southwest corridor for transatlantic trade and human trafficking also emerged between current-day Brazil and the Gulf of Guinea.³

For 300 years, the Atlantic’s center of gravity remained somewhere between the Tropic of Cancer and the Equator. Lands on both sides of the southern Atlantic were key players in the emerging Atlantic system, even if the power vector ran clearly from north to south. Over time, as the Atlantic Basin became an increasingly integrated and unified economy (even if still essentially colonial), these economic and political connections became ever denser and more complex. By the 19th century, however, the center of gravity had begun to shift clearly northward as the British displaced the Spanish, Portuguese, Dutch, and French empires (all with many of their major colonies concentrated in the southern Atlantic), and as North America became a relatively more strategic economic partner for Europe. Northern trade, investment, and migration

³ See “Bridging the Atlantic: Brazil and Sub-Saharan Africa, South-South Partnering for Growth,” World Bank and IPEA, 2012.

connections linking the United States with Europe came to dominate the Atlantic space, and by the end of World War II, the term “transatlantic relationship” had come to signify, almost exclusively, the economic and political relationship between the United States and European powers. At best, Latin America and Africa served as footnotes to — or even as strategic targets within — the Northern conception of the Atlantic.

In recent years, however, the political cohesiveness of the “transatlantic community” has weakened considerably. The denouement of the Cold War and the unraveling of the Soviet empire loosened the links that once tightly bound the United States and Europe together at the geopolitical hip. Although the economic ties across the northern Atlantic still constitute the single most significant transcontinental economic linkage within the world economy,⁴ the globalizing shocks of the post-Cold War era have catalyzed a number of international shifts in relative power, issuing the first signs of a potential “crisis of the West.” In this context, the Atlantic Basin takes on new meaning as an analytical lens and strategic framework that emerging market countries in the southern Atlantic might leverage to improve their geopolitical flexibility and economic prospects. In the long run, the concept of the Atlantic Basin might even serve as an inspiration for a revived and transformed West, or for at least a reconfigured Atlantic space — perhaps, but not necessarily exclusively, through the expansion of the traditional, institutionalized U.S.–EU transatlantic relationship to include the participation of a broader Atlantic world.

With the coalescing of the BRICS countries (Brazil, Russia, India, China, and South Africa) and the emergence of a “global South consciousness,” not only has the northern Atlantic’s international preeminence increasingly become subject to global questioning — with the moral authority of the West never more in doubt — but so too has the West’s center of gravity, and dynamic internal composition, begun to shift once again, this time from north to south. More and more, the countries and peoples of the southern Atlantic are becoming relevant, if not central protagonists, in the

⁴ See Hamilton, Daniel S., and Quinlan, Joseph P., *The Transatlantic Economy 2011: Annual Survey of Jobs, Trade and Investment between the United States and Europe*, Washington, DC: Center for Transatlantic Relations, 2011.

structure and dynamics of geopolitics within the Atlantic space. Energy and climate issues in particular have become key Atlantic vectors, as the Atlantic Basin re-emerges as an important subsystem within the global political economy alongside the Pacific and Indian Ocean basin-systems. An incipient Atlantic Basin energy system may hold at least one of the keys to any such revival or reconfiguration of the Atlantic world.

Although some in the United States have advocated a return to the Pacific as the most effective posture for engaging — *or containing* — China, others have called for the seduction of Russia back into the Western fold as a key element in a strategy for dealing with the growing global South consciousness among the BRICS, by turning the old transatlantic relationship into a consolidation of the North.⁵ But the tired references to China and Russia might best be rejuvenated by a renewed focus on the West. In an age of instabilities and transitions in the northern Atlantic world, a broadening of the transatlantic relationship to embrace the energies and ambitions of the emerging, developing countries across the southern Atlantic might develop and consolidate a relatively liberal and democratic space — if the northern countries prove capable of creatively ceding portions of their influence to the large emerging countries in the South that have traditionally remained in the geopolitical shadows.

1.2 The Energy Map of the Atlantic Basin

1.2.1 Differentiation in the Atlantic Basin Energy Map

The energy map of the Atlantic world is one that reflects not only the very different real income and consumption levels of the four Atlantic continents, but also divergent energy economies as well as distinct and evolving energy policy environments. Nevertheless, global trends (climate change, intensifying competition for resources, and the imperative to eliminate poverty) are pushing, however hesitantly, in the direction of energy policy convergence within the Atlantic and toward a deepening of transatlantic energy trade and investment driven by comparative advantages, niche markets, technology transfer, and systems linkages.

⁵ See Zbigniew Brzezinski, “Balancing the East, Upgrading the West: U.S. Grand Strategy in an Age of Upheaval,” *Foreign Affairs*, January/February 2012.

In North America (where 24 percent of the world's primary energy is consumed in the United States alone), oil has long ruled the road (accounting for some 35 percent of the primary energy mix and well over 90 percent of transportation fuels). At the same time, coal has been king in factories and homes (20 percent of the primary mix and around half of the generation mix).⁶ Meanwhile, natural gas (currently 25 percent of the primary mix) could become the next energy king if the shale revolution survives, deepens, and spreads. Nuclear power (9 percent of the primary mix) has a significant role in the generation mix (accounting for 20 percent of electricity), although its future remains clouded in the wake of the nuclear disaster in Japan.⁷ Biofuels in the United States — mainly ethanol produced from corn — have been subsidized and protected, but they still account for less than 10 percent of all transportation fuels. Renewables in general are growing relatively fast, but from a negligible base and in a policy environment that has recently become hostile to — or at least uncertain for — future investment in renewable energies and other forms of low-carbon energy technologies.

Europe, on the other hand, consumes more oil (41 percent of the primary mix), the same proportion of gas (25 percent), less coal (16 percent), and more nuclear power (13 percent) — although the German government's recent decision to halt the expansion of the country's nuclear energy program, and to plan for the eventual decommissioning of all its nuclear plants, certainly casts a cloud of uncertainty over the future of nuclear energy in Europe, even as France recommits itself to dependence on nuclear power. Europe is also slightly more advanced — particularly among the continent's key Atlantic players such as Germany, Spain, the U.K., and Scandinavia — along the road to a renewable energy and low-

⁶ Due to the expanded production of shale gas in the past few years, coal's share of electricity generation in the United States has fallen to below 40 percent.

⁷ The energy mix figures in this section come from British Petroleum's *Statistical Review of World Energy 2011*.

carbon economy than is the United States and, for that matter, the rest of the Atlantic Basin.⁸

Latin America, for its part, is excessively dependent on oil (nearly half of the primary energy mix), but due to the region's relative lack of coal (only 4 percent) and nuclear power (less than 1 percent), hydroelectric power is more dominant here (more than 25 percent) than in any other part of the world, to say nothing of the Atlantic Basin.⁹ Latin America is also a leader in the biofuels terrain — particularly Brazil (where ethanol is produced relatively efficiently and cheaply from sugarcane), traditionally and still often the world's leading exporter of biofuels, if sometimes now slightly behind its Atlantic Basin ally and biofuels partner, the United States.

In Africa, meanwhile, traditional biomass still contributes a dominant share of the energy mix, and energy poverty registers its highest regional levels. Africa has the lowest electrification rate of all the world's regions — only 26 percent of households — leaving as many as 547 million people without access to electricity. Meanwhile, some 75 percent of Africans still depend on traditional biomass for cooking and heating.¹⁰ If the United States remains the fossil fuel center of the Atlantic Basin, Europe is the basin's leader in nuclear power and modern renewables, as is Latin America in hydropower and biofuels. For its part, Africa still looks to eliminate its energy poverty while reducing the carbon intensities of its smaller but growing energy economies. South Africa (a leader in synthetic transportation fuels) and Morocco (a pioneer among developing countries in modern renewable energies) are strategically well positioned to lead the way among the Atlantic countries of Africa.

⁸ The possible exception to this assertion, among significant players, would be Brazil, the country in the Atlantic Basin with the lowest percentage of fossil fuels in its total primary energy mix. While it is true that Brazil has more low-carbon energy sources in its primary mix than almost any other country, making it the “cleanest” country in the Basin, much of this is due to the high dependence on hydropower in the electricity mix (more than 80 percent). On the other hand, Brazil's largest contribution of greenhouse gas emissions stems from deforestation and changes in agricultural and land-use patterns and, as a result, does not appear in either the country's energy mix or in its “energy emissions profile.” See the section (3.1) on Brazil in Chapter Three.

⁹ In the rest of the Atlantic Basin (as in the rest of the world), hydroelectricity contributes only 5 percent to 6 percent of the primary energy mix, although it does have enormous theoretical potential in Africa.

¹⁰ “Africa Energy Poverty,” G8 Energy Ministers Meeting, Rome, May 24–25, 2009, World Bank, 2009.

1.2.2 A Southward Shift in the Gravitational Center of the Atlantic Basin Energy Map

The shifting energy landscape of the Atlantic Basin also reveals relative movement in the center of gravity for both energy demand and supply from economies in the north, in general, down to economies farther south. In 2005 the southern Atlantic accounted for less than 17 percent of total Atlantic Basin energy demand; by 2035 the southern Atlantic's share will have risen to 25 percent, even as total basin demand rises 30 percent over the same time period (see Figure 1). Although Europe and the United States remain the dominant energy players within the Atlantic world, other countries are becoming increasingly significant in relative terms. The Southern Cone and Southern Africa have recently emerged as new centers of gravity within the energy landscape of the Atlantic Basin. In the Western world, at least, it is in these regions of the southern Atlantic where most of the new energy trends are now emerging with the most force and the greatest potential for transformation. If these trends are not yet generating a new Atlantic energy system, then they are certainly laying much of the groundwork for such a system to emerge in an identifiable and useful form in the future.

The most recent and dynamic energy trends are continuing to find more space for development within the southern Atlantic. Such trends include deep offshore oil production, liquefied natural gas (LNG), unconventional (shale and tight) gas, new techniques for synthetic fuels production (gas-to-liquids and coal-to-liquids), and cleaner fossil fuel technology (carbon capture and sequestration, and other clean coal technology), along with traditional (hydropower) and modern renewable energies (wind, solar, geothermal, and tidal power).

South Africa and Brazil (and also, though to a lesser extent, Morocco and Argentina) are now essential case studies within the Atlantic energy space. These countries have developed energy strategies in which many of these same new trends have become central drivers for national development and are key variables in the articulation of their national energy policies — far more so than is the case in the United States, or even in Europe. In many ways, these emerging market powers have become the new energy pioneers of the Atlantic world.

1.3 Preconditions for the Emergence of an Atlantic Basin Energy System

An Atlantic Basin energy system, per se, does not yet exist. At present it can only be abstracted from the many overlapping subsets of the global energy system. No formal or informal Atlantic energy organizations currently exist, with the exception of the relatively inactive EU-U.S. Energy Council, a strictly northern Atlantic institution embedded within the U.S.–EU Summit framework. There is still nothing yet anything like an Atlantic Basin consciousness, and only a few policy thinkers have begun to pioneer the concept.

Nevertheless, certain prototype Atlantic “subsystems” already do exist, in the form of regional Atlantic Basin markets for crude oil, LNG, coal, and petroleum-derivative products (gasoline, diesel, etc.) — even in the face of the increasingly globalized dynamics of these markets. Furthermore, most of the preconditions necessary for these subsystems to coalesce into a new Atlantic Basin energy system are either already in place or now emerging. However, certain other important preconditions (particularly those concerning governance, however shallow or informal) are not yet fully in place within the Atlantic world.

An Atlantic Basin energy system could not meaningfully exist without exhibiting a minimally sufficient degree of breadth and depth in its intrabasin energy interactions — both in absolute terms, and relative to the global system (e.g., the global petroleum market) and the other significant subsystems (such as the Indian Ocean basin and Pacific Rim energy systems). To consider the potential evolution of an Atlantic Basin energy system in the near or midterm future would necessarily presuppose:

- relatively high and/or rising levels of energy demand within the basin;
- relatively high and/or rising levels of energy supply within the basin;
- a relatively high and intensifying degree of independence and autonomy with respect to the extra-Atlantic world; and

- a sufficient degree of geographic complementarity within the basin in terms of supply options, demand preferences, and investment needs (in order to ensure that most of the basin's supply can potentially be deployed to meet most of its demand), opening up the possibility for a progressive deepening of the system's density and relative autonomy (two of the most defining traits for any system).

In addition to such “endogenous” considerations, a number of other “exogenous” factors could either facilitate or hold back the development of an Atlantic Basin energy “space” into an identifiable, meaningful, and sustainable “system.” Exogenous factors like these are often instrumental in allowing for such a system to become more voluminous as well as denser in the networked complexity of its interactions. Increased volume and heightened density of interaction would give rise to more practical economic and security needs — and therefore more demand — for tighter policy coordination and more intensive diplomacy within the Atlantic space. Heightened demand for policy coordination and Atlantic Basin diplomacy would, in turn, generate the possibility for a regional Atlantic Basin “consciousness” to form and grow. Finally, with the emergence of such a regional basin consciousness — however fragmented and initially incomplete — would come the eventual possibility of girding the energy “system,” complete with its market and technological components, within a functioning (even if informal or shallow) “governance space,” allowing the system's independent actors to secure the maximum overall economic and political benefits.

Key exogenous influences on an emerging system would include:

- the fate of financial and fiscal stabilization in the northern Atlantic, and eventual recovery of stable economic growth rates in the United States and the EU (so as to ensure sufficient financing for investment in new energy supply from within the basin);
- energy and carbon prices high enough to encourage a change in the quality (clean versus dirty, autochthonous versus imported) as well as the quantity (supply in relation to demand) of energy);

- further rationalization and reform of national and international energy and climate policies affecting the economies of the Atlantic Basin (in order to stimulate more cross-Atlantic energy investment and trade in both traditional and new energy sectors); and
- a potentially growing interest in the concept of the Atlantic Basin among both northern and southern Atlantic countries (albeit if, initially, for different political and economic motives) as a potential market with its own technological, diplomatic, and even regulatory frame of reference.

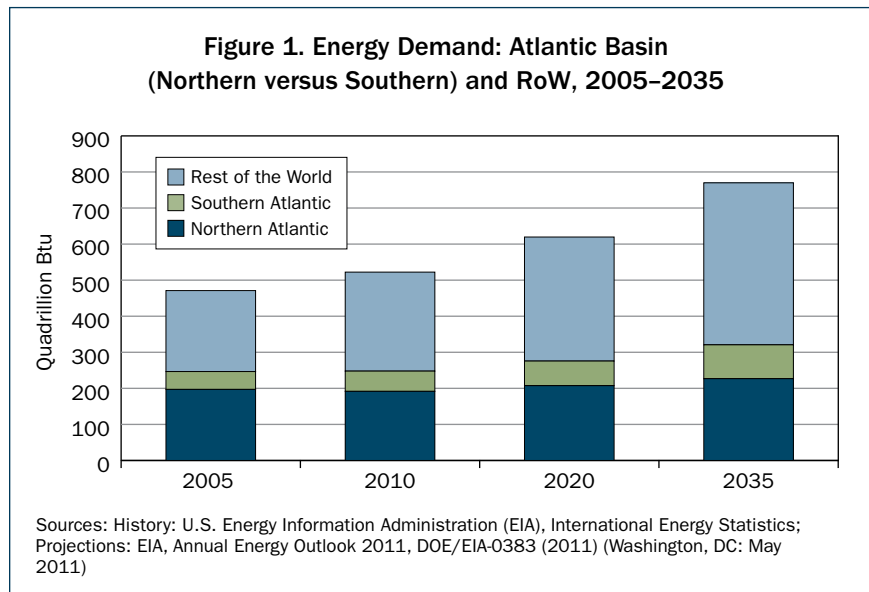
Indeed, the Atlantic Basin could turn out to be the ideal space within which the Atlantic's many energy economies begin to abandon the chimera of "national energy independence" and pursue instead — through a conscious framing of energy policy and a deliberate recasting of energy relations within the basin — an ultimately more sustainable, and therefore pragmatic, "collective energy security."

1.3.1 Rising Energy Demand in the Atlantic Basin

The first necessary precondition for an Atlantic Basin energy system — and the one most clearly met — would be robust and rising energy demand in the Atlantic, underpinned by the strong expectation that it will be sustained into the future. At the global level, this is indeed the case. Energy demand in the developing world is expected to rise by 60 percent through 2035, whereas demand growth is projected to be much flatter (0.6 percent annually) within the OECD. Although demand from developing Asia is set to grow at 2.9 percent annually to 2035 — far faster than anywhere else — the southern Atlantic continents of Africa and Latin America are projected to experience rising average annual energy demand of 1.8 percent and 2 percent, respectively — far above the anemic demand growth expected from the northern Atlantic (0.5 percent).¹¹ Total Atlantic Basin energy demand is expected to rise by 30 percent to 2035 — even as northern Atlantic demand grows by only 15 percent (compared to a full doubling of demand in the rest of the world) — with the entire Atlantic Basin still contributing 42 percent of global energy demand by

¹¹ U.S. Energy Information Administration (EIA), *International Energy Outlook 2011*, EIA, Washington, DC, 2011.

2035. However, the southern Atlantic alone is projected to increase its share of Atlantic Basin energy demand from 20 percent to 30 percent, and its share of total world energy demand from 10 percent to 12 percent. Not only will this expected boom in southern Atlantic energy demand lend the Atlantic Basin energy space vital critical mass within the global energy system; but also it signals a real need for an Atlantic Basin energy system capable of generating and channeling unprecedented amounts of energy and climate investment so as to ultimately bring forth sufficient supply.



The supply-side investment required to meet this projected demand in the developing world is estimated by the IEA at \$800 billion annually for the next 25 years. Additional investment of \$41 billion to \$77 billion and \$90 billion, respectively, will also be required annually if the world is to finally tackle its modern energy poverty and to achieve both goals in a sufficiently low-carbon manner.¹² Anywhere between 30 percent and 40 percent of this \$1 trillion of potential annual energy and low-carbon investment (some \$350 billion annually) could reasonably be expected to occur (to the extent that it actually takes place) within the southern Atlantic. In other words, key forward-looking countries in the southern Atlantic (such as Morocco, Brazil, and South Africa) are now poised — as the potential recipients of enormous inflows of

¹² International Energy Agency, *World Energy Outlook 2010*, IEA, Paris, 2010.

foreign direct investment in traditional and new energy sectors — at the cusp of a potentially epoch-shaping transformation of the Atlantic Basin’s energy space, with enormous implications (opportunities, challenges, and threats) for the region’s economics and geopolitics.

1.3.2 An Atlantic Basin Supply-Side Boom

The second necessary precondition — a significant increase in the available energy supply of the Atlantic Basin — is also now being realized. In recent years, the supply-side energy picture of the Atlantic Basin has been transformed dramatically for the better, both in absolute terms and relative to Atlantic Basin energy consumption. Currently the Atlantic Basin accounts for approximately one-third of global oil and gas production. Meanwhile, more than 40 percent of world petroleum reserves and nearly 12 percent of global conventional gas reserves (according to our adjusted estimates, see Chapter Two) are located in the Atlantic world. These figures are also likely to rise in coming years, as more unconventional oil (Canadian tar sands and Venezuelan super-heavy oil), offshore oil (Brazilian, Argentine, Mexican, Cuban, and African oil, including pre-salt deposits on both side of the southern Atlantic), Arctic oil, and shale gas (especially in the United States, the Southern Cone, and South Africa) is discovered, classified as proven reserves, and eventually brought on line as new production.

The discovery and development of new oil and gas reserves up and down the Atlantic — along with the progressive transfer of new low-carbon technologies and large-scale development and rollout of renewable energy resources, from wind power to bioenergy — could significantly deepen and broaden the interactions underpinning the Atlantic energy markets. Already Brazilian pre-salt exploration has kicked off a deep offshore boom in the southern Atlantic — which has caught on in Angola and Ghana, and could also explode all along the West African Transform Margin — that could potentially coalesce into a southern Atlantic oil ring (see section 2.4.1 on the Upstream). This, in turn, could reduce the dependence of many Atlantic Basin countries on Eurasian energy sources, taking pressure off their intensifying competition with China and India (and with Russia, on the

upstream and midstream sides) over energy from the world's most unstable regions in the Middle East and Central Asia.

1.3.3 *The Relative Energy Autonomy of the Atlantic Basin*

The Atlantic Basin not only controls a relatively large share of a growing global energy supply, but also has an already voluminous and dense intra-area energy trade. Pure intra-Atlantic Basin trade takes up a relatively large share — around 30 percent — of both the global petroleum and liquefied natural gas markets, lending Atlantic Basin markets a certain level of depth and functional autonomy in relation to the overarching global markets. Furthermore, as a basin, the Atlantic is also relatively energy-independent. Given current production and consumption levels, only some 15 percent of Atlantic Basin petroleum consumption must be covered, in net terms, with interbasin imports from the extra-Atlantic world.¹³ A mere 6 percent of Atlantic Basin natural gas consumption must be met, in net terms, with interbasin imports from beyond the basin.¹⁴

Given its heavy weight in global energy markets, and considering the depth and coherence of the basin markets themselves, the Atlantic Basin now wields substantial critical mass in terms of global market and political influence in the realm of energy. Indeed, if energy and climate change continue to displace regional integration and free trade agreements on the global policy agenda — as they have for the last ten years — there could well be a resurgence of the geopolitical weight of the Atlantic Basin, based precisely on the size, depth, and dynamism of its internal energy markets. In any event, the growing density of the intra-Atlantic energy trade, combined with the boom in Atlantic energy supply,

¹³ Some 7.5mbd of 36mbd consumed, averaging the “broad” and “narrowest” categories of the Atlantic Basin. For a description of these definitional categories, see *Definitions and Conceptual Framework*.

¹⁴ This low level of external gas dependence for the Atlantic basin as a whole may strike some as surprising, given the prominent place Russian gas exports to Europe occupy in the popular imagination. While the 114bcm of piped gas imports from Russia to the EU represent 25 percent of European gas consumption, they represent only 7.6 percent of Atlantic Basin gas consumption, leaving the “broad” Atlantic dependent on extra-Atlantic gas imports for 8 percent to 9 percent of total Atlantic Basin consumption. The 6 percent figure in the text is an average of the “broad” and “narrowest” categories of the Atlantic Basin. For a description of these definitional categories, see *Definitions and Conceptual Framework*.

suggests that an Atlantic Basin energy system might now exist at an incipient stage.

1.3.4 Sufficient Intrabasin Complementarity for Development of an Atlantic Energy System

The trends discussed above point in the direction of a fourth precondition necessary for the emergence of an Atlantic Basin energy system to emerge: the existence of mutually complementary opportunities to develop energy investment and trade linkages across the Atlantic, particularly in the southern Atlantic. A number of opportunities already exist — and others are in the process of materializing — for energy trade and investment collaboration across the southern Atlantic, and not just in the realm of offshore or otherwise “difficult” oil. Opportunities abound in sugarcane-based biofuels, shale gas development, gas-to-liquids production, hydropower, and modern renewables. Furthermore, a number of international finance mechanisms have recently been created to facilitate public and private investment in renewable energy and energy efficiency, and to roll out an increasingly low-carbon economy in the developing world.¹⁵ Although such mechanisms will likely channel financial flows from North to South — at least initially — it is also probable that eventually they will also stimulate flows from Latin America to Africa, and vice versa.

The energy complementarity of numerous Atlantic Basin countries and subregions, particularly in the southern Atlantic, has recently been revealed along the energy supply chain in various segments of the upstream, midstream, and downstream. One example is the complementary nature of potential Argentina shale gas (upstream) with existing South African gas-to-liquids (GTL) synthetic fuel technology (downstream). Another would be the opportunity for much denser, more efficiency-driven interpenetration among the energy service sectors within and across the Atlantic. Complementary opportunities also exist along the midstream — in the realm of LNG — and in the downstream — particularly with regard to investment and trade in the biofuels sector between Brazil and the Atlantic countries of West and Southern Africa, and in

¹⁵ These include, among others, the World Bank’s Clean Technology Fund, Strategic Climate Fund, Scaling Up Renewable Energy Program in Low Income Countries, the UNDP’s UN-REDD Programme, and the various funds of the Global Environment Facility. For more, see <http://www.climatefundsupdate.org/>.

the product markets for transportation fuels (between consumer and producer countries, along both North–South and South–South vectors).

Finally, potential complementarity also exists for profitable and productive investment in the realm of electricity generation from hydropower and other potentially low-carbon sources, transmission and distribution infrastructure (including the potential development of an electric vehicle industry in certain basin countries), international interconnections, and regional electricity market development. In fact, a number of subregional complementarities could potentially stimulate a broadening and deepening of international electricity integration around the Atlantic Basin. Any such development would serve as a powerful catalyst for the development of an Atlantic Basin energy system.

Examples in the electricity realm include complementarities between:

- Europe and North Africa, where massive solar potential — developed through either the EU’s MedSolar project or the private sector’s DESERTEC — could be combined with investment in a “Mediterranean electricity ring” to help resolve both energy security and climate challenges in this corner of the broad Atlantic Basin.
- The countries of Central America, where a successful future for the SIEPAC regional electricity system could potentially open the door — through the eventual inclusion of Mexico and Colombia into the region’s growing chain of international interconnections — to a partial electricity integration of North and South America.
- North America and the island nations of the Caribbean, where investment has already been made into an embryonic network of international interconnections through large capacity subsea cables.
- The nations of Central and Southern Africa, where the potential combination of the nascent Southern African Power Pool with the enormous hydro potential of the Congo River Basin could ultimately transform the electricity supply situation for a large part of sub-Saharan Africa, a development that would

certainly facilitate Africa's goal of eliminating energy poverty without significantly contributing to future accumulations of greenhouse gases.

A surge in transnational energy-related investment within the Atlantic world, led by an expansion and deepening of intrabasin energy trade, also has the potential to tip the balance of energy geopolitics back in favor of “the West,” while at the same time significantly reducing the basin's carbon footprint. However, this would have to be a “new energy West,” increasingly influenced and shaped not just by the traditional northern Transatlantic powers (the United States and the EU) but also by the emerging powers of the southern Atlantic (Brazil and South Africa). Such a potential development would also facilitate the efforts of many southern Atlantic countries to wean themselves off the lower-value-added portion of the energy supply chain (crude oil and ethanol feedstock, for example) and even to export, potentially, a whole range of petroleum, bioenergy, and synthetic fuel products — particularly in the light-distillate realm — first to the Atlantic Basin, and then to the global market.

Given the energy issue's centrality — and its interlocking relationship with other key world challenges, such as poverty and climate change — it is poised to become the crucial trade and investment axis upon which a new Atlantic Basin energy system might take shape out of the current Atlantic space. Should this occur, other forms of trade and investment would likely be stimulated as well. These would have the effect of deepening political and cultural linkages across new vectors of the Atlantic, and adding further to the economic volumes and political weight of ever-growing South–South southern Atlantic interaction as well as to the real potential for a more comprehensive form of Atlantic Basin cooperation to emerge.

1.3.5 Currently Unmet Preconditions and Other Key External Influences

A number of other necessary factors — for the most part, exogenous to the functioning of the Atlantic Basin's nascent system — are not yet in place and therefore continue to function as a drag upon the development of an Atlantic Basin energy system.

First, although growth in the southern Atlantic remained remarkably strong in the face of the global financial crisis of 2008 and the subsequent global recession, a notable slowdown now appears likely. Although some private energy investment continued to flow from North to South even during the recession (attracted by relatively strong returns in the emerging markets), the continuing economic crisis of the northern Atlantic will eventually make itself felt around the basin. Until the global economy experiences a sustained recovery, North–South and South–South energy trade and investment flows are likely to be significantly weaker than otherwise could be the case.

A second key factor will be the evolution of global energy and carbon prices, which will function as either a catalyst for or a brake upon further dynamism within the Atlantic energy space. Energy and carbon prices will need to be high enough to stimulate: 1) sufficient investment (\$800 billion annually, according to the IEA) for supply to continue to meet growth-driven increases in energy demand; and 2) the additional investment needed (\$90 billion annually) to check developing world carbon emissions sufficiently to avoid breaching the 2 degree Celsius temperature increase limit posited by the United Nations Framework Convention on Climate Change (UNFCCC).

The long-term price trend is clearly upward. With global oil prices hovering around \$100/bbl today, the IEA now projects that prices will average \$103/bbl through the midterm to 2015, rising to \$133/bbl by 2035. In recent years, coal prices have risen just as dramatically as have those of oil, and along a similarly volatile pattern. Given coal's still large contribution to the global energy mix — but particularly to the Asian economies, where energy demand is growing fastest — coal prices in all probability will remain strong. Gas prices have moderated considerably, particularly in the Atlantic Basin, but only as a result of the shale gas revolution in the United States — in part stimulated by historically high gas prices previously — which has significantly eroded the once-tight link between oil and gas prices.

The quantity (i.e., production levels) and quality (i.e., carbon content) of the supply-side response to these rising energy price expectations have also evolved generally as expected, only this

response has not been nearly as dynamic or as broadly distributed as would be required to meet the energy-poverty-climate challenge effectively. The quadrupling of the world oil price over the last decade has led to an incipient hydrocarbons boom in the Atlantic Basin, while at the same time contributing significantly to the first true global blossoming of renewable energies. Although subsidies and other fiscal incentives as well as price supports have played a large role in stimulating renewable energies, the unfolding global renewables rollout (with its step-jump in scale) has itself contributed significantly to falling break-even prices for most forms of renewable energy. Nevertheless, this decline in production costs has not yet been steep enough to close the cost gap with fossil fuel competitors.

Over the last decade, carbon prices have taken shape with the creation of carbon markets in Europe (ETS) and the United States (the Northeast and Midwest regional markets) and through the growing use of international carbon offsets. Although the ETS carbon price (for the moment, the most significant international reference) has been generally weak to date (\$10–\$20/ton), it is expected to be \$20–\$30/ton over the coming years, with little but upside potential feasible into the future, given that the very real constraints of carbon-induced climate change will continue to impose themselves.

But if energy and carbon prices tend to be volatile over the short run, long-run price projections can also be deceptive — and volatile, plagued as they are by extremely high levels of uncertainty. Oil and gas companies tend to set their long-run price projections — which act as their internal threshold for triggering new investment — relatively conservatively, as do the principal net exporters (only not quite as much) when establishing the projected oil price as a central criterion for their national budgets. Furthermore, the global energy and carbon markets are almost

completely unregulated, insufficiently taxed, and even heavily and widely subsidized (on both the supply and demand sides).¹⁶

With such volatile and unpredictable energy prices — and with the price elasticities of both total energy supply and low-carbon energy supply remaining far too weak — it is difficult to maintain confidence that the new, higher price reality (even if it remains stable) will on its own bring forth sufficient investment in energy supply expansion, to say nothing of investment for lower global carbon intensity. What is missing in the Atlantic Basin is necessary state action, coordinated to a sufficient degree internationally, to facilitate a more rapid and complete reduction in the cost gap between fossil fuels and lower-carbon energy alternatives.

Higher taxes on fossil fuel energies and significant reductions in state subsidies to fossil fuel production and consumption will be required if the end prices of lower-carbon energy sources are to compete more effectively with those of fossil fuels. Far more and more robust regional carbon markets will also be required if average global carbon prices are to be sufficiently high and stable enough to eliminate the rest of this gap (that which is represented by the avoided costs that fossil fuel producers still “externalize” in the form of unregulated and unpaid-for carbon emissions). Given that upward pressures are most likely to remain strong over the long run, energy prices will continue to serve as a partial and limited driver of expanded and lower-carbon energy supply in the Atlantic Basin. However, the supply and quality response — a key precondition for the emergence of an Atlantic Basin energy system — would be strengthened considerably by the progressive elimination of state-induced distortions to the price of energy and carbon and by the creation of rigorous carbon markets.

Yet another obstacle currently holding back the emergence of an Atlantic Basin energy system is the relatively underdeveloped state of energy policies and regulatory regimes in the region (the EU being the clearest exception). Although this is changing in

¹⁶ The IEA claims that subsidies to support fossil fuel production and consumption totaled \$312 billion in 2009 — even after a previous decline provoked by some initial subsidy reductions in developing Asia before the outbreak of the global economic crisis. This level of global fossil fuel subsidies represents a whopping one-third of the investment required by the developing world alone to continue their economic growth, eliminate their energy poverty, and moderate their carbon footprint enough, as a group, to maintain emissions levels consistent with a global solution to the climate challenge.

most parts of the Atlantic Basin (as in Brazil, South Africa, and Morocco, for example), there are a few notable cases in which weak state institutions or corruption undermine the energy policies and regulatory regimes that do exist (as in Nigeria), or where energy nationalism continues to distort national energy policy altogether (Venezuela and, to a lesser degree, Argentina). However, even in most of the other countries of the Atlantic Basin (from the small developing countries of Atlantic Africa to the United States itself), policy and regulatory frameworks need to be strengthened, rationalized, and more closely coordinated. An Atlantic Basin energy system will have a difficult time taking shape if nationalist energy policies and competing and internally inconsistent regulatory regimes continue to weaken potential energy supply, distort the functioning of the Atlantic Basin regional energy markets, and block the emergence of an Atlantic Basin consciousness.

A fourth barrier to the emergence of such an Atlantic energy system is the absence of a diplomatic or governance framework of international relations within the Atlantic Basin resilient enough to sustain the shift of relative power from North to South currently under way, while still developing and deepening the Atlantic system. The Atlantic has no equivalent of the Pacific Rim's APEC or the now moribund Energy Charter Treaty in Europe and Eurasia. Today's politically dominant Atlantic frameworks — such as NATO and the U.S.–EU Summit relationship — essentially embrace only the northern Atlantic, whereas existing North–South Atlantic frameworks such as the Iberoamerican Community of Nations and the EU–Latin America Summit relationship are currently stalled or in a chronic state of crisis. Incipient southern Atlantic frameworks, such as South Atlantic Maritime Area Coordination and the South Atlantic Peace and Cooperation Zone, remain relatively underdeveloped.¹⁷ Nor does this nascent South–South cooperation in the southern Atlantic suggest that there is sufficient inclination to embrace more formal cooperation across the entire Atlantic Basin as an alternative to pursuing a more limited southern

¹⁷ “The ZPCSA was an important instrument which contributed to the political approximation of Africa and South American countries with two important results: The South America-African Nations Summit in 2006 and the establishment of the India, Brazil and South Africa Forum Dialogue in 2003.” INSouth: Intellectual Network of the South (http://www.insouth.org/index.php?option=com_sobi2&sobi2Task=sobi2Details&sobi2Id=20&Itemid=68)

Atlantic regionalism. On the contrary, some have even aspired to develop such incipient regionalism into a formal South Atlantic rim community, at least in the areas of maritime collaboration.¹⁸

Developing an Atlantic Basin energy system would certainly require overcoming the political and ideological impasse that still tends to separate the northern from the southern Atlantic. A lingering chauvinistic mind-set in the North continues to interact with the traditional perspective of the “colonized,” still pervasive in the South, to generate a rhetorical symbiosis between northern Atlantic condescension toward the South and southern Atlantic suspicion of the actions and motives of the North. For this reason, further development of an Atlantic Basin energy system would probably also require the articulation of at least a proto-Atlantic Basin consciousness, particularly within the southern Atlantic.

Figure 2. Preconditions for the Emergence of an Atlantic Basin Energy System

Preconditions	Met/Unmet	Strong/medium/weak fulfillment or remaining barrier
Dynamic energy demand	Met	Medium
Dynamic energy supply	Met	Strong
Sufficient energy autonomy	Met	Medium-Strong
Intrabasin complementarity	Met	Strong
Financial and economic stability in the northern Atlantic	Unmet	Weak-Medium
Appropriate pricing environment	Unmet	Medium-Strong
Stable and rigorous policy and regulatory environments	Unmet	Medium-Strong
Diplomatic/governance structure	Unmet	Medium-Strong

Source: The author's own elaboration.

1.4 An Atlantic Basin Consciousness and the Role of Energy

Nothing even close to an Atlantic Basin consciousness yet exists. Indeed, the major emerging countries of the southern Atlantic have tended to identify with the budding consciousness of the global South, and that of other South–South groupings, such

¹⁸ See Greg Mills, “South African-Latin American Maritime Cooperation: Towards a South Atlantic RIM Community?” *Diplomats and Defenders*, Monograph No. 9, Institute for Security Studies, Johannesburg, Feb. 1997.

as the BRICS (Brazil, Russia, India, China, and South Africa) or the trilateral IBSA relationship between India, South Africa, and Brazil.¹⁹ Nevertheless, although global South identities and loyalties may generate some initial resistance to the Atlantic Basin concept, it is also just as likely that the key emerging countries of the southern Atlantic will identify the Atlantic Basin as a useful diplomatic device for modifying strategic identities and moderating geopolitical dependencies and vulnerabilities deriving from previously articulated economic, political, and energy relationships with other traditional or rising powers beyond the Atlantic (such as the Arab and Muslim worlds, as in the case of Morocco; China, in the case of Brazil and West Africa; and the Indian Ocean Basin itself, in the case of South Africa). Such a pragmatic engagement of the Atlantic Basin — demonstrating clear marginal geopolitical value added — could go far in underpinning a nascent Atlantic Basin consciousness.

Even more crucially, the discovery and development of substantial new energy resources in the Atlantic Basin could significantly reduce crucial strategic Atlantic Basin interests in the Middle East and the Caspian region, leaving China, India, and Russia to sort out the geopolitical headache of the “new Great Game” increasingly on their own. To be sure, as soon as even a proto-Atlantic Basin energy system begins to deliver such energy security and other environmental and development benefits, a nascent Atlantic Basin consciousness could emerge and begin to spread.

For the moment, however, a number of barriers continue to undermine the development of any such Atlantic Basin consciousness. First, energy nationalism in energy-exporting countries tends to block the development of any consciousness that would incorporate the interests of both producer and consumer states. Energy nationalism could ebb again if prices adjust downward over the midterm (unlikely) or if a double-dip global recession plunges oil prices down once again to anywhere below the \$70/bbl mark, at least for some time. A recession-induced oil price plunge might even deliver a mortal blow to energy nationalism in unstable, imprudent, or maverick energy-exporting states (such as Venezuela, Nigeria, or even Russia) that are not as liquid or

¹⁹ See Joseph Senona, “BRIC and IBSA Forums: Neo-liberals in Disguise or Champions of the South?” SAIIA Policy Briefing, No 24, September 2010

solvent as some other countries (Saudi Arabia, for example) that might be able to withstand the pressures of price volatility with their nationalist energy policies more or less intact. Entrenching energy nationalism still further on the producer side, however, has been the demonstration of nationalist impulses in the energy policy evolution of the advanced net-importing economies.

A number of other factors reinforce the current dominance of energy nationalism over any policy posture that embraces open and inclusive transnational collaboration or that could ultimately aspire to the pooling — however superficial and limited — of energy sovereignty or even just energy security. A number of key energy actors in the Atlantic Basin (and particularly in the southern Atlantic, including Venezuela, Brazil, Argentina, South Africa, Angola, and Nigeria, to name the largest and most influential) already have competing loyalties to other political, economic, and diplomatic groupings (OPEC, the global South, the BRICS, the trilateral IBSA relationship, the Group of 77, etc.). Yet any geopolitical inclination these southern Atlantic actors might harbor to integrate into overlapping or compatible energy systems (for example, the strategic “hedging” option mentioned above) is further undermined by their relative lack of the critical human resources necessary for effectively engaging even the nascent basin systems that do already exist (for example, bottlenecks in Brazil’s equipment and services sectors), let alone for further participation in the creation and operation of new systems.

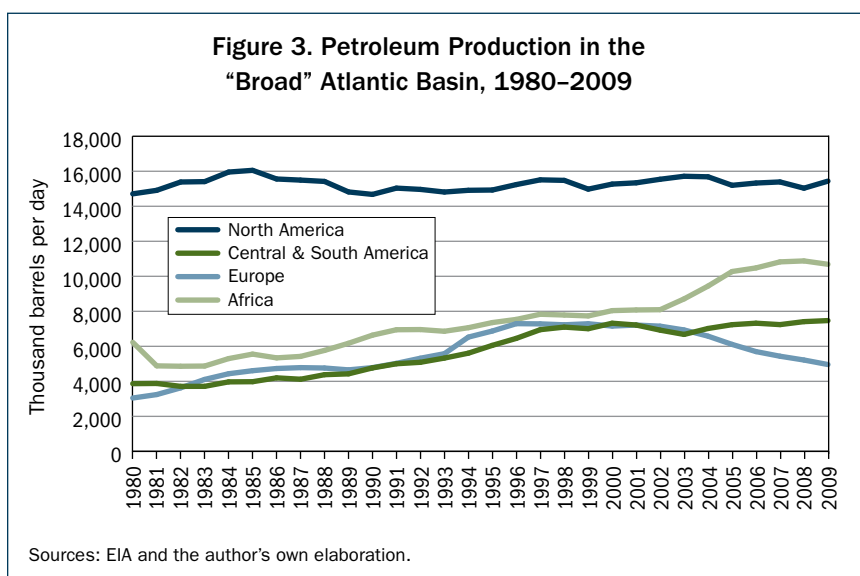
However, the potential strategic advantages in terms of energy, economic, and political security, of pursuing an Atlantic Basin strategy are clear: 1) a heightened relative geopolitical autonomy through geopolitical hedging and increased political and economic flexibility in relation to the extra-Atlantic world; and 2) a strong stimulus for low-carbon transformation and the reduction of energy poverty. With time, these advantages are likely to become even clearer. Given the favorable attention that the incipient notion of an Atlantic Basin has received in recent years from many actors around the Atlantic (including the United States, Morocco, Spain, and Brazil) and from among a growing, if still limited, number of policy thinkers, it is plausible that an Atlantic Basin consciousness could begin to take shape over the course of the midterm future.

2. The Shifting Energy Landscape of the Atlantic Basin

2.1 Atlantic Basin Oil

2.1.1 Production, Consumption, Imports, and Intra-basin Trade

For comparative purposes, we will use both the broad definition of the Atlantic Basin and the narrow definition.²⁰ Starting with an analysis of the upstream (see Figure 1), it can be seen that the broad Atlantic Basin produces collectively some 38mbd (2009), more than 40 percent of total world production of crude oil (see Figure 3).²¹

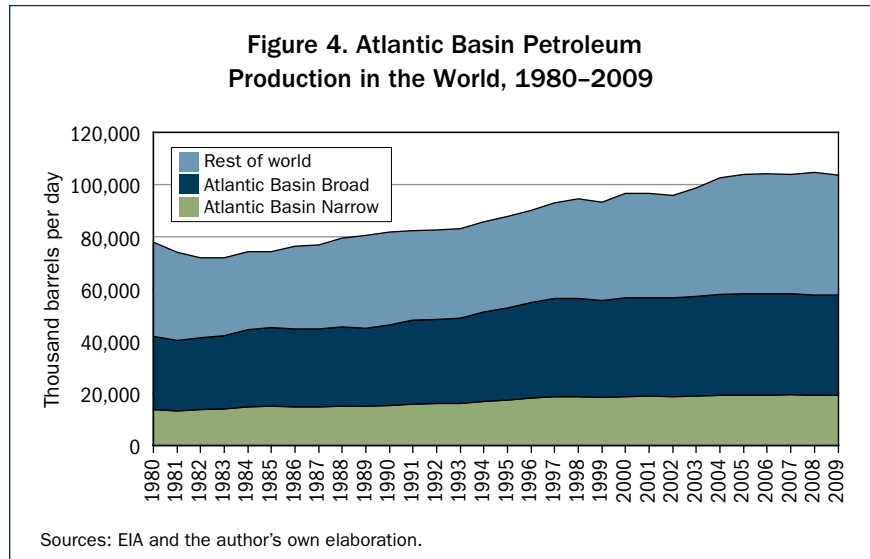


However, the narrow interpretation of the Atlantic Basin yields a much lower figure, once non-Atlantic countries are excluded from the sums and dual-basin figures are adjusted: 19.5mbd, equivalent to nearly one-quarter of total output. Given the inherent limitations of these two corner definitions of the Atlantic Basin, and short of access to exact geographic export-import flow data from all countries in the Atlantic Basin, about one-third of the world's

²⁰ See the section on Definitions and Conceptual Framework, following the Preface.

²¹ Until otherwise explicitly stated or noted, oil and gas figures are from the U.S. Department of Energy's Energy Information Administration (EIA) database. The graphs are based on the author's own elaborations of such figures as they appeared in the database as of November 2011. During the period of editorial revision and publication layout of this analysis, the EIA has updated such figures and added the years 2010 and 2011.

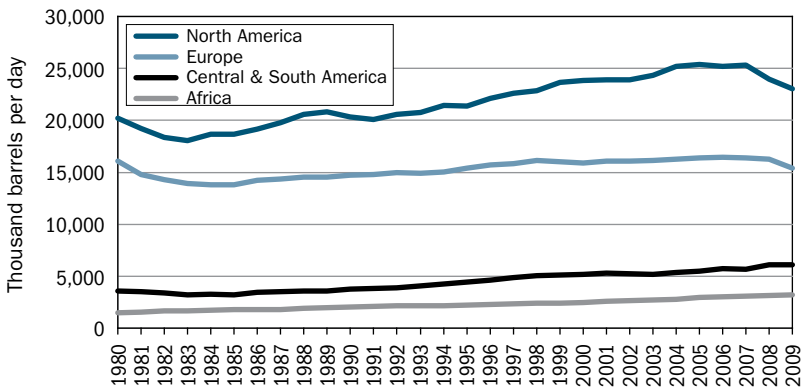
current oil production could realistically be said to currently come from the Atlantic world (see Figure 4).



In terms of consumption, the “broad” Atlantic Basin consumed 48mbd of petroleum in 2009 (or nearly 60 percent of the world daily total), whereas the narrowest version of the Atlantic Basin consumed just 24mbd (or not quite 30 percent of the world total). Some 20 percent of the “broad” Atlantic’s petroleum consumption needs must be met by net imports from the extra-Atlantic world (approximately 10mbd). Slightly more than 10 percent of the consumption needs of the “narrow” Atlantic must be imported (approximately 5mbd). We therefore can assume that, in net terms, approximately 15 percent of Atlantic Basin petroleum consumption must be met with interbasin imports from the extra-Atlantic world (about 7.5mbd of 36mbd of consumption, averaging the “broad” and the “narrow”).²²

²² It should be underlined that Atlantic Basin import dependence on the extra-Atlantic world is this study’s estimate, based on the criteria used for the “narrow” definition of the Atlantic Basin and publicly available data. It has not been verified by documented data on actual flows, which are typically not available from public sources. However, this study would argue that any difference between the “approximate” Atlantic Basin (a simple average of the “broad” and “narrow” definitions described above) and the most precise possible measurement would be very minor. For the purposes of this level of strategic analysis, this “approximate” Atlantic Basin should more than suffice.

**Figure 5. Petroleum Consumption
in the “Broad” Atlantic Basin, 1980–2009**



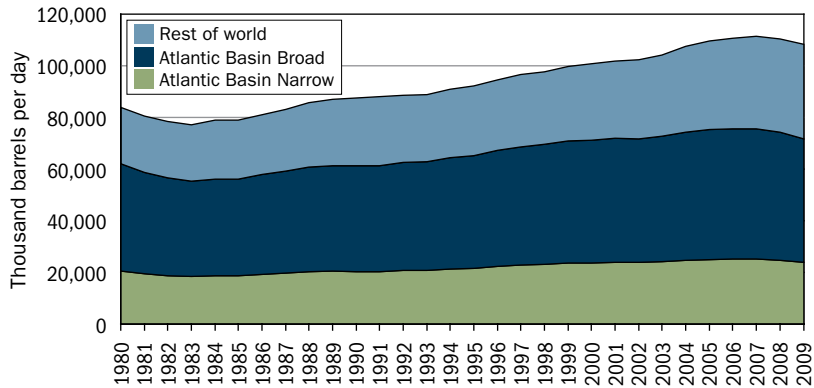
Sources: EIA and the author's own elaboration.

Of the 84mbd of oil produced globally in 2009, 53mbd were traded internationally. Nearly 14mbd, or some 25 percent, of this global market was pure Atlantic Basin trade (oil originating and terminating within the Atlantic Basin). The largest part of the international oil trade is concentrated, however, in the pure Indian Ocean trade, and in the Indian–Pacific and Indian–Atlantic interbasin trades (in that order). Some 29mbd are traded exclusively beyond the Atlantic Basin, in the “extra-Atlantic.”²³ The pure Pacific Basin trade, however, along with the Pacific–Atlantic interbasin trade, is the most limited in scope.²⁴ Nevertheless, the Atlantic Basin’s total share of the world oil trade (pure and interbasin) is more than one-third. This near parity with the Indian Ocean basin oil trade (both in terms of volume and relative autonomy) could have enormous ramifications for both the commercial and military maritime security of the energy trade in

²³ To form an idea of how large is the “extra-Atlantic” petroleum trade, start with the 53mbd of global trade and subtract from it the 14mbd of pure Atlantic trade and the 10mbd of interbasin Atlantic imports. You are left with 29mbd of “extra-Atlantic oil trade” or more than 50 percent of the global oil market.

²⁴ The figures on intra- and interbasin oil trade are based on this author’s best estimates using intercountry data from British Petroleum’s Annual Energy Statistics, 2010 (2009 data). However, BP’s data does not specify which coasts are involved (and therefore which flows are purely Atlantic Basin, and which are not) in the intercountry oil trade. These estimates, while roughly accurate, involve the same potential structural weakness as the production and consumption estimates of the “narrow” Atlantic Basin. Nevertheless, the divergence between this study’s estimated figure and the actual figures is likely to be quite small in most cases.

Figure 6. Atlantic Basin Petroleum Consumption in the World, 1980–2009



Sources: EIA and author's own elaboration.

the Atlantic Basin, another important strategic vector that could contribute to the emergence of an Atlantic Basin energy system.

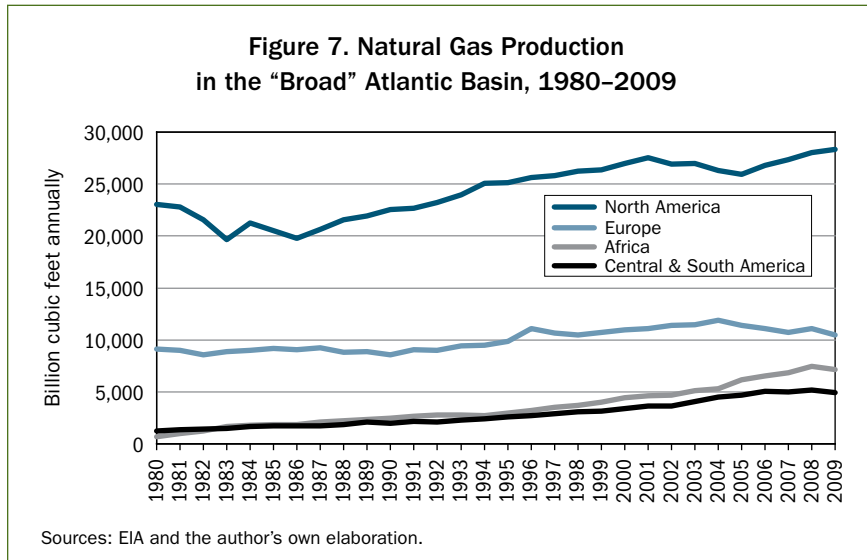
2.1.2 Oil Provides Critical Mass to the Atlantic Basin Energy Space

A central hypothesis of this analysis (which we will also test beyond the oil realm) is that whereas the Pacific Basin has gained in commercial and geopolitical significance since the 1980s (when energy receded from the strategic consciousness of the West after the energy shocks of the 1970s), the Atlantic Basin now wields a critical mass of influence within the global energy system. Critically, however, the Atlantic Basin has recently come to wield this influence on both the supply and demand sides, and in both conventional fossil fuel energy and modern renewables, exactly at the moment of maximum, if embattled, strategic concerns within the northern Atlantic for the economic, security, and environmental implications of energy. Indeed, if energy and climate change can continue to dominate the global agenda — as opposed to regional and global economic and financial integration, dynamics that prevailed over the political and economic agendas of the 1980s and 1990s — there could well be a resurgence of global geopolitical weight within the Atlantic Basin, despite the increasingly obvious structural weaknesses of the Atlantic world's *ancien régime* (i.e., the transatlantic system of the northern Atlantic).

On the other hand, the newly acquired, if incipient, structural advantages of the emerging powers of the southern Atlantic could potentially compensate for the increasingly apparent weaknesses of the North. Emerging players in the southern Atlantic, such as Brazil and South Africa, might also facilitate the emergence of an Atlantic Basin energy system, stimulate the formation of an Atlantic Basin consciousness, and catalyze an Atlantic resurgence in global geopolitical influence — or at least a rearticulation and renovation of the influence the West has long wielded, independent of the controversial and still open debate over possible recent “decline” in the North. Its sufficiently large weight (in terms of production and trade) within the current global oil system takes the basin a long way toward meeting the necessary preconditions for an Atlantic Basin energy system to emerge. Other aspects of the Atlantic Basin’s oil system — such as the ultimate size of basin oil reserves, the dynamic regional development of offshore oil, and the deepening development of the basin’s energy equipment and services sectors, with a clear specialization in the deep offshore — together with evolving dynamics in other energy realms (such as the strategically key gas sector, the biofuels sector, and the renewable energy realm) will only continue to augment the critical mass of a potential Atlantic Basin energy system.

2.2 Atlantic Basin Natural Gas

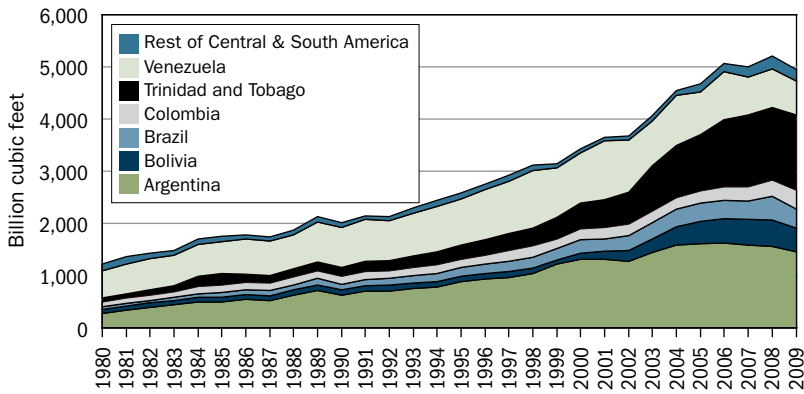
In the gas realm, nearly 51 trillion cubic feet of annual production comes from the “broad” Atlantic Basin (or some 140bcf per day), more than 48 percent of total world gas production. This figure is cut in half (to just over 25 trillion cubic feet annually, around 70bcf per day) when our “narrow” definition of the Atlantic Basin is applied. In other words, in terms of natural gas production (as with petroleum), the “broad” Atlantic Basin accounts for just under half of world production, whereas the “narrowest” accounts for around 25 percent, yielding a realistic estimate of more than one-third of global production — and this despite the significant concentration of conventional gas reserves in the Great Crescent of the Eurasian landmass (Europe’s long energy “backyard” that includes the Persian Gulf, Central Asia, and Russia), and the slow arrival of the shale gas revolution in Atlantic Basin beyond the United States.



The “broad” Atlantic Basin consumes 55.5tcf of gas annually (or 53 percent of total world gas consumption), leaving some 4.5tcf, in net terms, to be covered by extra-Atlantic imports (or about 12bcf per day, 140bcf per day produced minus 152bcf per day consumed), just over 8 percent of “broad” Atlantic Basin consumption needs (or 6 percent, averaging the broad and narrowest criteria). This makes extra-Atlantic gas import dependence in the Atlantic Basin roughly only 40 percent of the level (15%) of extra-Atlantic oil import dependence, even before considering the potential global shale gas revolution, which could potentially shift the Atlantic’s center of gravity, in terms of both reserves and production levels of natural gas, farther south.

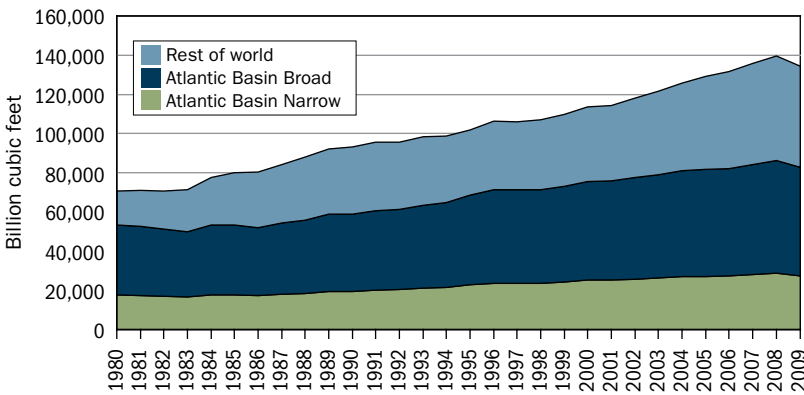
Again, although the extra-Atlantic world for years dominated the growing trade in LNG, in recent years the Atlantic Basin has been far more active in increasing its global share than either the Indian Ocean or the Pacific Basin (see the section on the Midstream). Although the extra-Atlantic world continues to dominate the gas world in absolute terms, the most recent trends reveal a resurgence of the relative power of the Atlantic Basin in the gas realm.

Figure 8. Natural Gas Production, Central and South America, 1980–2009



Sources: EIA and the author's own elaboration.

Figure 9. Atlantic Basin Gas Consumption in the World 1980–2009



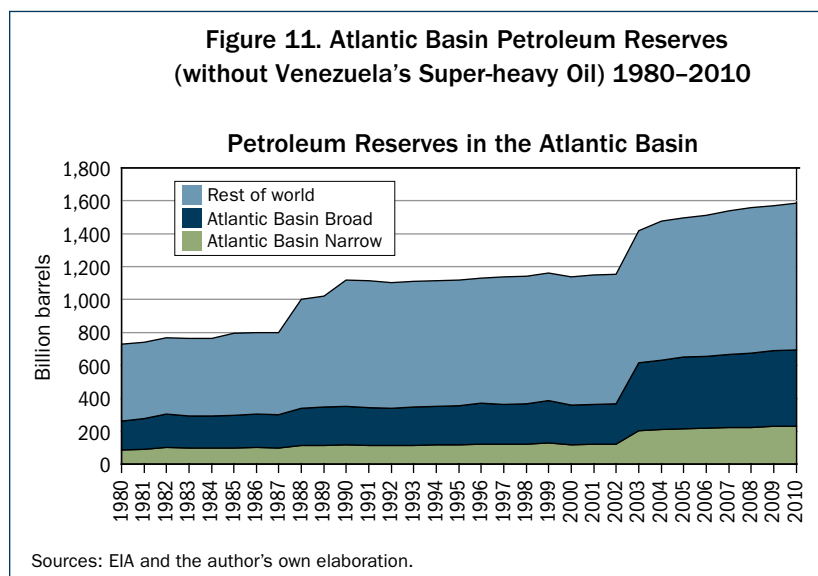
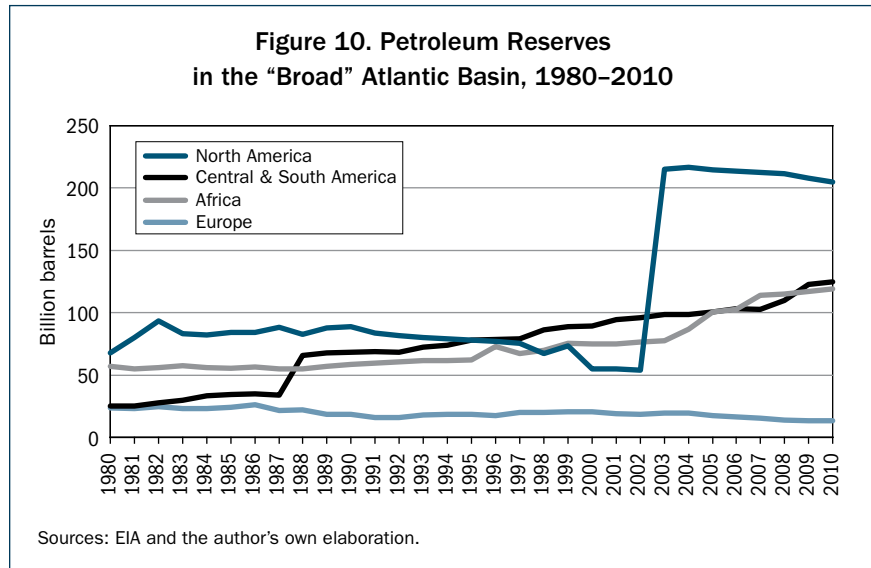
Sources: EIA and the author's own elaboration.

2.3 The Structure and Dynamics of the Atlantic Basin Hydrocarbons Map

2.3.1 The Oil Map

The largest oil producer in the Atlantic Basin — and also the basin's most voracious consumer — is the United States (7.2mbd produced in 2009, according to BP), followed by Canada (3.2mbd), Norway (2.3mbd), Nigeria (2.1mbd), Brazil (2.0mbd), Angola (1.8mbd), and the U.K. (1.5mbd), with Mexico (3.0mbd), Venezuela (2.4mbd),

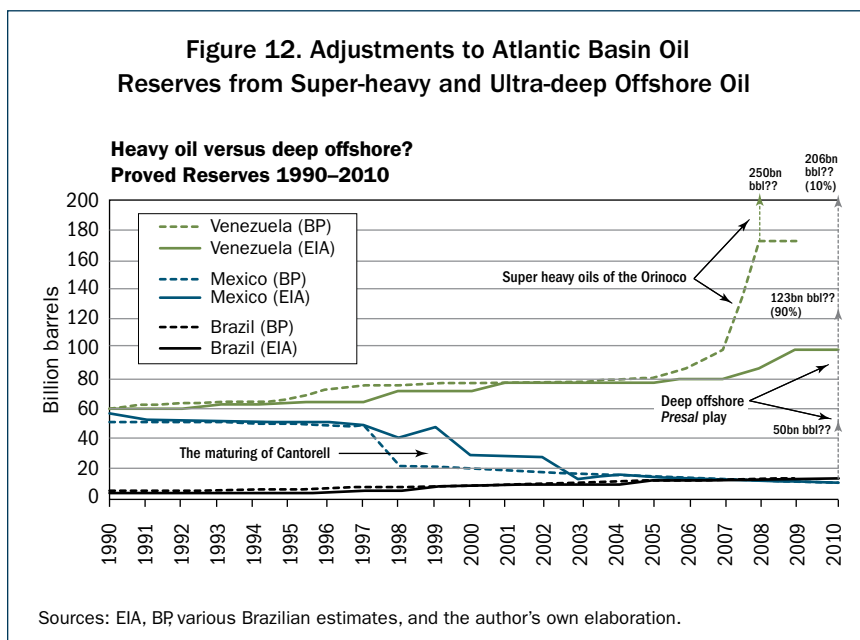
Colombia (685,000bd), Algeria, and Libya chipping in significant quantities from a “broad” Atlantic).²⁵ Nevertheless, the map changes when we shift to observing the relative reserve levels of petroleum for the producer states within the Atlantic (see Figure 10).



²⁵ These oil production figures come from BP’s Statistical Review of World Energy, 2010, and correspond to 2009. Since then, diverse data for 2010 shows that Brazil (2.5mbd) has overtaken Venezuela and Angola (2.0mbd) now produces more than Nigeria, just as Colombia (1mbd) has moved past Argentina. Excepting Canada and Norway, all the other significant oil producers of the Atlantic seem to be in decline, or at least on a long plateau of production stasis. Nevertheless, there are significant future prospects (see the section on the Upstream).

Figure 10 presents EIA data on petroleum reserves in the Atlantic Basin. At first glance, it reveals a story of traditional North American dominance temporarily lost during the 1990s but then recaptured dramatically early on during the past decade, with mildly increasing reserves in the southern Atlantic, all against a backdrop of longtime upstream irrelevance and stagnation in Europe (with the exception of Norway). Nevertheless, if we incorporate the most recent trends into the analysis, the picture transforms into something altogether different.

First, it is worth noting that the dramatic increase in reserves in North America in 2003 was due entirely to the official booking, as “proven reserves” by the EIA, of large quantities (more than 200 billion bbls) of “unconventional oil” — the bituminous sands in Canada (the “oil sands” or “tar sands” of Calgary). In theory, Canada’s unconventional oil is economically recoverable at prices above \$50–\$60/bbl. This inclusion of the oil sands in Canada’s official proven reserves, as recorded by the EIA, took the reserves of Canada from less than 5 billion bbl to more than 180 billion bbl overnight. On the other hand, the EIA figures *did not, at the time*, include the bulk of Venezuela’s unconventional oil (the “ultra-heavy oils” of the Orinoco Basin) in that country’s proven reserves calculations. Although Canada’s reserves grew to include much of the oil sands even before the significant price rise of 2004–2008, the EIA only increased



Venezuela's proven reserves by some 25 billion bbl (from 100 billion bbl in 2005 to 125 billion bbl in 2010). If a similar quantity of heavy oil were to be included in Venezuela's reserve figures, then the line representing Central and South America in Figure 10 would show a significant upward shift significantly for the past few years, bringing it close to North American reserve levels.²⁶

Secondly, the EIA calculates Brazil's reserves at no more than 12 billion bbl in 2010, despite the very large subsalt discoveries in the Campos and Santos basins in Brazil's deep offshore. However, most of the recent estimates coming out of Brazil now put the feasible reserve estimate at around 50 billion bbl — and often even well above 100 billion bbl — significantly altering the oil reserve picture around the Atlantic Basin. Indeed, the problems inherent in calculating unconventional and frontier sources of oil as “proven reserves” cloud the reserve picture in the Atlantic Basin even more (see Figure 12).

However, given that unconventional and frontier sources of oil are at the cutting edge of recent trends, it seems reasonable to adjust the center of gravity of oil reserves in the Atlantic Basin much farther south, and to modify upward this study's estimates of the Atlantic Basin's share in global oil reserves. If more optimistic local reserve estimates for Venezuela and Brazil are integrated with the EIA reserve estimates (with their generous categorization of Canada's oil sands), Atlantic Basin oil reserves would be as much as 300 billion barrels higher, accounting for more than 40 percent of global oil reserves. The basin's share in possible world oil reserves would likely rise even higher should we begin to consider the still unrevealed oil potential of Atlantic Africa, from Morocco through

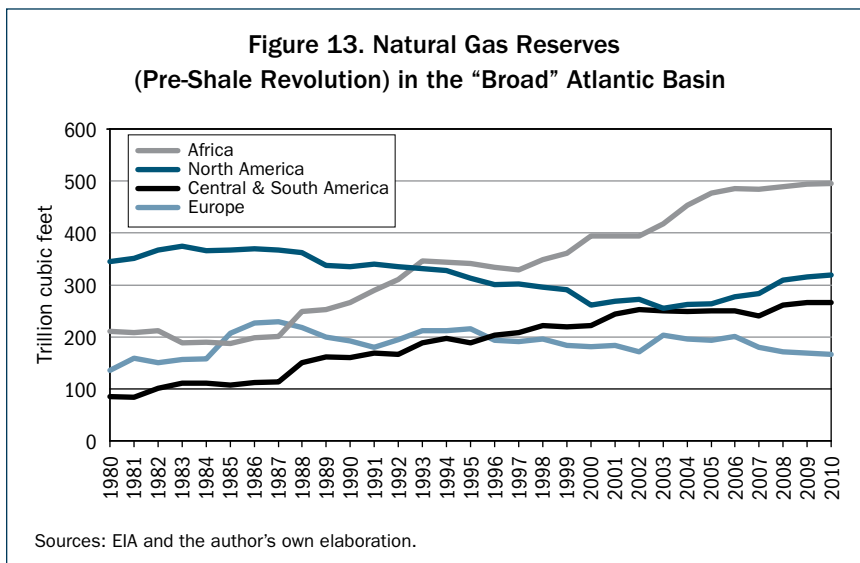
²⁶ In 2012, the EIA's database did upwardly revise Venezuela's reserve figures for the year 2011 (from 99 billion bbl to 211 billion bbl). For whatever reason, the EIA has tended to create a more favorable picture of Canada (a stable, friendly neighbor and close ally of the United States), and to downplay the oil potential from Venezuela, currently an aggressive, if not outright hostile, rival that has threatened to divert its 1mbd-plus export flow away from the United States to other markets, such as China. Examining the published reserve data of British Petroleum, whose *Annual Energy Statistics* database is widely used within the industry, the picture has long been very different. According to BP in 2010, Venezuela had 80 billion bbl of proven reserves in 2005; by 2009 nearly 100 billion bbl of ultra-heavy crude had been reclassified by BP as proven reserves, bringing the country's total to 172 billion bbl. On the other hand, Canada's proven reserves, according to BP in 2010, were a mere 17 billion bbl in 2005, and the figure rose only to 33 billion bbl by 2009. BP classified some 143 billion bbl of oil sands separately. This suggests that there is a very big discrepancy between U.S. and non-U.S. sources with respect to which of the two large reserves of unconventional oil in the Americas (Canada's sands versus Venezuela's Orinoco oils) is considered to be more feasibly recoverable in the future. Nevertheless, in 2012 BP's *Annual Energy Statistics* database revised upwards Canada's proven reserves over many of the past years to include a significant portion of the oil sands.

the West African Transform Margin to the Gulf of Guinea and Angola (see the section below on Hot New Hydrocarbon Zones).

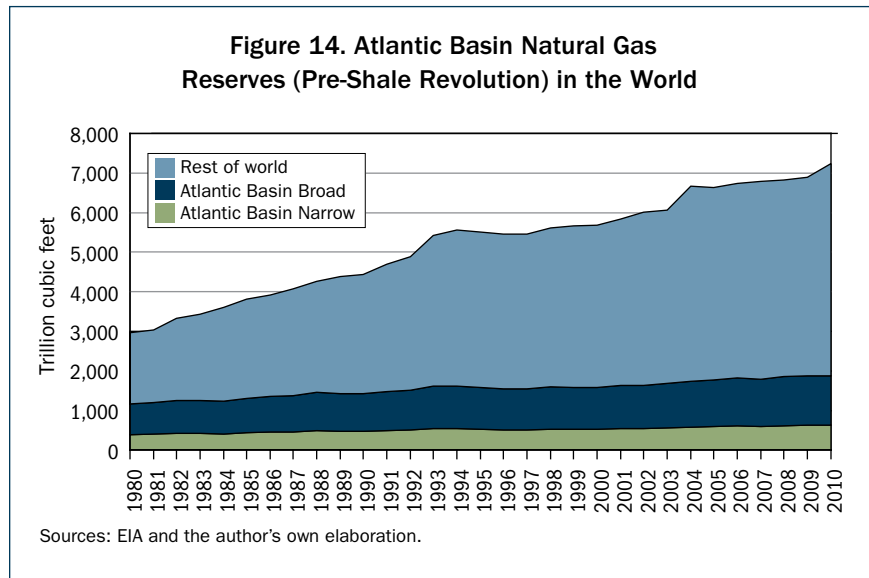
2.3.2 The Natural Gas Map

In some ways, the Atlantic Basin’s gas map is similar to that of its oil. The biggest gas producer (the United States, which according to BP produced 611bcm — or 21.6tcf — in 2010) is also the largest gas consumer (683bcm or 22.5tcf). The next-largest producers are Canada (160bcm or 5.7tcf), Norway (106bcm or 3.7tcf), Algeria, and Egypt in the broad conception of the basin (80bcm or 2.8tcf, and 61bcm or 2.2tcf, respectively), the Netherlands (71bcm 2.5tcf), the U.K. (57bcm or 2.0tcf), Mexico (55bcm or 1.9tcf), Trinidad and Tobago (41bcm or 1.5tcf), Argentina (40bcm or 1.4tcf), and Nigeria (34bcm or 1.2tcf).

In other ways, however, the gas map is different, particularly in the realm of reserves. First, Africa — as opposed to North America — dominates “broad” Atlantic Basin gas reserves (see Figure 13). Furthermore, the “broad” Atlantic holds 1,000 trillion cubic feet of natural gas reserves (see Figure 14), amounting to more than 15 percent of global gas reserves (before accounting for the bulk of the newly estimated unconventional shale and tight gas). Because the “narrow” Atlantic holds 500tcf, we estimate that the Atlantic Basin contains some 12 percent of conventional global gas reserves (750tcf). Should the shale gas revolution prove largely successful around the world (see subsection on shale gas below in the section



on the Upstream), this picture could change. The center of gravity for gas would shift toward the Atlantic Basin, as the basin's share in total global gas reserves would rise to between 20 percent and 30 percent, whereas the gas center of gravity within the Atlantic Basin will shift somewhat to the south.



Nonetheless, should the shale gas revolution be stymied by social, environmental, or economic constraints, it will be difficult for an Atlantic Basin gas system to noticeably increase its global weight. In this sense, even though the Atlantic Basin (with the exception of the United States, at least) has not traditionally been known as a gas power (when compared with the Middle East or Eurasia), a successful shale gas revolution would provide a significant stimulus for the development of an Atlantic Basin energy system and an Atlantic Basin consciousness (see subsection on shale gas below in the section on the Upstream). Therefore, the debate over shale gas now under way should be dealt with scrupulously, carefully weighing the interests and claims of all stakeholders involved, from industry to environmental groups.

2.4 Recent and Future Hydrocarbon Trends in the Atlantic Basin

2.4.1 *The Upstream*

The Atlantic Basin “upstream” is currently the most dynamic among those of the world’s three ocean basins. The frontier of “difficult oil” — including deep offshore and Arctic oil, as well as unconventional oil (e.g., Canadian tar sands, Bakken shale oil, and Orinoco super-heavy oil) — has been developed more intensively in the Atlantic than anywhere else. The so-called shale gas revolution was born in the Atlantic, and will likely move beyond the United States into other areas of the Atlantic Basin (such as Argentina, Poland, and South Africa) faster than into the Indian Ocean or Pacific Basin (China being one potential exception). Shale gas production in the Atlantic Basin has already provoked a global gas glut, with gas prices in the basin diverging not only from the historically high price of oil, but also from the higher price of gas in Asia. Finally, the Atlantic Basin is also home to most of the global petroleum industry’s new hot spots for potential big plays, including Greenland, West Africa, and the Falkland Islands.

The prospect of major oil production within the Arctic Circle — where international oil companies (IOCs), along with the sovereign nations of the region (Canada, the United States, Denmark, Norway, and Russia) are already jockeying for position — represents the first significant potential source of new hydrocarbons for the Atlantic Basin from the northern frontiers of “difficult oil.” The U.S. Geological Survey (USGS) estimates that the Arctic contains 25 percent of the world’s undiscovered hydrocarbons, including 90 billion barrels of recoverable undiscovered oil and 50tcm (1,670tcf) of gas, 80 percent of which is located offshore. According to these estimates, the Arctic would hold 13 percent of the world’s remaining hydrocarbons (discovered and undiscovered) and around 30 percent of the world’s remaining gas. The potential oil boom in the Arctic is also encouraging an increasingly sovereign Greenland (with 31 billion barrels of oil equivalent (boe) off its eastern shore, and another 17 billion boe on

its Canadian side, according to the USGS) to prospect for oil and gas off its Canadian and Atlantic shores.²⁷

But the actual likelihood that major oil production will take place in the Arctic is slight, at least for a decade or two. Although the use of the Arctic Council could produce other, much more immediate benefits (such as stimulating improvements in offshore regulatory regimes and environmental regulatory cooperation in the wake of BP's Macondo spill in the Gulf of Mexico, and providing a governance structure for the Arctic Circle region), hydrocarbons production will continue to be hampered by a number of barriers. The most significant of these include the remoteness of the Arctic fields, the current lack of infrastructure, the rapidly changing and highly sensitive Arctic environment, and extremely dark and cold conditions.²⁸ Of course, the feasibility of investment in Arctic oil and gas is at least partially limited by:

- the high volatility of world oil prices (i.e., the capacity of the oil price to plunge temporarily, as it did in the autumn of 2008, even while it rises over the long run, as it has done over the past decade); and
- the potential delinking of the price of gas from that of oil, a market transformation that appears to be currently under way (see the section on Repercussions of the Shale Gas Revolution).

Given the messy stalemate (post-BP Gulf spill) over the future of offshore regulation in the United States, it is difficult to imagine meaningful quantities of new oil coming out of Alaska's northern waters anytime soon. Some oil companies confirm this, no doubt feeling wounded by their experiences as pioneers on the frontiers of Alaska's Arctic offshore. Having invested \$4 billion in prospecting the Beaufort and Chukchi Seas (only to have government approval for exploration withdrawn after the Macondo spill), Shell has claimed that even if the U.S. government were to allow for more leasing in Alaska's Beaufort and Chukchi fields, "not a single one would be purchased because the U.S. government lacks credibility

²⁷ See Miles Lang, "Jubilee lights the way for exploration hot-spots," *Petroleum Economist*, February 2011.

²⁸ Brendan Kelly, Deputy Director, Division of Arctic Sciences, National Science Foundation, comments on "Arctic Oil and Gas Development," *Impacts of the Gulf Oil Spill Series*, July 12, 2011 (Center for Strategic and International Studies, Washington, DC).

because it has not provided a predictable regulatory atmosphere for exploration and production.”²⁹ Nevertheless, after undertaking a major redesign of its drilling and spill response programs, Shell’s Chukchi Sea operations have received preliminary approval, and the same is expected soon for the company’s Beaufort Sea plans. The company expects to receive final government approval to begin drilling by July 2012.³⁰

The validity of Shell’s claim notwithstanding, the U.S. government remains reluctant to open significant and contested portions of the national coastline for more offshore exploration and production. The United States and international environmental movements are likely to continue their attempts to block the entry of the petroleum industry onto the frontiers of “difficult oil,” given their commitment and dual concern for the potentially disastrous ecological effects of deep offshore drilling, particularly in the far north, and for the climate impact of an economic and technological trajectory that continues to burn oil no matter how difficult or disastrous it is to obtain and use. Although the Obama administration has flirted with a limited opening of the Atlantic coast and parts of the eastern Gulf of Mexico, it is still unlikely that significant drilling will occur over the medium term, even if future U.S. governments appear to abandon all pretenses of attempting to reduce carbon emissions.³¹ Nevertheless, much of the U.S. offshore remains part of the potential “deep reserves” of the Atlantic Basin.

Ironically — as the advocates for offshore drilling in the United States rarely fail to point out — it is very likely that the country’s Atlantic Basin neighbors will continue to expand their offshore oil and gas production. Canada is moving forward to exploit

²⁹ See Pete Slaiby, Vice President, Shell Alaska, comments on “Arctic Oil and Gas Development,” *Impacts of the Gulf Oil Spill Series*, July 12, 2011 (Center for Strategic and International Studies, Washington, DC).

³⁰ Kim Murphy, “Shell rig prepares to drill exploratory wells in Arctic,” *The Washington Post*, March 11, 2012.

³¹ All of the Republican Party candidates in the 2012 U.S. presidential election, however, have vowed to intensify domestic offshore exploratory drilling and to lift prohibitions on most offshore drilling in U.S. economic waters.

Arctic oil in a collaborative fashion.³² Meanwhile, Mexico/Pemex is exploring imaginative ways to maintain the country's constitutional commitment to keep foreign oil companies out of its petroleum sector, while still allowing state-controlled Pemex to penetrate the U.S. Gulf through its increased participation in Repsol (a partnership that could foreshadow future joint ventures with Pemex to exploit untapped deepwater oil in Mexico's Western Gulf).³³ Even Cuba (whose northern oil province contains up to 2 billion bbl of oil) is about to commence further drilling off its northern coast, as is the Bahamas.³⁴ And, of course, Brazil is now plunging into its own deep offshore pre-salt deposits, with many other countries of the southern Atlantic, including Atlantic Africa and Argentina, eager to follow and even collaborate with it (see the subsections below on the West African Transform Margin, the Gulf of Guinea, the Falkland Islands, and Brazil).

Difficult oil is also being further developed onshore. Despite protests from environmentalists, Alberta is expected to intensify the exploitation of its oil sands, at least as soon as the controversial proposed Keystone XL Pipeline has been completed. In late August 2011, the pipeline proposal received a relatively favorable initial environmental impact statement from the U.S. Department of State. An international environmental campaign lobbied the Obama administration very intensely (with a mass protest staged outside the White House) during the fall of 2011, hoping to convince the State Department to finally reject the proposal. When the Obama administration was forced, by a legislative maneuver of its Republican adversaries, to make a precipitous decision on the

³² "Unlike other nations, Canada is thrilled at the chance to begin international cooperation on developing Arctic resources, and to co-lead work on oil spill response in the Arctic with Norway." Mimi Fortier, Director General, Northern Oil and Gas Branch, Department of Indian and Northern Affairs, Canada. Comments on "Arctic Oil and Gas Development," *Impacts of the Gulf Oil Spill Series*, July 12, 2011 (Center for Strategic and International Studies, Washington, DC).

³³ Jorge Pinon (Pinon Energy), Visiting Research Fellow, Latin American and Caribbean Center, Cuban Research Institute, Florida International University, in an email note to Gulf energy watchers, August 30, 2011.

³⁴ Eric Watkins, "Cuba boosts oil, gas production slightly," *Oil and Gas Journal*, August 22, 2011; Neelesh Nerurkar and Mark P. Sullivan, "Cuba's Offshore Oil Development: Background and U.S. Policy Considerations," *Report for Congress*, Congressional Research Service, July 21, 2011; Lesley Clark and Sara Kennedy, "Cuba to drill for oil in water deeper than failed BP well," McClatchy Washington Bureau, Sept. 29, 2010; and David Goodhue, "Bahamian oil firm ready to drill by 2012," *Keys Reporter*, May 27, 2011. In recent developments, however, two exploratory wells have come up dry in Cuba, and Repsol has announced it is ceasing exploratory activities in Cuba.

Keystone project, it decided against it (at least until the project backers can present a credible and more acceptable pipeline route).

Despite the current politicization of the Keystone XL Pipeline, it could still become a reality. Its great appeal to its proponents is that it would not only bring more “safe” Canadian oil to the United States, but it would also reinforce the link from Alberta’s oil sands (and possibly also from the United States’ Bakken shale oil play) first to Cushing, Oklahoma, and then to the U.S. refinery system on the Gulf Coast and, with that, on to the Atlantic Basin instead of the Pacific Basin, as a rival pipeline project from Alberta to the Pacific would propose. Under this future Keystone scenario, Canadian sands oil would join Venezuela’s extra-heavy Orinoco crudes in the Gulf of Mexico and farther afield in the Atlantic Basin — unless Venezuela someday sends a significant amount of its oil to China (although another pipeline through Colombia to the Pacific would probably be required). Venezuela is unlikely to ever really pursue such a goal, to any significant degree, and with any long-run stability, for reasons that are elaborated further below.

Both Canada and Venezuela boast unconventional oil reserves equivalent to the world’s conventional “proven” oil supplies (somewhere between 1.1 and 1.3 trillion barrels). International references (such as the EIA, the IEA, and BP) typically are more modest (although they do not always agree) when categorizing unconventional crude as proven reserves. It seems more reasonable to posit some 250 billion bbl of eventual proven reserves for both the tar sands and the extra-heavy Orinoco oil, giving Canada and Venezuela nearly one-third of global proven reserves and leaving the Atlantic Basin with well over 40 percent.³⁵ Canadian sands oil production now averages more than 1.25mbd (about half of all Canadian production), and Venezuelan extra-heavy oil production has risen steeply in recent years to somewhere between 300,000bd (the IEA’s figure) and 500,000bd (PDVSA’s figure).³⁶ A significant increase (possibly anywhere from 15 percent to 30 percent) in the world’s proven oil reserves (currently some 1.25 trillion barrels, according to BP, excluding both Canada’s oil sands and Venezuela’s super-heavy oil) could feasibly come out of the Atlantic Basin in

³⁵ For more on the reserve figures for Canadian and Venezuelan unconventional oil, see the discussion on oil reserves in the section on The Oil Map of the Atlantic Basin.

³⁶ See Government of Alberta, *Alberta’s Oil Sands: Opportunity, Balance*, March 2008.

the future, possibly taking the basin's relative share of the world's proven oil reserves to 50 percent and beyond.

However, both countries face significant barriers to fully exploiting the potential of their unconventional oil. Perceived political and economic instability continues to limit the capital available for further investment in Venezuela's Orinoco Belt (increasingly supported now by the Chinese). For Canada, the Keystone XL Pipeline is not yet completed, whereas the oil sands' contributions to carbon emissions are set to rise to over 400 MT by 2050.³⁷ Because of the energy-intensive extraction and refining processes required for unconventional oil, such oil tends to emit two to four times the amount of CO₂ emitted by conventional oil. Even if combustion of final oil products is included in the calculation (the "well-to-wheels" approach), unconventional emissions are still 10 percent to 45 percent higher.³⁸ The environmental and political constraints surrounding future significant increases in the production of these unconventional crudes will likely exacerbate political and regulatory uncertainties, holding back the necessary

³⁷ Alberta's emissions are projected to grow to 400 megatons (MtCO₂e) by 2050, largely due to projected growth in the oil sands sector. Alberta's 2008 Climate Change Strategy aims to cut the projected 400 MtCO₂e in half by 2050, with a 139 MtCO₂e reduction coming from carbon capture and storage, and the bulk of these reductions (100 MtCO₂e) coming from activities related to oil sands production. See Government of Alberta, *Alberta's climate change strategy*, January 2008. Furthermore, the EU has recently made a ruling classifying Canadian sands oil as especially pollutant, carrying with it extra administrative and tax burdens for such oil to enter the European market, perhaps mortally threatening a principal *raison d'être* of the Keystone XL Pipeline reaching all the way from Alberta to the refinery system on the U.S. Gulf Coast and on across the Atlantic Basin to Europe. This European position (combined with the very real possibility that the U.S. EPA will ultimately and definitively override State Department approval of the Keystone project) overshadows the pipeline's future. The possibility of Alberta sending most of its sands oil west into the Pacific is still a possibility, and probably far more so than that of Venezuela sending large quantities of Orinoco super-heavy oil to China. Some prominent opponents to the Keystone XL Pipeline, such as climatologist Steve Hansen and environmentalist Bill McKibben, claim that any serious development of the Canadian oil sands would release sufficient CO₂ to push any realistic defense of the 2 degrees Celsius (above pre-industrial levels) limit agreed upon at the Copenhagen Climate Change Summit in December 2009 beyond the world's reach.

³⁸ Joseph J. Romm, *Hell and High Water: The Global Warming Solution*. New York: Harper Perennial, 2008; and Bob Weber, "Alberta's oil sands: well-managed necessity or ecological disaster?" *Moose Jaw Herald Times*. Canadian Press, March 29, 2010. A 2009 study by CERA estimated that production from Canada's oil sands emits "about 5 percent to 15 percent more carbon dioxide, over the 'well-to-wheels' lifetime analysis of the fuel, than average crude oil." See Timothy Gardner, "Canada oil sands emit more CO₂ than average: report," *Reuters*, May 19, 2009. Meanwhile, IEA figures show that carbon dioxide emissions from Canada's tar sands are 20 percent higher than average emissions from oil. With coal's CO₂ emissions about one-third higher than conventional oil emissions, this would make the tar sands' emissions equal to about 90 percent of the CO₂ released from coal. See David Strahan, "Who's afraid of the tar sands?" davidstrahan.com, December 8, 2009.

commitments of investment. Finally, both are particularly sensitive to the volatility of global oil prices, carrying as well this extra cost burden of unconventional crudes over others. Although the cost variable slightly favors Venezuela over Canada, investment in the oil sands still seems a safer bet from the point of view of policy consistency and regulatory certainty, even in the face of the carbon constraint.

A slew of other new oil and gas plays abounds within the Atlantic Basin — far more than in the Indian Ocean or Pacific Basin (where hydrocarbons are relatively scarce, with Persian Gulf crude and Australian gas being the only major exceptions), or on the Eurasian landmass (where geological disappointments and numerous “above the ground” policy and market barriers have significantly eroded the initial promise of Central Asian and Caspian oil and gas, at least for Western — or Atlantic Basin — energy consumers). Beyond the prospect of major oil deposits in the Arctic Ocean and offshore Greenland (and the potential for new reserves to be discovered in the Gulf of Mexico and offshore Cuba), most of the Atlantic Basin’s new oil prospects generated by new deepwater drilling techniques and potential energy policy evolution around the Atlantic Basin appear to be in the deep offshore areas of the southern Atlantic.

The first and fastest Atlantic Basin hot spot is the West African Transform Margin, a series of offshore oil formations running from Guinea through Sierra Leone, Liberia, and the Ivory Coast to Ghana, where a number of discoveries have been made recently. The new pioneer has been Ghana’s Jubilee field, where Tullow Oil and Kosmos Energy took only three and a half years to bring oil on line. Jubilee now produces more than 120,000bd and is expected to reach 240,000bd by 2014.³⁹ Should the boom continue — sufficiently overcoming the expected regulatory underdevelopment and uncertainty inherent in almost all new oil plays in the developing world — Ghana will become a relevant oil producer and exporter, with all the attendant energy, development, macroeconomic, and foreign policy implications. Although Ghana might be better equipped to deal with the challenge of the “resource curse” than its other West African neighbors, in order to

³⁹ See Miles Lang, “Jubilee lights the way for exploration hot-spots,” *Petroleum Economist*, February 2011.

avoid the curse's corrosive dynamics it will need to maintain strict policy vigilance.

Farther west along the Transform Margin, independent Anadarko Petroleum Corporation is preparing Sierra Leone's offshore Venus field for production. Together with partners Repsol and Tullow Oil, Anadarko is measuring the very light crude (80 percent '34-42' API, 20 percent 24 API) of the Mercury-1 block, discovered in the Sierra Leone offshore in November 2010. Chevron is prospecting in offshore Liberia, where it holds a 70 percent interest in (and operatorship of) three offshore blocks, adjacent to another Anadarko block with good prospects. Following the West African coast northward, beyond the Transform Margin, PETRONAS is active at Chinguetti in Mauritania, as is Dana Petroleum at Cormoran-1 and Pelican-1.⁴⁰

Meanwhile, a number of independent oil companies have jockeyed for years for exploration rights in Morocco's offshore, including the waters off the Western Sahara.⁴¹ The Moroccan government should take this interest as an incentive to lay out a well-planned strategic response in advance of any eventual discovery of oil in its own uncontested waters — but especially for an oil discovery in any waters it still might contest with other countries. Although such an eventuality may still be considered a low-probability event, the discovery of significant reserves of high-quality oil in Morocco's offshore could be a high-impact event. Oil could be a looming “black swan” for Morocco, with significant strategic implications, opportunities, and risks.⁴²

Back down in the corner of the Gulf of Guinea — bounded to the north and south by the traditional oil producers of Nigeria and Angola, respectively — a number of potential oil plays could reveal much untapped potential in offshore Equatorial Guinea and São Tomé and Príncipe. The boom began 15 years ago with large

⁴⁰ Ibid.

⁴¹ See Inigo More, “Se multiplica el riesgo petrolero en la frontera Sur,” Analysis del Real Instituto Elcano, Elcano Royal Institute, ARI N° 140/2003, Madrid, January 2003.

⁴² A “black swan” refers to a high impact event that is widely perceived to be highly improbable — coming as a surprise to observers — which after the fact is often inappropriately rationalized with the benefit of hindsight. See Nassim Nicholas Taleb, *The Black Swan: The Impact of the Highly Improbable*, Random House, 2007.

discoveries in the Equatorial Guinea offshore of Bioko Island.⁴³ After a slow start, Equatorial Guinea has recently emerged as a major oil producer in the Gulf of Guinea. Following a liberalization of the hydrocarbons regulatory regime in 1998, the conclusion of a licensing round in 1999, the creation of a state oil company in 2001, and the subsequent exploitation of the country's main Zafiro and Alba fields (by ExxonMobil and CMS Nomeco, respectively), Equatorial Guinea's production rose from virtually nothing in 1996 to 350,000bd in 2004, making it the third-largest oil producer in sub-Saharan Africa.

Equatorial Guinea's boom generated a dramatic increase in government revenue and per capita income for the country, although most of the benefits appear to have been captured by the small ruling elite. Furthermore, oil production peaked in 2004 and maintained a plateau of some 350,000bd for five years. However, production had fallen back to 275,000bd by 2010, leaving Equatorial Guinea behind Congo-Brazzaville in the ranking of sub-Saharan African oil producers. Fears that the country is sliding into the classic petrostate's oil curse have been increasingly confirmed. Comprehensive reform is probably necessary in Equatorial Guinea, but significant change is particularly urgent in the realm of energy policy and regulation, as well as macroeconomic and development management, including more transparency and the adoption of a "best-practices oil regime."⁴⁴

The stakes are even higher, perhaps, in tiny neighboring São Tomé and Príncipe, where a fledgling multiparty democracy exists — and could be lost. Although there is no reliable estimate for São Tomé's reserves, some analysts have speculated there could be 1 billion barrels or more in potential reserves. This would give the country one of the highest per capita reserve rations in the world.⁴⁵ Only a

⁴³ BP estimates Equatorial Guinea's proven reserves at 1.7 billion bbl, compared with Nigeria's 37 billion bbl and Angola's 14 billion bbl, and more in line with Gabon's 3.7 billion bbl and Congo-Brazzaville's 1.9 billion bbl.

⁴⁴ One African oil scholar, John Ghazvinian, claims that Equatorial Guinea is "a family business masquerading as a country. It's one of the most closed societies on earth." See "The Resource Curse: Why Africa's Oil Riches Don't Trickle Down to Africans," *Knowledge@Wharton*, October 31, 2007.

⁴⁵ One billion barrels would give São Tomé and Príncipe a per capita reserve level of 6.1 million barrels per 1,000 of population, the sixth highest in the world, right behind Libya and just ahead of Canada. Meanwhile, Angola is 11th (2 million bbl per 1,000), Gabon 15th (1.3 million); and Equatorial Guinea 16th (1 million).

fraction of such reserves would be enough to transform the life — for better or for worse — of what is one of the world’s smallest and poorest countries.

São Tomé has attempted to follow Equatorial Guinea into the new Gulf of Guinea oil boom. In August 2000 a poorly defined maritime border with Nigeria was settled hurriedly in anticipation of oil exploration, and a Joint Development Zone was established by the two states.⁴⁶ In the meantime, São Tomé and Príncipe has received millions of dollars in assistance from the international development community to prepare for oil sector development. Still, while exploration continues, no oil has yet flowed, leading some analysts to be less enthusiastic about the potential in São Tomé’s offshore.

São Tomé stands to gain significant revenue both from the bidding process and from follow-on production, should reserves eventually match expectations. However, the government remains ill-equipped to manage significant hydrocarbon revenues successfully. If such new oil revenue is managed poorly, the fragile state could fall into a crippling spiral of corruption. The country suffers from acute poverty and a near-complete lack of institutional capacity. Evidence of São Tomé’s initial failure to improve the management of its potential oil resources has already culminated in the country’s effective expulsion from the Extractive Industries Transparency Initiative (EITI) in April 2010, along with Equatorial Guinea.⁴⁷ This is not a sign that augurs well for the future of São Tomé and Príncipe, or its oil.

A new government was formed after the elections in September 2010, and by the end of that year São Tomé had announced the companies selected as the winners of a late 2010 round of bidding for offshore drilling rights in its Exclusive Economic Zone. So

⁴⁶ In 2001, São Tomé and Nigeria reached agreement on joint exploration for petroleum in waters claimed by the two countries. After a lengthy series of negotiations, in April 2003 the Joint Development Zone (JDZ) was opened for bids by international oil firms. The winning bids for the first block (ChevronTexaco, ExxonMobil, and the Norwegian firm Equity Energy) were announced in April 2004, with São Tomé to take in 40 percent of the \$123 million bid revenue, and Nigeria the other 60 percent. See Phuong Tran, “São Tomé and Príncipe Still Waiting for Oil Boom.” VOA News, Voice of America, February 1, 2007 (<http://voanews.com/english/archive/2007-02/2007-02-01-voa30.cfm>)

⁴⁷ This international initiative aims to strengthen governance by improving transparency and accountability through the verification and full publication of company payments and government revenues from oil, gas, and mining. See Human Rights Watch, “An Uncertain Future: Oil Contracts and Stalled Reform in São Tomé e Príncipe,” August 2010.

the country still has an opportunity to change its current course. The new government should seek to review the arrangements for oil exploration in the Joint Development Zone with Nigeria, re-establish contacts with the EITI Secretariat, and introduce international best-practice standards in the contractual and regulatory realms. On the other hand, São Tomé and Príncipe has the advantage of being able to learn from the experiences of Gabon, Nigeria, and, more recently, Equatorial Guinea.⁴⁸

What began in Gabon half a century ago and then spread, first to Nigeria and Angola in the 1970s and 1980s, and then to the tiny nations of the Gulf of Guinea toward the turn of the millennium, now has the potential to coalesce into an “African Atlantic oil rim,” principally in the deep offshore. Indeed, one-third of the world’s new discoveries of oil have taken place in Africa. A continued boom in the West African Transform Margin could consolidate this rim from Angola through the Gulf of Guinea to Nigeria, all along the West African Coast to Senegal. This oil rim might even reach all the way to Morocco.

Despite all the dynamism on the African side of the Atlantic, Brazil has transformed the traditional hydrocarbons supply picture more than any other country in the Atlantic Basin. Brazil’s large subsalt (pre-salt) deposits — discovered over the past five years in the Santos and Campos basins off the country’s southeastern coast — represent the world’s largest oil discovery in many decades and constitutes the biggest current oil play. Official proven reserves have nearly doubled (from 8 billion bbl to 14 billion bbl, according to BP) in less than five years, whereas the government and most other Brazilian estimates place them at 50 billion bbl; still others have them at three or four times that amount. In addition, given that the geographies of Brazil and Africa are linked, ultra-deepwater oil is likely to be increasingly important along the Atlantic littoral of Africa, as the current oil booms in the Gulf of Guinea and the West African Transform Margin attest.⁴⁹ Brazil’s deep offshore subsalt

⁴⁸ Ibid.

⁴⁹ Fueling the sensation that deepening Brazil–Africa connections (both geological and energy-related) might continue to propel the formation of a southern Atlantic Offshore oil ring, Tullow Oil (the independent that has been a pioneer in Africa) announced on September 9, 2011 a major new discovery off the coast of French Guiana (just north of Brazil). The company has called its Zaedyus well the “mirror” of its flagship Jubilee field in Ghana’s offshore. “The discovery at Zaedyus (in French Guiana) has proved the extension of the Jubilee-play across the Atlantic,” said Angus McCoss, Tullow’s exploration director.

technology could be of great interest to the countries of Atlantic Africa. Petrobras already has a long tradition of collaborating in the Nigerian and Angolan offshores, where pre-salt plays are now being developed. The Brazil–Africa oil connection — in addition to a deepening Brazilian-African collaboration in the biofuels sector — could be a crucial vector in the formation of a southern Atlantic offshore oil ring, yet another development that would contribute to the emerging Atlantic Basin energy system.

In 2010, Brazil produced 2.7mbd of liquids, of which 75 percent was crude oil. Brazil’s oil production has risen steadily in recent years, with the country’s oil production in 2010 about 150,000bd (6 percent) higher than in 2009. Most Brazilian oil is produced in the southeastern region of the country in the Rio de Janeiro and Espírito Santo states — in the Espírito Santo, Campos, and Santos basins (running down the Atlantic coast from northeast to southwest), although other oil production also occurs in the Potiguar, Sergipe-Alagoas, and Jacuipe basins in the northeast, and in the Cumuruxatiba and Mucuri basins of the central Atlantic coast. More than 90 percent of Brazil’s oil production is offshore in very deep waters and consists of mostly heavy grades (although many of the new pre-salt discoveries include oil of much lighter grades). Five fields in the Campos Basin (Marlim, Marlim Sul, Marlim Leste, Roncador, and Barracuda) account for more than half of Brazil’s crude oil production. These Petrobras-operated fields each produce between 100,000bd and 400,000bd. International oil companies also play a role in Brazilian production. Shell’s Parque de Conchas project and the Chevron-operated Frade project are expected to achieve production levels of 100,000 bbl/d and 68,000 bbl/d, respectively.⁵⁰ Other IOCs, such as Repsol, and NOCs, such as Sinopec, along with others, have also entered the

⁵⁰ Energy Information Administration (EIA), “Country Analysis Briefs: Brazil,” U.S. Department of Energy, January 2011.

Brazilian upstream recently, even in the pre-salt realm, and despite the country's new special pre-salt regulatory regime.⁵¹

Brazil's partially state-owned oil company, Petrobras, plans to increase its domestic oil production significantly over the coming decade, with current crude oil production levels of 2.2mbd targeted in the company's latest strategic plan to nearly double to 4mbd by 2020.⁵² If such a target were met, Brazil would likely move from its current position as the fourteenth-largest oil producer to the world's fourth-largest. This ambitious target would require large increases in investment spending. Petrobras's latest 2010–2014 five-year plan (released in 2010) plans for capital expenditures of \$224 billion.⁵³ Because Brazilian oil has traditionally been of a relatively heavy grade, the country has typically exported upwards of 20 percent of its crude oil while importing lighter crude from abroad to be refined by Brazil's simpler, more conventional refinery complexes (which are more appropriate for refining lighter grades of petroleum). However, Brazil became a net crude exporter in 2009. Still, the future potential of export levels is unclear, since much will depend on internal energy demand independent of future levels of crude oil and ethanol production.

The Tupi field (discovered in 2007 by a joint venture of Petrobras, BG Group, and Petrogas, and later renamed "Lula," provoking President Lula da Silva himself to claim that "God must be Brazilian") could have 6.5 billion recoverable barrels of oil equivalent (boe), according to EIA estimates. The combined

⁵¹ ExxonMobil and Hess have come up empty in their partnership with Petrobras at their offshore Sabia-1 well in Brazil's deepwater Santos Basin. This is the third well in the block that has come up with only noncommercial quantities of oil. The lack of success in finding oil in the pre-salt area at Sabia has generated some skepticism that discovering pre-salt oil might imply more risk than initially believed. However, Petrobras' recent successes at the Tupi and Iracema fields, as well as in the Santos Basin, have successfully compensated for such potentially negative investment sentiment. On the other hand, companies operating in the nearby Campos Basin have been more successful. The latest find by Brazil's Participações suggests a potential production of 40,000bd of light crude oil. See Business Latin America, Economist Intelligence Unit, February 14, 2011.

⁵² See Helen Robertson, "Brazil banks on pre-salt bonanza," *Petroleum Economist*, April 2011, p. 17.

⁵³ Petrobras' new 2011–2015 five-year plan has been delayed.

resources of the Tupi/Lula and Iracema (renamed Cernambi) fields reach 8.3 billion boe, according to Petrobras.⁵⁴

Brazil's pre-salt fields have become the most significant hydrocarbons discovery of the last decade. As crude production rises from 2.2mbd to 3mbd by 2014, the pre-salt fields are projected to supply less than 10 percent (or 241,000bd) of the total by that year. However, by 2020, pre-salt fields are expected to supply 25 percent (or 1.08mbd) of Brazil's total 4mbd of output that Petrobras projects for that year.⁵⁵ In theory, this low ratio of projected pre-salt-to-total Brazilian production in 2020 represents a certain margin for Brazilian oil strategy. On the one hand, it suggests huge potential for further increases in Brazilian oil production beyond 2020, possibly to as high as 6mbd or 7mbd. On the other hand, some Brazil watchers already warn of the enormous costs of the infrastructure trail necessary to support what will be an unprecedented technological feat — “entire floating cities” in the basins off Brazil's southeastern coast. If the costs of the effort prove too large, ultimate pre-salt production levels could be constrained. It might be prudent to project future Brazilian oil production with this in mind.

Estimates of Brazil's pre-salt hydrocarbons resources vary. According to *Oil and Gas Journal*, Brazil has proven oil reserves of around 13 billion boe. Currently, BP estimates that Brazil has some 14.2 billion boe. On the other hand, the ANP (Brazil's National Petroleum Agency, which acts as the sector regulator) estimates that Brazil's total recoverable oil and gas reserves come to around 50 billion boe. Some recent Brazilian estimates put the pre-salt's total recoverable oil reserves at more than 100 billion boe, and some even as high as 200 billion boe.⁵⁶

⁵⁴ The Tupi field contains large reserves in a pre-salt zone some 18,000 feet below the ocean surface, under a thick layer of salt. Following the Tupi discovery, numerous other pre-salt finds were made in the Santos Basin, such as Iracema, Carioca, Iara, Libra, Franco, and Guara. Further pre-salt discoveries also occurred in the Campos and Espírito Santo basins. In December 2010, Petrobras submitted a declaration of commerciality to the ANP for the Tupi and Iracema fields (and renaming them the Lula and Cernambi fields, respectively). The total recoverable reserve estimate for these fields is 8.3 billion boe (6.5 billion boe for Tupi and 1.8 billion boe for Iracema). See EIA, op. cit.

⁵⁵ Helen Robertson, op. cit.

⁵⁶ Peter Millard, “Brazil Oil Fields May Hold More than Twice Estimates,” Bloomberg.com, January 19, 2011.

Brazil's pre-salt reserves lie some 18,000 feet below the ocean's surface, beneath a thick layer of salt in the Santos, Campos, and Espírito Santo basins off the shore of the southern coastal states, where the lion's share of the country's offshore oil is located. These significant depths and the high pressures of the oil involved in pre-salt production will require increasing amounts of investment in state-of-the-art technology and a technically sophisticated and specialized workforce. The current consensus of informed opinion, however, judges Brazil's present oil services sector and its stock of qualified engineers to be inadequate to the task of meeting Petrobras' ambitious 2020 targets. This scenario could easily imply technical bottlenecks, particularly in the short and middle run, unless Petrobras, other private sector actors, and the Brazilian state invest heavily in new skills. Such bottlenecks will be exacerbated by Brazil's local content rules for exploitation of the pre-salt reserves, which require 60 percent of all related goods and services to be produced and purchased in Brazil, while 1 percent of turnover must be reinvested in Brazil-based R & D. Furthermore, the intense expansion anticipated by Petrobras will strain the company's E & P resources in general, along with the country's infrastructure, even with the structural advantage of concessional finance from the Brazilian Development Bank (the BNDES).

On the other hand, the promise of the pre-salt boom, and its potential to transform the country's economic position, may serve as a catalyst for expanding public investment in human and physical infrastructure. Such infrastructure investment has seriously lagged behind in national priorities over the last two decades, a period during which Brazil has concentrated on achieving a high degree of (relatively orthodox) consistency in its macroeconomic policy. It has worked to eliminate the inflationary expectations embedded in the economy as a result of the hyperinflationary bouts of the 1980s, and to generate investor-grade credibility in the international markets.

Jose Sergio Gabrielli, until recently the CEO of Petrobras, believes that the company possesses the financial and technological conditions necessary to achieve its 2020 targets.⁵⁷ However,

⁵⁷ At the end of January, Maria das Graças Foster, a business leader and Petrobras executive with close ties to the president of Brazil, Dilma Rousseff, was appointed CEO of Petrobras, replacing Gabrielli.

many non-Brazilian oil sector analysts, particularly those from the traditionally advanced economies — typically opposed to state intervention of any kind in the oil sector, even in the form of regulation — tend to doubt the financial, if not also the technological, capacity of the company to deliver on its targets. Petrobras plans to spend some \$120 billion (more than 50 percent of the \$224 billion budget included in the latest five-year plan) on E & P.⁵⁸ To support such levels of upstream investment, Petrobras plans to issue \$30 billion to \$40 billion in new debt over the next three or four years, although this might put the company up against prudent debt-to-equity limits.

Northern Atlantic analysts tend to believe that Petrobras will need to bring in more joint venture partners in the coming years — and perhaps on somewhat better terms than those recently established in the pre-salt petroleum legislation (addressed more fully below) — in order to share the risk sufficiently to make the ambitious expansion financially and technically feasible. Although Brazil will likely prove more successful in expanding its hydrocarbons services sectors than many northern Atlantic observers now believe or are willing to acknowledge, the country also is likely adjust its energy policies pragmatically in coming years, if necessary, to allow for either less domestic content in the pre-salt or renewables sectors, or more international participation in the pre-salt economy on terms somewhat better than the current ones. The credibility of this forecast is underpinned by Brazil's successful and pragmatic history in both macroeconomic and energy policy, as suggested above.⁵⁹

In any event, in September 2010, Petrobras pulled off the largest share flotation in history, designed to jump-start its investment plan to develop the pre-salt fields and preserve its investment-grade credit rating. The flotation raised 120.4 billion reais (\$70 billion at the time) from the Brazilian government and other global investors who purchased 2.4 billion common shares for 29.65 reais each and

⁵⁸ Helen Robertson, *Petroleum Economist*, op. cit.

⁵⁹ Brazilian companies already are responding to the challenge. Earlier this year, Petrobras announced that Brazilian shipbuilder Estaleiro Atlântico Sul (based in Pernambuco state) had won a \$4.64 billion contract to build seven deepwater drilling platforms (\$662.4 million per rig). Due to begin operations in 2015, the platforms are to be built in Brazil and must meet a minimum domestic content requirement of 20 percent. The Estaleiro Atlântico Sul contract is part of Petrobras' plans to acquire 28 offshore drilling rigs to develop deepwater reserves (see Business Latin America, Economist Intelligence Unit, February 21, 2011).

another 1.87 billion shares of preferred stock at 26.30 reais apiece. As part of the share sale, Petrobras issued some \$42.5 billion worth of stock to the Brazilian government in exchange for rights to develop 5 billion bbl of pre-salt oil reserves.⁶⁰

Brazil's new petroleum legislation, designed and approved in the wake of the massive pre-salt discoveries, has also piqued the skepticism of many global oil analysts. The first two pieces of legislation in the new pre-salt regime (passed by the legislature in August 2009 and signed into law in July 2010) created a new state agency, Petrosal, to manage all new pre-salt production, and allowed for the government to capitalize Petrobras by giving the company 5 billion bbl of unlicensed pre-salt oil reserves in return for increasing the government's share in the company (from 40 percent to 48 percent).⁶¹ Two more laws were passed in December 2010, one creating a new national development fund to manage government revenues from pre-salt oil production, and another mandating that Petrobras now become the sole operator — with a minimum 30 percent stake — in all new production-sharing contracts in the pre-salt oil fields not previously under concession, with a minimum 30 percent stake in each contract.

Meanwhile, in September 2010, Brazil's government released a long-anticipated plan for sharing oil royalties among the states. This contentious issue has held up government efforts to develop the pre-salt reserves rapidly, and may even account for the delay in Petrobras' 2011–2015 investment plan. A handful of oil-producing states in Brazil (with Rio de Janeiro the most central among them) are vying with a much larger number of non-producing states, all claiming to deserve a much higher share of the oil revenues than under the current distribution scheme. The government's latest proposal would cut the amount of royalty revenue received by the

⁶⁰ Still, doubts around Petrobras have persisted, particularly as the share price has fallen from more than 30 reais around the time of the share flotation (after having peaked at 60 reais just before the financial crash in September 2008) to around 23 today. Fears of increasing political interference in Petrobras and related oil policy, market concerns surrounding the company's debt levels, and technical worries stemming from the delay in the release of the 2011–2015 five-year investment plan all tended to push down Petrobras's share price during most of 2011.

⁶¹ Today, however, Brazilian government directly owns 54 percent of Petrobras' common shares with voting rights, while the Brazilian Development Bank (BDNES) and Brazil's Sovereign Wealth Fund (Fundo Soberano) each control 5 percent, bringing the state's direct and indirect ownership to 64 percent. See "Governance - Capital Ownership," Petrobras Investor Relation Site, April 9, 2011 (<http://www.petrobras.com.br/ri>).

federal government to 20 percent of the total by 2020 (down from 30 percent under current legislation), whereas revenue for the nonproducer states would jump more than tenfold to 23 percent in the same period.⁶² Once this issue has been resolved by new legislation, President Dilma Rousseff hopes to hold new auctions for deepwater fields by the second half of 2012, the first such offer since 2007. Still, unless a solution to the royalties distribution controversy is found immediately, this inaugural pre-salt licensing round is likely to be pushed back to 2013.

Some analysts fear that the new regime's increased level of state involvement — and its heightened drain on Petrobras resources — could slow the development of the pre-salt fields. Indeed, there are voices on the left-wing of President Rousseff's ruling PT (Workers' Party) that still call for even more state control over the oil sector. However, for reasons analyzed earlier, it is unlikely that Brazil's oil regime will be tightened further. On the contrary, it is possible that the current government will ultimately relax certain aspects of the pre-salt regime, at least to a certain degree. In any case, Brazil has long exhibited a pragmatic evenhandedness in the evolution of its energy policy, quite similar to that evident in the evolution of its macroeconomic policy management over the past two decades. When the sector was partially privatized and liberalized in the late 1990s, the reforms were clear and attractive, but far more restrained than the liberalizing *apertura* of Venezuela during the same decade. Likewise, in the wake of the pre-salt discoveries, Brazil's increased state control over its oil sector — to be expected given the startling change in Brazil's oil horizon — was much more moderate and business-friendly than the recent statist policy shifts of many other Latin American oil producers such as Venezuela, Bolivia, and Ecuador, where the state seized the lion's share of the sector's rents in response to rapid upward movements in prices (as opposed to a major new discovery by the state-owned company, due primarily to its own investment in accumulated technological prowess, as was the case for Petrobras in Brazil).

⁶² The debate over pre-salt royalty distribution among Brazilian states is expected to continue into 2012. At the time the government announced its new proposal for oil revenue sharing, Henrique Eduardo Alves, a leader of the government-allied PMDB party in the Chamber of Deputies, claimed that the proposal would not meet the demands of non-producer states, despite the significant increases proposed for their revenue shares. See the Latin America Energy Advisor, "Brazilian Government Proposes New Oil Sharing Plan to States," Inter-American Dialogue, Washington, DC, September 11–16, 2011.

Furthermore, Petrobras makes the argument that pre-salt production expansion will push the rest of the sector forward, stimulating development all across and along the high-tech production chain. It is also likely that the sheer volume of pre-salt reserves will compel Brazilian and international companies alike to acquire stakes (even if only minority shares) in the pre-salt play. Chinese companies have been lining up for investment. Sinopec, for example, bought a 40 percent stake in Repsol's Santos Basin pre-salt assets for \$7.1 billion in October 2010. Repsol itself has planned CAPEX investment of up to \$5 billion for its Brazilian operations from 2010–14 and another \$6 billion to \$9 billion for 2015–19, but it has needed outside cash to fully develop its pre-salt assets in the Santos Basin (which, according to the EIA, could hold up to 50 billion boe). Another Chinese company, Sinochem, spent just over \$3 billion earlier in 2010 to buy a 40 percent interest in Statoil's offshore Peregrino field, where the first oil was scheduled to flow sometime during 2011. In March 2011, the BG Group announced it would invest as much as \$30 billion in Brazil during this decade, including the creation of a technology center to help address the current oil services gap for developing the pre-salt reserves.

It remains to be seen whether international companies (either IOCs or NOCs) participate as fully as Petrobras would like during the next pre-salt bidding round, the first under the new conditions. In the end, however, if the draw of the largest oil play in recent years — in a country that is now one of the most stable, open, and dynamic emerging markets in the world — is not quite enough to attract sufficient capital and skills to realize its potential, it is likely that the pragmatism for which Brazil has come to be known will provide for sufficient financial and technological cooperation opportunities with domestic and international oil companies in order to maximize the potential of its pre-salt oil.

Brazil's President Dilma Rousseff has not shared all of former President Lula's eagerness to engage in certain relationships abroad. She announced a new focus on human rights while backing off on involvement with Iran or exploration for oil in Cuba, both of which were energy-based endeavors in dictator-led countries. Nevertheless, as former Minister of Mines and Energy, and as Chairman of Petrobras, Rousseff knows the energy sector well. She also has claimed that Africa will remain a political and economic

priority for Brazil in the future. Africa is important to Brazil politically because of its commitment to South–South relationships, whereas economically the continent has long been an important market for Brazilian exports. Brazil’s interests in Africa, however, revolve primarily around energy production — in particular, oil and biofuels.⁶³

As a legacy of the southern Atlantic slave trade, Brazil has deep historical and cultural ties with Africa. Its black population is the world’s largest outside of Africa and second only to Nigeria in the world. But Brazil’s economic and diplomatic relations with African countries really did not begin in earnest until the mid-1970s, when Brazil began to support newly independent African countries as they emerged from colonization. Many African countries (especially Portugal’s former colonies of Guinea-Bissau, Angola, and Mozambique) became export markets for a newly industrializing Brazil. As the trade relationship developed, it deepened into services and technology transfer. Brazil’s budding economic partnership with Africa also first provided it with a claim to represent other developing countries on the global diplomatic stage. Trade with Africa has remained an important government priority since the 1970s, even if the economic crises of the late 1980s and early 1990s rendered both Brazil and Africa incapable of deepening their economic and political relations still further, at least for some time.

More recently, Africa has become one of Brazil’s logical partners in the context of its new South-South policy, driven by what longtime diplomat and government official Celso Amorim has called Brazil’s “desire to exercise solidarity with poor nations.”⁶⁴ President Lula strengthened Brazil’s relationship with Africa tremendously, making the continent one of his international priorities. Between 2003 and 2010, Lula visited Africa 12 times, traveling to 23 countries in total. Brazil now has embassies in 33 countries on the continent. Trade with Africa grew five-fold between 2002 and 2008 (from \$5 billion to \$26 billion).⁶⁵ This enhanced Brazil-Africa

⁶³ The author owes many thanks to Chris Cote, a former colleague at the Inter-American Dialogue, for his assistance with this section.

⁶⁴ Celso Amorim, “Brazilian Foreign Policy under President Lula (2003–2010): An Overview.” *Revista Brasileira da Política Internacional*, 2010.

⁶⁵ *Ibid.*, p. 234.

relationship has included HIV programs in Mozambique and cotton-growing programs in many countries. But energy, especially oil and biofuels, is one of the principal drivers.

Brazil and West Africa share many geological features since the two regions were connected during earlier geological eras. Seismic studies show that it is a “certainty, not a probability” that there is quality oil in mirror formations in West Africa, as noted by at least one Brazilian geologist. West African offshore oil is often found in ultra-deep waters. Petrobras is one of the few oil companies with the necessary technical expertise to undertake such projects.

Brazil has indeed recognized the opportunity. Petrobras now owns blocks in six African countries (Angola, Benin, Libya, Namibia, Nigeria, and Tanzania), although to date it produces only in Angola and Nigeria, the African countries that receive the company’s largest investments (\$900 million and \$2 billion, respectively).⁶⁶ In 2008 President Lula said that he was “not satisfied with Petrobras’ participation” in Africa and that “what they don’t do, others will.”

For the moment, it is safe to say that Petrobras has its hands full at home. The immense discoveries in the pre-salt offshore have sent Petrobras scrambling to overcome numerous existing barriers to significant expansion of domestic oil production. Such bottlenecks include:

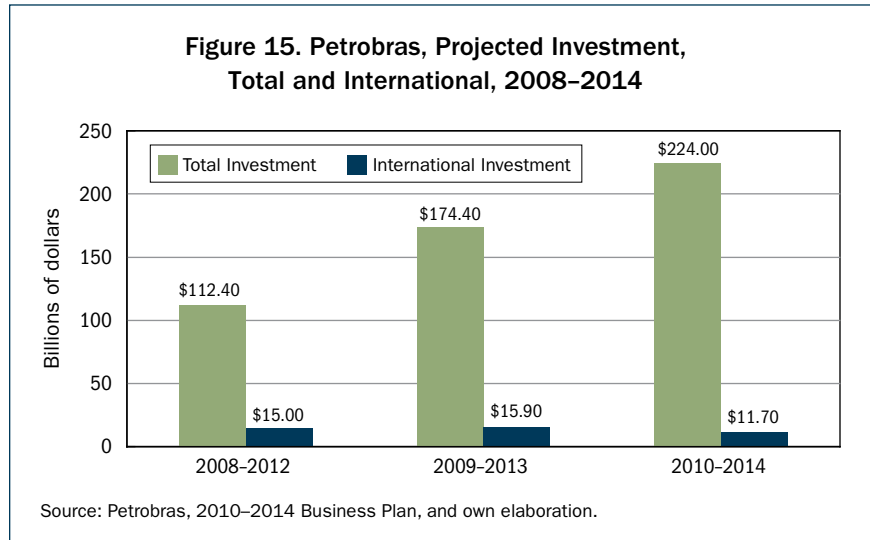
- a relatively high debt-to-equity ratio (making further debt-financing more difficult or expensive);
- a still insufficient supply of adequately trained technical workers; and
- a shortage of both equipment (the company will have to manufacture some custom-made machinery in order to drill in the pre-salt regions) and refinery capacity.

As mentioned above, the challenges facing Petrobras in tackling the pre-salt are formidable.

The company’s previous 2010–2014 Business Plan, a report released annually and targeted at foreign investors, revealed that Petrobras

⁶⁶ Petrobras, Business Plan 2009–2013. Petrobras also owns blocks in Benin, Libya, Namibia, and Tanzania, but in most cases these operations have not moved beyond initial geophysical and geographical studies.

will adjust its strategy to focus more of its resources at home in the short-term future. When the 2010–2014 Business Plan is compared with that of 2008–2012, it can be seen that Petrobras’ projected international expenditures dropped from \$15 billion to \$11.7 billion, whereas projected total overall expenditures doubled, from \$112 billion to \$224 billion (see Figure 15).



Although international spending has fallen significantly (from 13 percent to 5 percent) as a share of total investment, Petrobras has now designated 90 percent of this international investment for exploration and production (E & P), explicitly identifying Africa’s Atlantic coast as the primary target for such international investments, with Angola and Nigeria serving as the central focuses of Petrobras’ petroleum activity in Africa.⁶⁷

Angola, a member of OPEC, is Africa’s third-largest oil producer after Nigeria and Libya. Angola’s government depends on oil revenue for as much as 80 percent of its budget, and the petroleum sector accounts for 40 percent of GDP. Although oil production had reached 1.9mbd by 2008, Angola’s governance record remains shaky and its oil sector lacks transparency. Nevertheless, Petrobras has been attracted to Angola by both the common Portuguese language and the interesting pre-salt potential to be found

⁶⁷ Petrobras is nevertheless involved in a number of other countries within the Atlantic Basin, including Namibia, Benin, Portugal, Mexico, Venezuela, and Uruguay.

there, despite the possible risks typically associated with African oil producers.

As a country, Angola is Petrobras' fourth-largest international investment destination (with a projected \$900 million in investment during 2009–2013). Since 1979, when Petrobras began its operations in Angola, the company has accumulated shares in six blocks and is now the operator in three. During the last few years, Petrobras has made a number of discoveries among its Angolan blocks (it remains a small shareholder in many of them).

As of 2008, Nigeria had the tenth-largest proven oil reserves in the world (36 billion bbl) and the second-largest in Africa (second only to Libya). Nigeria is also the largest oil producer on the continent, and the 15th largest oil producer in the world (2.7mbd). In addition to the abundance of Nigeria's proven reserves, their high quality and relative proximity to Brazil makes Nigeria an attractive option for Petrobras.

Petrobras began operations in Nigeria in 1998 and now has holdings in three blocks (one as operator). Production began in the Agbani oil field in 2008 and in the Akipo field in 2009. Although Petrobras is not operator in either of these fields, such developments have turned Nigeria into "one of Petrobras' international production highlights."⁶⁸ The company's 2009–2013 Business Plan projected \$2 billion of investments in Nigeria. The company will soon begin production in its operator block, OPL 315, and will also enter into a large investment in the Egina field in block OML 135. Development and production, with facilities to produce 200,000 b/d, are scheduled to be ready by 2015.

Even more so than Angola, Nigeria suffers from political instability, violence, and inequality, and it still struggles to implement IMF-guided market reforms. Oil revenue constitutes 80 percent of the national budget. The Nigerian National Petroleum Corporation holds at least 60 percent in all joint ventures. Vandalism and sabotage are the biggest threats to the Nigerian oil sector, particularly in the Niger River Delta, where most of Nigeria's oil is located. Together with unstable government policy, poor corporate governance, and armed robbery and kidnapping, these represent

⁶⁸ Interview with Jorge Luiz Zelada, Petrobras International Director, *Offshore Magazine*, July 1, 2010.

daunting barriers for foreign investors. Still, the Chinese NOCs have shown great interest.

Petrobras is the world's leader in biofuels production; the company projects a doubling of its output over the next four years. In Africa, Petrobras' primary role is as a technical advisor, although more Brazilian firms could soon be producing in the African savanna, which shares a number of physical similarities to Brazil's fecund Cerrado. The Brazilian government now cooperates with, and supports, biofuels development in a number of African countries, including Senegal, Nigeria, Angola, and South Africa within the southern Atlantic, as well as Kenya, Mozambique, and Tanzania beyond the Atlantic Basin.

Petrobras claims that its primary export market for biofuels is Japan, the country with which the company partnered during Brazil's green revolution in the 1970s. The company has recently begun to work again with Japan (a key financial supporter) to expand its work in Africa (particularly in Angola, Mozambique, and Tanzania).⁶⁹ Petrobras is also looking to the European Union, which has set a minimum target of 10 percent consumption of renewable energies in its transportation sector before 2020. The EU maintains high tariffs on the importation of biofuels, a barrier that continues to make market access difficult for Brazil. Many African countries, however, have preferential trading agreements with the EU, agreed upon during decolonization negotiations. As such, Brazilian businesses may gain access to the EU market through investment and production in — and exportation from — Africa.

Paving the way for, or complementing, this investment push has been a form of technical assistance. With respect to Brazil's agricultural involvement in Africa, former President Lula has claimed that the country's intention is to help Africa produce food crops more efficiently and, eventually, to reduce hunger. Africa has long experienced an unusual decline in crop yields, and Brazilian technology and knowledge could help boost production.⁷⁰ Improvements in agriculture will also help prepare the way for greater biofuels production, especially of sugarcane-

⁶⁹ "João Montenegro, "Biocombustíveis na África," *Energiahoje*, April 5, 2011.

⁷⁰ Paulo Roberto Galerani and Claudio Bragantini, "Transfer of tropical agricultural technologies from Brazil to African Countries," *African Crop Science Conference Proceedings* Vol. 8, pp. 1391–98. 2007.

based ethanol. Although biofuels often compete for land and water with food crops, Africa's countries may have enough space and water to accommodate a significant increase in both bioenergy and food production. This type of collaborative involvement in the overlapping realms of bioenergy and agriculture (particularly if it could also extend to land-use management) is a concrete example of Brazil's commitment to South–South cooperation that might provide a stimulus for the development of an Atlantic Basin consciousness.

Furthermore, Brazil promotes biofuels production in Africa through the work of the Brazilian Agricultural Research Corporation (Embrapa), an organization that employs more than 2,300 researchers and is credited with having provided the technical basis for Brazil's green revolution and agribusiness boom. In 2008, Embrapa opened an office in Accra, Ghana, to “promote social development and economic growth through technology transfer and knowledge sharing in the field of agricultural research.”⁷¹ According to institutional reports, Brazil and many African countries share similar soil qualities related to their tropical climate, allowing techniques and technology to be readily transferred across the southern Atlantic. With a \$5 million research project portfolio in Africa, Embrapa has recently partnered with the Forum for Agricultural Research in Africa (FARA) and several other organizations to create the Africa-Brazil Agricultural Innovation Marketplace. The partnership is a forum for the two research institutions, as well as a funder of small projects (issuing up to \$500,000 over the course of two years to support five to seven new research projects).

In addition to its direct bilateral involvement with Africa, Brazil also is working as a technical advisor in various partnerships between the EU (or individual European countries) and African countries. For example, in 2010 Brazil signed an agreement with Mozambique and the European Commission to start a technical working group to assess the feasibility of biofuels production (using either sugarcane or jatropha) in Mozambique. In 2006, Brazil signed on to an agreement with the United Kingdom and African countries to grow sugarcane to be used for both sugar and biofuels,

⁷¹ Embrapa website.

with a particular focus on the Southern African Development Community (SADC). Brazil will serve as a technical advisor on the project, which aims to reduce carbon emissions by producing ethanol as a local substitute for (often imported) petroleum-based transportation fuels and, possibly, also for export. Although such projects remain in the technical preparation stages, they represent significant potential for Brazil to deepen its ties across the southern Atlantic.

Brazil is very involved, bilaterally and multilaterally, in assessing and extracting Africa's energy resources. However, the majority of the action remains at the exploratory or preparatory phase. If Brazil can keep its economy on course and its investments in Africa at least stable, then Brazilian-African energy production should increase over the coming decade. Future Petrobras investments remain somewhat uncertain, as upstream investments abroad are now declining, at least for the foreseeable future. Nevertheless, its overall biofuels investments continue to rise.

Brazil's central role in African agriculture and bioenergy remains limited to a technical advisory capacity, but as studies progress, more Brazilian companies could move in to take advantage of this preparation to gain access to the EU markets through many African countries' preferential trade agreements. If African governments can retain revenue from the resource extraction, manage that money effectively, and care for the environment and local populations, then Brazil's involvement in the continent's energy scene will be clearly positive. Such a development would be highly significant for the development of the Atlantic Basin energy and food security systems, and could help stimulate the initial formation of an Atlantic Basin consciousness.

Rounding out a potential southern Atlantic offshore oil ring is the Argentine offshore and its contested Falklands/Malvinas basins. Until recently, Argentina's offshore was neglected, even as its onshore oil industry fell into long-term decline. Oil reserves and production have been falling since output peaked at 890,000bd in 1998. Some pessimists argue that the decline is irreversible, as the prolific but mature Neuquén and Golfo San Jorge onshore basins will inevitably dry up. Meanwhile, other pessimists believe that the government will never pursue the type of economic and energy

policies necessary to generate enough investment to develop what could actually be rather large resource reserves (even in basins, like Neuquén, thought to be mature; see the subsection below on The Shale Gas Revolution and the Atlantic Basin). As recently as 2006, Argentina experienced a net energy surplus valued at more than \$5.5 billion, but by the end of the decade, this net surplus had been transformed into a deficit of \$3 billion.⁷²

Nevertheless, both industry players and Argentina's officials believe the country's untapped *offshore* potential could revive the declining oil sector. Although the relatively new Argentine state oil company, Enarsa, has been slow to determine the licensing arrangements and partners for some 62 offshore blocks, by 2007 it had joined forces on three blocks (with water depths of up to 10,000 feet) with the Spanish major, Repsol; with Sipetrol (the international division of Chile's state oil company, Enap); and with Petrobras.⁷³

In 2010, Argentina relaunched its offshore program — the “Malvinas basin oil quest” — in response to reports that oil exploration around the British-ruled Falkland Islands was poised to produce at least modest results. This new Argentine exploration push has begun to prospect for oil in the Malvinas Basin, halfway between the mainland coast and the Falkland/Malvinas Islands. So far the search has been inconclusive. The first well, drilled by Repsol-YPF, Petrobras, and Pan American (part Chinese) came up dry in August 2011. Although recently Enarsa has had to postpone the launching of a new bidding round, Brazilian and Chinese interests continue to express interest in further exploration. Furthermore, the Argentine government (and likely any future government, of any political stripe) will continue to emphasize Argentina's sovereignty over these waters and to reassert its claim of sovereignty over the Falklands/Malvinas (the scene of the 74-day Falklands/Malvinas War in 1982, which Argentina lost to Britain at the cost of about 1,000 lives).

The Falklands oil boom was sparked by a flurry of exploratory activity in the North and South Falklands basins, undertaken by a handful of small independent oil companies that, in their search for

⁷² “Argentine offshore oil quest inconclusive,” UPI.com, July 6, 2011.

⁷³ Randy Woods, “Argentina's Offshore Oil Hopes,” *Energy Tribune*, Dec. 18, 2007 (energytribune.com)

high returns, have been willing to take on the higher costs and risks inherent in the exploration of uncharted, remote, ultra-deep waters. Such companies — such as Rockhopper Exploration, Desire, and Borders & Southern — have had to prospect the island’s remote basin with no infrastructure initially in place.⁷⁴ They also have had to endure the political uncertainty generated by Argentina’s continuing claim to sovereignty over the (“Malvinas”) islands. To make matters even more difficult, Argentina has also banned these companies, and any others that supply them, from its territorial waters.⁷⁵ The geopolitical risk now associated with exploratory drilling in the Falkland Islands — given that Argentina has taken its Malvinas claim to the United Nations — might be high enough to keep the large IOCs — that are more interested in Brazilian pre-salt or Argentine shale gas away from the Falkland Islands oil sector. The already burdensome development costs will become even steeper for the small pioneering independents in the Falklands as the geopolitical risk premium drives up financing and development costs, and as the possibility for cost-saving synergies with the Brazilian offshore equipment and services sectors is blocked by Argentina’s loose economic blockade of the Falkland Islands oil sector, at least for the short term (or until the Falklands/Malvinas sovereignty issue is resolved one way or the other).

Nevertheless, the U.K. independent oil company Rockhopper has forged ahead. It first struck oil in 2010 at its Sea Lion field (in consortium with Desire, Falkland Oil and Gas Ltd. (the state company), and Borders & Southern). Although at least two other wells have come up dry since Rockhopper’s find (both Desire’s Jacinta well in the north basin, and BHP Billiton’s Toroa prospect, in a joint venture with Falkland Oil and Gas), the announcement that the Rockhopper discovery could be larger than initially expected has kept optimism alive. After having revised its reserves estimates downward from 230 million to 170 million barrels at

⁷⁴ It cost some £250 million to transport the Ocean Guardian oil rig from Scotland to the Falklands. Since drilling began in 1998, the rig has been contracted by the exploring companies on a rotating per-well basis. See Miles Lang, *op. cit.*

⁷⁵ Argentine President Cristina Fernandez de Kirchner is also pursuing a blockade and blacklisting of all ships suspected of dealing with the Falklands, and ceased all collaboration with the U.K. in areas of mutual interest. Argentina has accused Britain of refusing to abide by UN resolutions calling for both sides to negotiate over their sovereignty claims. See “Falklands step up oil quest through 2012,” May 25, 2011, United Press International (upi.com) and Christopher Thompson, “Rockhopper raises Falklands oil estimate,” *Financial Times*, August 15, 2011.

the end of 2010, Rockhopper Exploration more than doubled its oil estimates on its Sea Lion well in August 2011 to as much as 1.2 billion barrels (between 608 million and 1.2 billion barrels of oil, with a mid-range estimate of 1 billion barrels). The company now estimates it could deliver some 434 million barrels from Sea Lion, assuming a 40 percent recovery rate, up from a previous estimate of about 155 million barrels.⁷⁶ Rockhopper plans to start pumping oil by 2016, but will need some US\$2 billion to develop the field.⁷⁷ To raise such funds or to attract a larger partner, the company has recently announced a proposed development program for the Sea Lion field. Meanwhile, Borders & Southern and Falkland Oil and Gas have mobilized a rig to initiate an exploration campaign in the South Falkland Basin in 2012.⁷⁸

Falkland Island success encourages Argentina not only to pursue its own deep offshore play, but also to intensify its own geopolitical campaign against the U.K.-controlled islands. Argentina's attempted blockade has split the southern Atlantic shipping trade, forcing some operators to abandon Argentina and others to stay away from the Falklands. Tensions between the Argentine and Falklands governments even exploded into violence earlier in 2011 when dockworkers in La Plata, Argentina, responded to rumors that two Norwegian ships in the harbor had worked earlier for the Falklands. Argentina has also ceased collaboration with the U.K. on key southern Atlantic issues such as fisheries conservation. None of this was foreseen by the Falkland Islands at the time it made its decision to begin exploration.

Nevertheless, while the offshore industry is booming around the Atlantic Basin, and as the interpenetration of the equipment and services sectors across the southern Atlantic deepens and intensifies, the re-emergence of the Falklands/Malvinas sovereignty issue stands out as a potential geopolitical hurdle to further development of a southern Atlantic offshore oil ring and an Atlantic Basin energy system. These geopolitical tensions reveal the systems and governance deficits within the southern Atlantic.

⁷⁶ Christopher Thompson, "Rockhopper raises Falklands oil estimate," *Financial Times*, August 15, 2011.

⁷⁷ Latin America Energy Advisor, "U.K. Company Finds More Oil off Controversial Falkland Islands," *Inter-American Dialogue*, Washington, DC, September 11–16, 2011.

⁷⁸ "Latin America — events to watch in 2012," *Upstream Insight*, Wood-Mackenzie, January 2012.

On the other hand, they also underline the enormous potential of the opportunities forgone as a result of this geopolitical brake upon the development of the energy systems of the region. The dispute, which diplomatically partially divides North from South, could even stimulate the formation of a “southern Atlantic” consciousness, perhaps to the detriment of any potential wider Atlantic Basin system.

Recent developments in Brazilian pre-salt production, on one hand, and in the consolidation of an African Atlantic oil rim, on the other, allow us to envision a deep offshore space and culture of the southern Atlantic, building upon traditional ties between Brazil and Atlantic Africa in the oil sphere — even if the competing high hopes for the Argentine offshore and the Falkland/Malvinas Islands never materialize. The notion of a “black swan” swimming into the northwestern African offshore (Mauritania, Morocco) or even into the far southwestern area of the Atlantic Basin (Argentina, the Falklands/Malvinas) completes the vision, making a “southern Atlantic offshore oil ring” — and its contribution to the consolidation of an Atlantic Basin energy system — all the more easy to imagine, even if many hurdles remain.

However, the most significant new trend in the hydrocarbons upstream, with potentially even more importance than the new dynamism of Atlantic Basin offshore oil, has been the swift emergence of unconventional gas — particularly shale gas — onto the global energy horizon. Shale gas could potentially transform the energy economics and geopolitics of the Atlantic Basin, where, beyond the pioneering United States, the “shale revolution” is most likely to embrace both the Southern Cone (especially Argentina) and South Africa.

Over the past decade, technological advances achieved by the U.S. gas industry — particularly hydraulic fracturing (known colloquially as “fracking”) and horizontal drilling — have rendered vast amounts of natural gas that is trapped in underground shale basins economically viable to produce. These new production techniques have driven down the costs of producing shale gas dramatically. Current average production costs for shale gas vary among regions in the United States and depend on a number of other factors, but in the recent past they have tended to range

between \$2 and \$3 per thousand cubic feet (mcf) of gas — or around one-half to one-third of the production cost currently associated with new conventional gas wells in the United States.⁷⁹

These lower production costs have sparked an unexpected boom in U.S. shale gas production, which, according to the IEA, rose from 12bcm (424bcf, or 1.17bcf/d) in 2000 to 45bcm (1.6tcf or 4.33bcf/d) in 2009.⁸⁰ By 2011, U.S. shale gas production had, according to some estimates, soared to 10 bcf/d — equivalent to 20 percent of total U.S. natural gas production. Furthermore, a 2010 MIT study, “The Future of Natural Gas,” estimated that shale gas production from five major plays in the United States would double by 2015 (to 20bcf/d) and triple (to 30bcf/d) by 2030.⁸¹ With 4 percent growth annually, shale gas is projected to be the largest contributor to the estimated growth in natural gas production and will account for 46 percent of total U.S. natural gas production by 2035.⁸² By that time, unconventional gas (including tight gas and coal-bed methane, along with shale) will constitute most of the United States’ natural gas output (see Figure 16), whereas gas overall (declining conventional plus rising unconventional) will increase its share of the national primary energy mix from the current 20 percent to 40 percent.⁸³

⁷⁹ “Full-cycle” shale production costs, which include the cost of capital (or the rate of return), were around \$5.60 per thousand cubic feet in North America by 2011. See Simon Mauger and Dana Bozbiacu, “How Changing Gas Supply Costs Leads to Surging Production,” *Ziff Energy White Paper*, Ziff Energy Group, Calgary, April 2011.

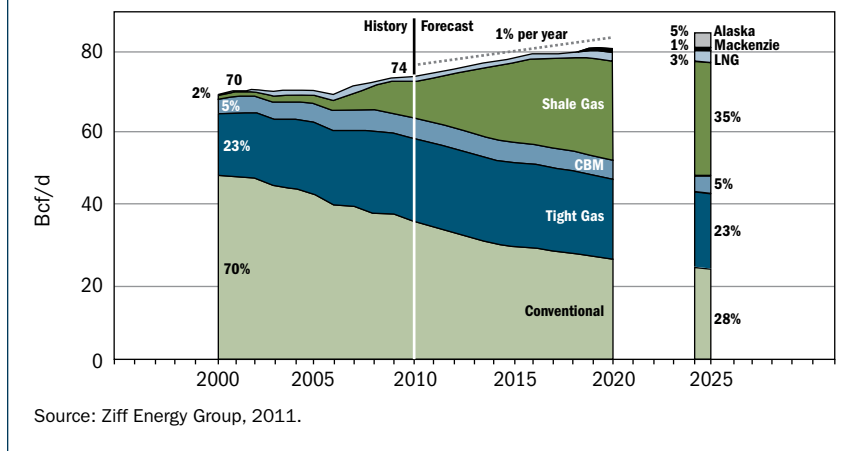
⁸⁰ IEA, *World Energy Outlook 2010*, International Energy Agency, Paris, November 2010.

⁸¹ See John Deutch, “The Good News About Gas: The Natural Gas Revolution and Its Consequences,” *Foreign Affairs*, January/February 2011.

⁸² EIA, *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*, U.S. Department of Energy, April 2011.

⁸³ See Derek Brower, “The way out of the global gas glut,” *Petroleum Economist*, December 2010, and MIT, “The Future of Natural Gas,” 2010 (cited from Deutch, op. cit.).

Figure 16. Shale Production Takes Over from Conventional Gas, U.S. Projections (2000–2025)



The evolution of the shale gas revolution in the United States (with technological innovation stimulating a reduction in production costs, which in turn led to a significant increase in the production of shale gas) has provoked what one analyst has called “perhaps the greatest shift in energy-reserve estimates in the last half century.”⁸⁴ In 2007, the United States had 250tcf of “proven” natural gas reserves, according to the EIA, with 22tcf of proven reserves of all types of unconventional gas (less than 10 percent of the total). By the following year, proven reserves for all unconventional gas had jumped to 33tcf.⁸⁵ That figure had nearly doubled to 61tcf by 2010, with shale gas accounting for 21 percent of overall U.S. natural gas reserves, the highest level since 1971.⁸⁶ In 2011, “technically recoverable” U.S. shale gas resources (a larger, more inclusive category than “proven reserves”) were estimated to be 862tcf, between one-quarter and one-third of the total U.S. domestic natural gas resource base (i.e., “technically recoverable reserves”), and more than half of “lower 48 state” onshore gas resources (see the following section on Shale Gas Potential in the Atlantic

⁸⁴ Deutch, op cit.

⁸⁵ See Deutch, op. cit.

⁸⁶ The MIT “Future of Natural Gas 2011” study estimates that the recoverable shale gas resource in the United States is approximately 650tcf (based on low and high projections of 420tcf and 870tcf, respectively). Approximately 400tcf of this U.S. shale gas resource base “could be economically developed with a natural gas price at or below \$6/MMBtu at the wellhead.”

Basin).⁸⁷ Nevertheless, however, in early 2012, the U.S. Department of Energy abruptly adjusted these estimates downward by more than 40 percent (from well over 800tcf to 482tcf), at least for the United States (other national estimates remained the same).⁸⁸

This boom in unconventional gas production and reserves in the United States, driven primarily by shale gas, coupled with currently moderating demand stemming from the global recession and the recent and imminent arrival of new LNG capacity (on both the supply and demand sides), has contributed to a sudden and unexpected global “gas glut.” The supply overhang of some 200bcm (principally reflecting excess LNG capacity) will exercise a number of strategic pressures upon the global energy system over the coming years, from changes in gas market practices and energy policies — which traditionally have linked gas prices to those of oil — to shifts in relative geopolitical influences, which until recently had favored sellers over buyers. Such pressures and shifts will be considered further in sections below, but first let us assess the potential for shale gas within the Atlantic Basin.

Although no reliable estimates for shale gas potential beyond the United States have been available until recently, the latest studies suggest that it could be enormous.⁸⁹ At the global level, technically recoverable shale gas reserves are now estimated to be 6,622tcf (862tcf in the United States, plus 5,760tcf located in 32 other countries).⁹⁰ These global technically recoverable reserves of shale gas form part (more than 25 percent) of a larger and more speculative category of total shale gas resources — known as total global “risky gas in place” — which comes to 25,300tcf (3,284tcf in the United States and 22,016tcf in the rest of the world).

⁸⁷ See EIA, *op. cit.*.

⁸⁸ “U.S. shale gas reserve estimates plummet,” January 26, 2012, Pennenergy.com.

⁸⁹ See EIA, *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*, U.S. Department of Energy, April 2011, and H-H Rogner, “An Assessment of World Hydrocarbon Resources,” *Annu. Rev. Energy Environ.*, No. 22, 1997.

⁹⁰ EIA, *op. cit.* This EIA study is the most recent, comprehensive and reliable to date. Nevertheless, its estimates only include the United States and 32 other countries, excluding parts of the Andean zone (Ecuador and Peru), all of sub-Saharan Africa except South Africa, most of southern Europe, all of the Middle East, Central Asia, and Russia, as well as Southeast Asia. One interesting implication of the broad nature of these exclusions is that the reference estimates used for shale gas potential globally and within the Atlantic Basin could be conservative, underestimating its ultimate potential impacts. However, U.S. shale gas estimates have recently been adjusted downward significantly. See note 4.

Meanwhile, before the formal inclusion of most of these new large technically recoverable shale gas reserves (6,600tcf), the world's total proven reserves of natural gas at the end of 2009 were about the same, or some 6,600tcf, whereas the world's technically recoverable gas resources totaled roughly 16,000tcf (including only small amounts of shale gas). When the identified technically recoverable shale gas resources are added to conventional gas resources, the world's total technically recoverable gas resources increase by more than 40 percent (to 22,600tcf).⁹¹ Assuming that the rest of the world follows the United States in the exploitation of shale gas, proven reserves of shale gas would therefore tend to rise to similar levels as a percentage of total world proven reserves (of all forms of natural gas). However, such projected increases in the weight of shale gas in world gas production, proven reserves, and ultimate resources are probably conservative, as these estimates do not include shale gas assessments for many of the world's most significant current and potential gas producers, many of which are in the Atlantic Basin.

The EIA has identified a number of potential shale gas producers within the Atlantic Basin. The first sub-group includes France and Poland in Europe, and Morocco and South Africa in Africa, “countries that are currently highly dependent upon natural gas imports, have at least some gas production infrastructure, and their estimated shale gas resources are substantial relative to their current gas consumption.”⁹² For these countries — traditional gas importers — shale gas could significantly alter their future gas balances, lower their external gas dependence, and increase the level of gas penetration into the energy mix (producing an additional potential beneficial effect on carbon emissions). Such incentives will operate as powerful stimuli for the development of shale gas in such countries. In addition, South Africa's shale gas resource endowment is even more strategically interesting, as it may be attractive as a cheap domestic feedstock for the country's existing gas-to-liquids (GTL) and coal-to-liquids (CTL) plants. This strategically significant linkage between the budding upstream shale gas revolution in the southern Atlantic and the budding

⁹¹ See EIA, *op. cit.*, and Kiran Stacey, “U.S. Energy Dept: Shale adds 40 percent to global gas supplies,” *Financial Times*, June 4, 2011.

⁹² EIA, *op. cit.* Other countries, in a similar potential shale gas-producing subgroup (but only from beyond the Atlantic Basin), would include Turkey, Ukraine, and Chile.

downstream revolution of the gas-to-liquids sector, led by South Africa, will be explored further below (see section 2.4.3 on the Downstream and section 3.2 on South Africa).

The second subgroup of potential Atlantic Basin shale gas producers includes (in addition to the United States) Canada, Mexico, Brazil, and Argentina: countries where the estimated technically recoverable shale gas resources are large (above 200tcf) and significant natural gas production infrastructure is already in place, either for domestic consumption or export.⁹³ Existing infrastructure would facilitate the timely conversion of shale gas resources into production, but could also lead to competition with other natural gas supply sources (as well as with renewables), requiring a special policy focus in order to optimize the potential carbon emissions savings stemming from the shale revolution. Furthermore, the upstream-downstream linkage between shale gas production and GTL production for the transportation fuels market is potentially available to these countries as well.

The Atlantic Basin's technically recoverable shale gas resources can be inferred from Figures 17–18. Following the same Atlantic Basin categories (broad, intermediate, narrow, and approximate average applied above in sections 2.1 and 2.2 on Atlantic Basin Oil and Natural Gas), the EIA global shale gas assessments reveal that the “broad Atlantic” holds 4,779tcf of technically recoverable shale gas reserves (or 72 percent of the world total); the “intermediate Atlantic” (stripping out countries without a direct coastline on the Atlantic) has 3,857tcf (or 58 percent); the adjusted “narrow Atlantic” (splitting dual-basin country reserves in half) has 2,667tcf (or 40 percent); and the “approximate” Atlantic Basin (the average between the “broad” and the “narrow”) holds around 56 percent of the world's total technically recoverable shale gas reserves (compared with only 12 percent of the world's proven conventional gas reserves; see section 2.3.2 on the Natural Gas Map). Such a promising panorama for the Atlantic Basin's shale subsystem, in absolute and relative terms, suggests that shale gas could be a key vector — along with deep offshore oil, LNG, GTL technology,

⁹³ EIA, *op. cit.* Other countries from the broad Atlantic and from beyond the Atlantic Basin would include Libya and Algeria, and China and Australia, respectively.

renewable energies, and transnational electricity grid integration — for the further development of the Atlantic Basin energy system.⁹⁴

However, it is not yet clear exactly where, to what degree, and at what pace shale gas exploration and production will proceed around the Atlantic Basin. Despite the potentially significant economic, environmental, and strategic benefits of shale gas, there are lingering uncertainties surrounding production costs, local “not-in-my-backyard” (NIMBY) resistance, and potential environmental damage (including threats from hydraulic fracturing to the quantity and safety of water supplies, along with “fugitive” methane emissions) that may slow or fragment the progress of shale gas production within the Atlantic Basin. Although Poland in the “broad” Atlantic and the U.K. in the “narrow” will likely push the development of shale gas (and in the Polish case, IOCs have already been allowed to begin prospecting), France has temporarily banned shale gas exploration, as has the Canadian province of Quebec.

Although Argentina (and probably, if to a lesser degree, Brazil) will likely begin to develop significant amounts of shale gas relatively quickly, a question mark still hangs over South Africa’s development of the shale gas of the Karoo Basin, at least in the short run, due to environmental, NIMBY, and cost uncertainties — even as the country’s GTL prowess cries out for domestic shale gas development (see section 3.2 on South Africa). The continued feasibility of the shale gas revolution is even being questioned in the United States (currently the world’s single major shale gas producer), where public concerns over the dangers posed to water supplies by fracking are generating increased pressures for tighter and more robust regulatory oversight. Nevertheless, an increasingly higher percentage of the Atlantic Basin’s future shale gas production is more likely to occur within the southern, as opposed to the northern, Atlantic. Much will depend on how the fracking and fugitive emissions controversies are resolved in the United States.

Argentina probably has the most powerful incentives, on the both the supply and demand sides of the equation, to develop shale gas more quickly than any other country (besides the United

⁹⁴ Although extra-Atlantic shale gas reserves could be augmented by future assessments of Russia, Central Asia, the Middle East, and Southeast Asia, the Atlantic Basin reserves themselves could be augmented by future assessments of the shale potential of southern Europe and sub-Saharan Africa.

Figure 17. Global Shale Gas Resources, “Technically Recoverable” Reserves by Country (Tcf), 2011

Continent	Region	Country	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)
North America	I. Canada		1,490	388
	II. Mexico		2,366	681
	Total		3,856	1,069
South America	III. Northern South America	Colombia	78	19
		Venezuela	42	11
		Subtotal	120	30
	IV. Southern South America	Argentina	2,732	774
		Bolivia	192	48
		Brazil	906	226
		Chile	287	64
		Paraguay	249	62
		Uruguay	83	21
	Subtotal	4,449	1,195	
Total		4,569	1,225	
Europe	V. Eastern Europe	Poland	792	187
		Lithuania	17	4
		Kaliningrad	76	19
		Ukraine	197	42
		Subtotal	1,082	252
	VI. Western Europe	France	720	180
		Germany	33	8
		Netherlands	66	17
		Sweden	164	41
		Norway	333	83
		Denmark	92	23
		U.K.	97	20
	Subtotal	1,505	372	
	Total		2,587	624
Africa	VII. Central North Africa	Algeria	812	230
		Libya	1,147	290
		Tunisia	61	18
		Morocco*	108	18
		Subtotal	2,128	557
	VIII. South Africa		1,834	485
Total		3,962	1,042	
Asia	IX. China		5,101	1,275
	X. India/Pakistan	India	290	63
		Pakistan	206	51
	XI. Turkey		64	15
	Total		5,661	1,404
Australia	XII. Australia		1,381	396
Grand Total			22,016	5,760

*Includes Western Sahara & Mauritania

Source: EIA, World Shale Gas Resources, April 2011.

States) within the Atlantic Basin. As with oil, Argentina was once a large producer and net exporter of natural gas (mainly to Chile and Brazil), but its gas reserves and production levels have fallen recently, pushing it into net gas-importer status in 2008. However, with extensive gas infrastructure (e.g., pipelines) already in place, Argentina is set to remain a large consumer of natural gas (which currently dominates the country's primary energy mix, accounting for 50 percent of total energy consumption). Therefore, unless shale gas production rises, Argentina will be forced to either import large amounts of LNG in addition to its pipeline imports from Bolivia or suffer an increasingly acute internal energy constraint on its rate of economic growth.

Argentina's proven reserves of natural gas declined by 50 percent during the past decade, to 13.3tcf (0.4tcm) in 2009, and fell further to 12.2tcf in 2010. Gas production peaked in Argentina at 4.5bcf/d in 2006, falling to 4.3bcf/d in 2008 (when it slipped into net gas-importer status) and further to 3.9bcf/d by 2010.⁹⁵ Nevertheless, the development of Argentina's significant shale gas resources could reverse these trends.⁹⁶ The country has some 774tcf of technically recoverable shale gas resources, the third-largest in the world after the United States and China. These technically recoverable shale gas reserves (408tcf, 95tcf, 108tcf, and 164tcf in the Neuquén, San Jorge, Austral-Magallanes, and Parana-Chaco basins, respectively; see Figure 18) come to nearly 12 percent of the world's total, and more than 50 times the country's current proven reserves of gas.⁹⁷

Shale gas exploration has only recently become attractive in Argentina with the revision of the country's gas pricing structure. As of mid-2010, the government has allowed unconventional gas production to be sold at higher prices (\$4-\$7/MMBtu compared to around \$1-\$3 generally). This new "Gas Plus" policy has produced rapid and positive results. Dozens of projects to exploit Argentina's unconventional tight sand and shale gas resources went under review or began development. Initial shale exploration drilling is already under way in the Neuquén Basin (where a

⁹⁵ See BP Statistical Review of World Energy, 2011.

⁹⁶ According to some sources, Argentina already produces more than 230 million cubic feet of unconventional natural gas per day (MMcf/d), or about 5 percent of total production.

⁹⁷ EIA, op. cit.

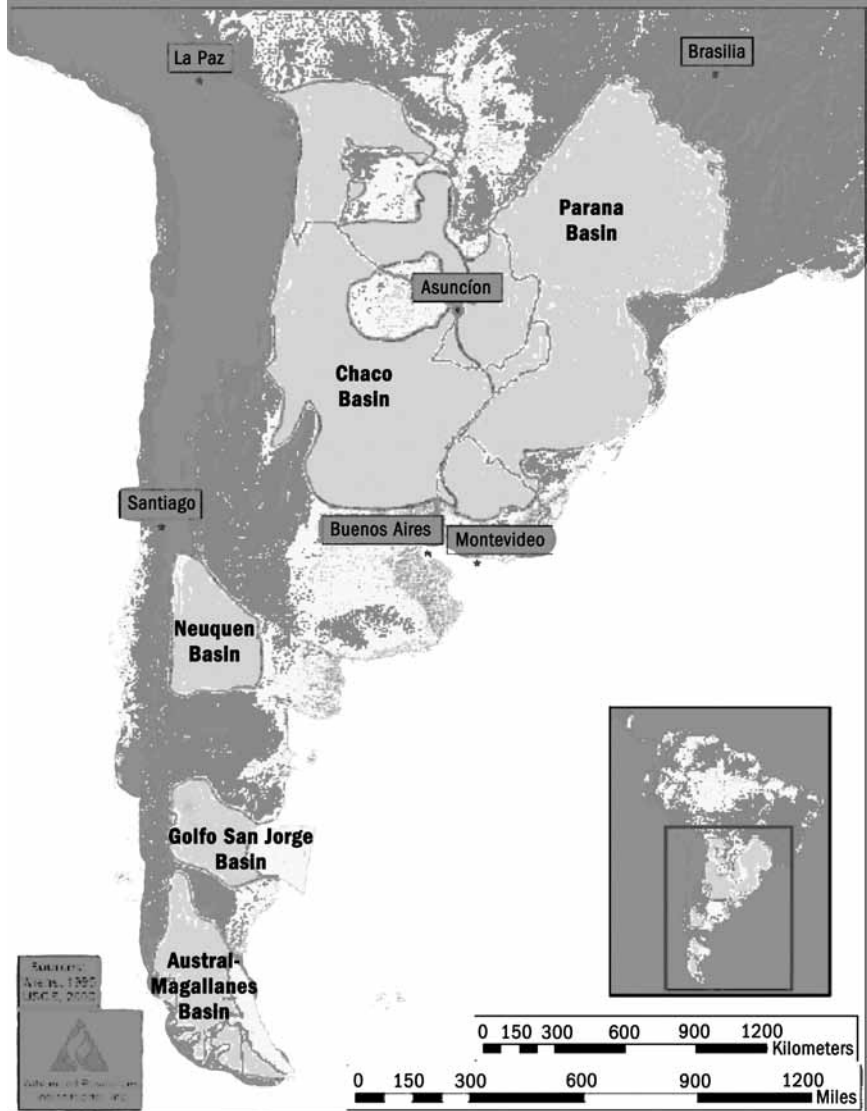
gas transportation and field services infrastructure is already in place), led by Apache and YPF (partners in the development of unconventional gas in the Neuquén and Austral basins). A slew of other companies, including ExxonMobil, Total, Apco Oil & Gas, American Petrogas (API), and Pluspetrol, are also attempting to take advantage of the more attractive fiscal terms now on offer from Argentina's government.

Already, in December 2010, then-Repsol TPF announced a 4.5tcf shale gas discovery in the tight sandstone reserves of the Loma de La Lata conventional gas field in Neuquén Basin. The company and the Argentine government both speculate that the shale gas reserves of the Neuquén Basin are more than 250tcf. With annual gas consumption of 1.5tcf and its total proven, documented gas reserves at about 12tcf, the then-Repsol YPF discovery is far more significant for Argentina than was the Barnett shale play for the United States. API followed in January 2011 with a smaller (100tcf) shale discovery of its own.

Nevertheless, the Argentine government's recent nationalization of YPF from Spain's Repsol (which was forced to relinquish 51 percent of the company) has cast a cloud of uncertainty across the country's investment horizon. While a number of international oil companies (such as Sinopec, ExxonMobil and Total) have expressed interest in partnering with the newly independent YPF to develop the shale gas of the Neuquen Basin, it is not yet clear whether such firms will be willing to inject the kind of sums deemed necessary (some \$20 billion in investment is said to be required), given the Argentine government's increasingly interventionist proclivities.

The shale gas revolution has been real, at least in the United States. The extension of significant shale gas production, however, to other countries in the Atlantic Basin and beyond could transform the future of global economic, geopolitical, and energy-climate dynamics (see the section below on the Repercussions of Shale Gas). Nevertheless, this revolution is at a crossroads, its future clouded by uncertainty around a number of economic doubts and environmental fears.

Figure 18. Shale Gas Basins in Argentina, Uruguay, Paraguay, and Brazil, 2011

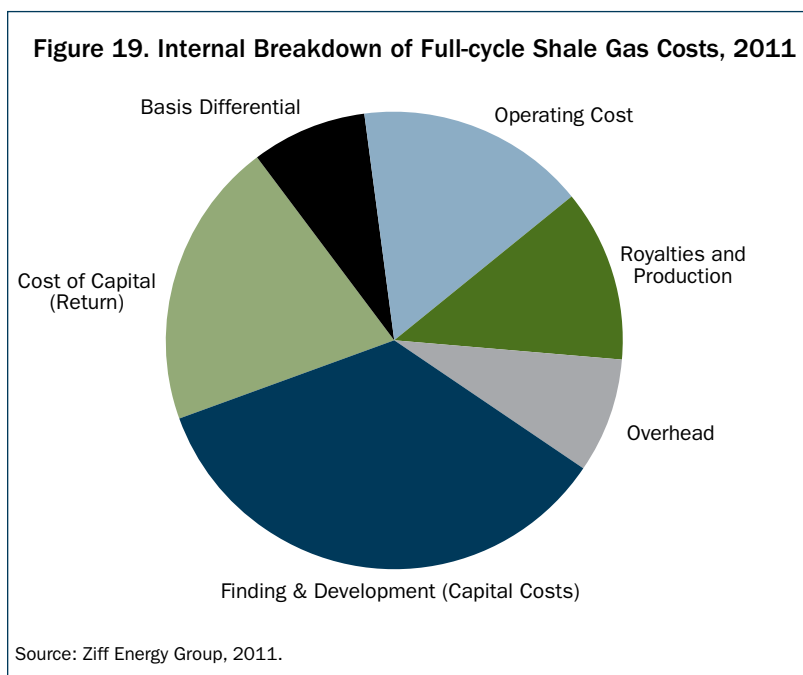


Source: EIA, 2011

A lack of sufficient geological information and concrete exploration drilling test data outside of the United States complicates the future of global unconventional gas production, at least for the next few years. The biggest casualty of this dearth of information is any sense of confidence when estimating the production costs of shale gas in countries beyond the United States. The EIA's most recent assessment of global shale gas resources estimates "risky gas in

place” and “technically recoverable” gas, but it did not even attempt to estimate production costs internationally.⁹⁸

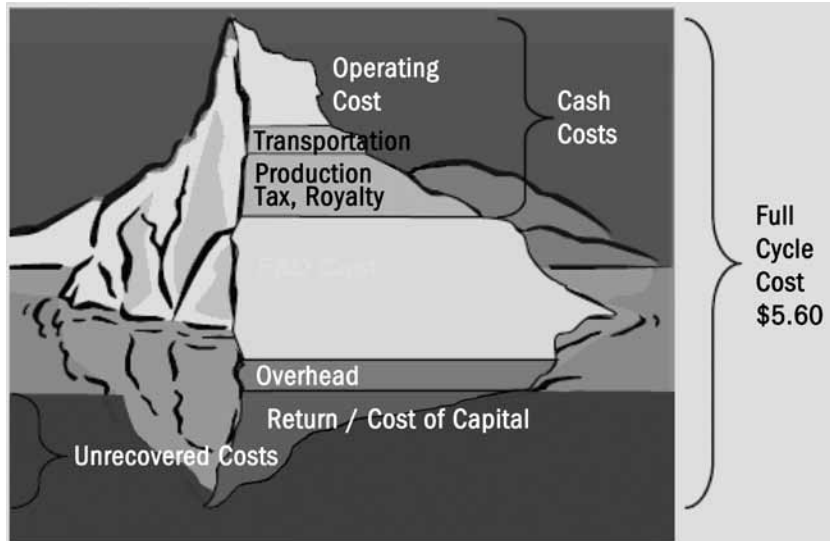
Because geological characteristics (e.g., depth and thickness of fields) vary widely across basins even within the same country, as do a number of other economic, geographical, and policy factors (including the availability of existing gas infrastructure, and the availability and cost of adequately trained labor and required equipment such as rigs and pumping equipment, among others), shale production costs tend to vary widely across different basins, countries, and continents. In the United States, for example, shale production costs currently oscillate by up to 50 percent across basins. Differential costs across North American basins typically account for some 12 percent of “full-cycle shale gas cost” (a broader measure of costs that includes the opportunity cost of capital, or the rate of return on investment; see Figures 19 and 20). But relatively accurate estimated production costs for each shale gas basin will be necessary to determine any basin’s or country’s proven shale gas reserves. Only proven reserves will bring forth sufficient and sustained financing for adequate investment in exploration, development, and production.



⁹⁶ See EIA, *op. cit.*

Countries with significant domestic gas infrastructures, such as the United States and Argentina, will be able to minimize costs through more intense shale gas exploration and development, which generates better data, economies of scale, learning curves, continued technological innovation and adaptation, and, as a result, lower costs. They will also be more likely to overcome local NIMBY and public environmental resistances to shale gas development, given that their long histories as significant gas producers — even if recently in decline — has fostered a culture of tolerance for significant oil and gas drilling. However, countries without much domestic gas infrastructure, such as South Africa, will initially face greater uncertainty with respects to production costs. Not only will such countries need to prospect shale basins more intensively in order to determine the economic feasibility of exploitation, but also they must deal with local NIMBY and international environmental resistance, which in countries without a significant current physical infrastructure or a history as a gas producer will likely be strong, if not necessarily insurmountable. Such resistance will tend to at least slow the progress of exploration and production (see the section on South Africa).

Figure 20. Full-Cycle Costs for Shale Gas Production, North America, 2011



Source: Ziff Energy Group, 2011

However, the recently released MIT study “The Future of Natural Gas” concluded: “The environmental impacts of shale development are challenging but manageable.” The study further concluded, however, that “it is essential that both large and small companies follow industry best-practices; that water supply and disposal are coordinated on a regional basis; and that improved methods are developed for recycling of returned fracture fluids.”⁹⁹ The MIT group recommended, among other measures, that:

“A concerted coordinated effort by industry and government, both state and federal, should be organized so as to minimize the environmental impacts of shale gas development through both research and regulation. Transparency is key, both for fracturing operations and for water management. Better communication of oil- and gas-field best practices should be facilitated. Integrated regional water usage and disposal plans and disclosure of hydraulic fracture fluid components should be required.”¹⁰⁰

Even before the most recent controversy over shale gas economics emerged, however, another little-known critique was being mounted by environmentalists, casting doubt over the wisdom of pursuing shale gas. Conventional natural gas has long been considered the cleanest and most climate-friendly of the fossil fuels, generating on average only 50 percent of the carbon emissions of coal and only two-thirds of those of oil. As such, many analysts have argued that only with the massive rollout of a “gas bridge” —

⁹⁹ “There has been concern that these fractures can also penetrate shallow freshwater zones and contaminate them with fracturing fluid, but there is no evidence that this is occurring.” This study blames known instances of methane contamination on a small number of substandard operations, and encourages the use of industry best-practices to prevent such events from recurring. See the MIT Energy Initiative, “The Future of Natural Gas: An Interdisciplinary MIT Study,” MIT, 2011.

¹⁰⁰ Interestingly, the MIT study also recommended that “the U.S. should support unconventional natural gas development outside the U.S., particularly in Europe and China, as a means of diversifying the natural gas supply base.” The major recommendations included in the executive summary of the recent EIA world shale study made no mention of the potential for the United States to support unconventional gas development in the southern Atlantic, despite the fact that the EIA recently estimated that Argentina and South Africa possessed the third- and fifth-largest shale gas reserves in the world, behind the United States and China, but far ahead of any potential producer in Europe. This could be because the MIT group perceives a sufficiently high regulatory and political risk premium in Argentina and South Africa. This would be understandable given the reigning perceptions of these countries in the northern Atlantic, although our study would argue that recent events on the ground (as well as energy security imperatives) suggest that such risk should be priced at a much lower level. It is also possible that the MIT group is simply underestimating the potential of the southern Atlantic in general, a much more alarming possibility. Our study, nevertheless, should correct for that.

displacing first coal and then oil — to a low-carbon economy will the world be able to stop average global temperatures from rising in this century more than 2 degrees Celsius over pre-industrial levels.

Nevertheless, recent scientific analysis has pointed to the potential for fugitive emissions of methane — a far more troubling greenhouse gas with higher heat-trapping capacity, particularly over the first 20 years, than carbon dioxide — to escape during the fracking process. Even the U.S. EPA has recognized that shale gas emits far larger amounts of methane than conventional gas. A 2011 peer-reviewed study by Cornell University claims to be the first comprehensive analysis of the life-cycle greenhouse gas footprint of shale gas. It concludes that once methane leakage and venting impacts are included, the life-cycle greenhouse gas footprint of shale gas is far worse than that of coal and fuel oil.¹⁰¹ Should such findings be confirmed, they will dissolve what is — for many shale supporters around the world — the central *raison d'être* of the shale gas revolution: its potential to slow the rise of carbon emissions. This emissions “cloud of doubt” is probably the most troubling of all the risks and uncertainties surrounding the future of shale gas.

Still, it is probably too early to write off the shale gas revolution. After all, most new energy forms experience growing pains, along with their early booms and busts, in both price and production. This was true of oil during the 19th century, and it has recently been demonstrated again in the renewable energy sectors. Not all energy forms overcome such early instability, but shale gas has demonstrated that technological innovation can reduce costs, particularly as the sector moves to scale and passes along the various learning curves. More than a few abruptly exhausted wells in a single Texas basin will need to be demonstrated in order to roll back the recent shale gas trajectory. The history of the oil industry, which has endured five different “peak oil” hysterias along the way to its current moment of bonanza, is instructive in this regard.¹⁰²

¹⁰¹ “The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20 percent greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.” See Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, “Methane and the greenhouse-gas footprint of natural gas from shale formations,” *Climate Change Letters*, 2011.

¹⁰² See Daniel Yergin, “There Will Be Oil,” *Wall Street Journal*, September 17, 2011.

Furthermore, the shale gas boom of recent years may have resembled a bubble, and certain plays may even have had something in common with Enron's duplicity, but the shale boom was also bound up with the long financial boom that flourished before the crash. The shale boom fed upon the same speculative fever, and was driven by the same cheap money, that finally blew up the great Wall Street Bubble of the mid-2000s. The real and anticipated rise in shale gas supply was only partially responsible for the collapse in U.S. Henry Hub gas prices from more than \$12 per thousand cubic feet in the summer of 2008 to less than \$4 by the following summer (see Figure 21). The recession of 2008–2010 — provoked and intensified by the financial crisis — was also a significant partial cause of the new glut and the 2009 collapse in gas prices, killing off much consumer and industrial demand. The current global gas glut was generated from both the supply and demand sides. However, outside the United States (i.e., in Europe and Asia), the more dominant influence has been a general weakening of the demand trend, which — after years of strong investment in global LNG capacity brought on line by half a decade of high and rising prices — left a large supply overhang (as much as 200bcm) in the global gas market (see the section below on Repercussions of the Shale Revolution).

Although the glut is expected to last well into the middle term, demand will continue to rise, steadily eating away at the overhang. Enron-like (intentionally misreported production and reserves) and Ponzi scheme behavior (speculative purchases of wells with less than demonstrated value that are “turned over” at a higher price on the basis oversold “potential”) do not by themselves discredit the potential of the shale gas revolution. However, such behavior does underscore the need for robust and effective regulation of the shale gas industry, over which there is now a growing consensus. But regulation of the shale gas industry will not be easy, particularly given the difficulties of designing appropriate regulatory regimes for both large and small firms within the same market. In the context of the Atlantic Basin, such concerns point to an opportunity for southern Atlantic collaboration in the sharing of technical, environmental, and safety “best-practices” around the basin, and in the exchange of regulatory experiences and perspectives.

The shale gas boom caught most of the world's large conventional gas producers off guard, as did the 2008–10 recession. The gas world was already being swept up by a major wave of LNG expansion during the mid-2000s, with many gas exporters — particularly Qatar, now the world's leading LNG exporter — ramping up liquefaction capacity to meet expected strong future demand from China and the United States (on the brink of becoming a large net importer), where the anticipation of significant future gas imports, in turn, was building up regasification/import capacity. Large gas producers dependent on pipelines (such as Russia) were even starting to consider the inclusion of LNG in the construction of their “optimal gas investment strategy” for maximizing producer rents (at the time, Russian President Vladimir Putin was speaking of a “Gas OPEC”), and, after years of viewing LNG as a competitor to pipelined gas that could eat away at producer rents, many producer states have now at least recognized a potentially important future role for LNG exports in their gas strategies.

Before the arrival of shale, the principal gas revolution on the horizon was the potential for LNG to unify the world's major regional gas markets into a deep and liquid global gas market. The global gas market would then exhibit much more unified global prices as a vigorous spot market would arbitrate regional disparities, making it more similar to the global oil market. Such a development would allow gas prices, traditionally linked to oil prices through the conditions typically set in long-term contracts, to “delink” from the economic and geopolitical dynamics of global oil, as its global price would more autonomously express the distinct dynamics of the gas world (which overlaps, but is not even close to being identical to, that of oil). This “delinking” would, in turn, allow gas to compete more effectively with both coal and oil, and the “gas revolution” — which Daniel Yergin and colleagues first announced more than a decade ago — would be on in full force. The prize for the global collective would be a cleaner “gas bridge”

to a low-carbon future, whereas the gas industry would win a much higher share of the world's future energy mix.¹⁰³

However, the LNG expansion wave was abruptly put on hold by the pincer development of 1) more abundant supply suddenly coming from U.S. shale production; and 2) a sudden drop in demand stemming from the global recession. This created a sudden “gas glut,” with a global supply overhang of some 200bcm by 2011 (half of that in Europe alone), equivalent to the combined gas demand of Africa and Latin America, and reflected principally by LNG overcapacity. Global LNG export capacity now stands at 283m tons a year (t/y), and import capacity has now reached 483m t/y.¹⁰⁴ However, most of the import capacity is concentrated in Japan, South Korea, and Spain, with the rest distributed across the advanced countries, where consumption growth is expected to be weak. Meanwhile, by 2013 another 100 million t/y (or 130bcm/y) of LNG supply capacity is due to come on stream, with another 30 million t/y to follow by 2015. The IEA predicted in late 2010 that the gas glut will last for several years — until as late as 2035 — even if governments impose some further limitations on carbon emissions.¹⁰⁵

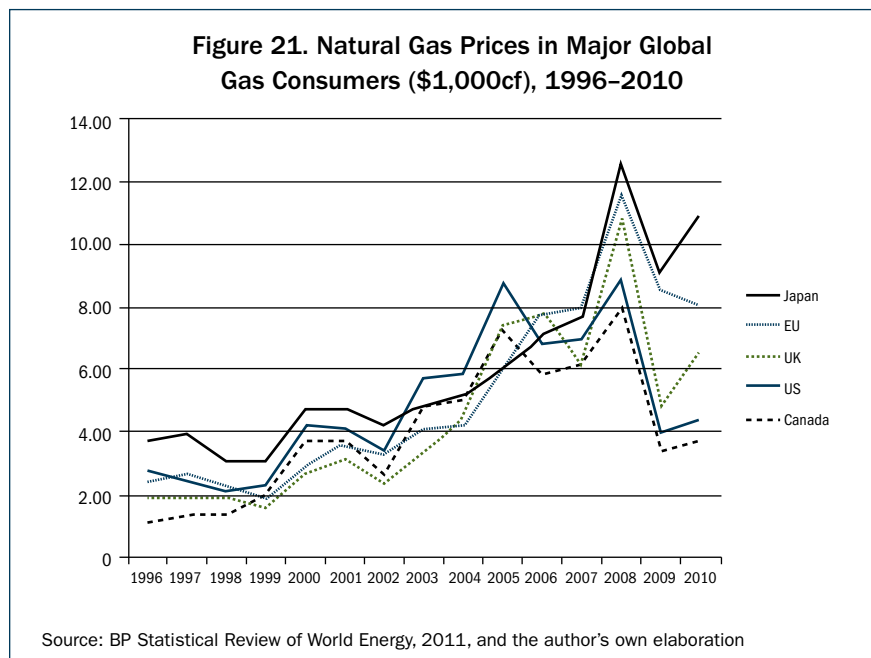
In the United States, the shale gas revolution has transformed the gas scenario almost overnight, from an envisioned future of the country as the largest LNG import market to a new status quo as a self-sustaining gas producer, and as a possible growing net gas exporter. This collapse in LNG import demand has underpinned the supply side of the gas glut, provoking some U.S. companies

¹⁰³ The gas revolution might be the only practical way, in the end, to disarticulate the resistance of oil companies to a rapid shift to a low-carbon economy, which would include a significant ramping up of renewable energies. The gas revolution could potentially channel the resources, talent and “human energy” of the majors — currently dedicated to defending at all costs oil's share of the world's primary energy mix — into a realistic global strategic formula for future energy investment capable of achieving a reduction of carbon emissions in time to avoid serious threats to the integrity of the international system and the planet's biosphere. Indeed, a number of oil companies are now shifting to a gas-dominant portfolio and a gas-led strategy. Leading actors in the shale gas revolution, such as Shell, are positioning themselves as “gas companies” as opposed to “oil companies.” ExxonMobil is following in the same direction, if less radically. Meanwhile, the one-time Repsol-YPF — until recently the new swashbuckling “dark horse” of the Atlantic oil world (before pre-salt, this moniker would have gone to Petrobras) — had always had more gas than oil in its upstream portfolio, even though it had its origins as a downstream oil company in Spain.

¹⁰⁴ Petroleum Economist LNG Data Centre, 2011.

¹⁰⁵ Derek Brower, “The way out of the global gas glut,” *Petroleum Economist*, December 2010.

(such as Freeport LNG and Cheniere Energy) that had invested heavily in LNG import capacity to now consider additional new investment to convert their facilities into LNG export capacity, which potentially could add further to the glut on the export infrastructure side of the market. Since the summer of 2008, as the shale gas revolution boomed and as the global recession began, natural gas prices have fallen by more than 50 percent in North America, significantly more than in Europe or Asia (see Figure 21). Additional downward price pressure is still built into the current gas project pipeline. Qatar, for example, is expected to soon have 77 million t/y of LNG output capacity (equivalent to more than 5mbd of oil) and to control nearly 30 percent of the world’s seaborne LNG trade. The imminent addition of Qatar’s two new large LNG trains will likely provoke yet another fall in the spot price of gas, a possibility that would only intensify the economic pressures currently straining the large exporters of gas to Europe.



The shale gas revolution seems to have forestalled the fate of the United States, which is now the world’s largest gas producer (as of 2009, when it overtook Russia), and kept it from sliding further into production decline and increasingly import-dependent status. Not only does this new “gas dynamic” — first introduced by LNG, then transformed by the new possibilities of shale, and finally reinforced

by temporarily weakening demand — have the potential to do the same for other countries in the Atlantic Basin (such as Argentina), but also it has already delivered enormous benefits to consumers in the basin during a period otherwise defined by high energy prices. Furthermore, even before a single country has followed the United States into actual shale gas production, the shale gas revolution is already exerting a profound influence on global energy geopolitics. If the shale gas revolution maintains momentum and spreads internationally, the new gas dynamics could become structurally embedded within the energy economy of the Atlantic Basin.

First, the earlier-mentioned incipient revision of gas strategies among the large traditional gas exporters, under way from the mid-2000s until the recession, has had to undergo yet further rethinking. On the eve of the global financial and economic crisis, the Russian state-owned gas company, Gazprom, predicted that European gas prices would triple to \$1,500/000cm (\$42/000cf). Nevertheless, the price of Russian gas in Europe fell from around \$500/000cm (\$14/000cf) during the summer of 2008 down to \$308/000cm (or \$8.62/000cf). By 2009, Gazprom had announced that it would develop LNG export capacity, targeting 25 percent of the world's LNG market by 2020. However, this goal of rapid LNG expansion has been effectively put on hold, given the unexpected drop in gas prices provoked by the development of shale gas in the United States. Already the Shtokman field in the Barents Sea, intended to export LNG, has been delayed yet again (this time indefinitely, dimming prospects, to at least some degree, for rapid exploitation of Arctic oil and gas). Meanwhile, total Russian exports to the EU and Turkey fell by 25 percent in the third quarter of 2010. In response, Russia has lowered its production targets, rendering the country's 140bcm export target overly optimistic.

Gazprom has recently shown signs of adapting to the gas glut by abandoning geopolitical for more commercial tactics, lowering their prices, and concentrating on current and future market share. Should the volumes of shale gas moving into the Atlantic Basin become more significant in the short- to midterm future, Russia may be forced to make this tactical shift in gas policy a more permanent feature of its long-term strategy. To the extent that shale gas production expands into Europe (where Poland is on the path to become the first producer), the choice for Russia will be

clear: Either Gazprom continues with its policy of the past, despite the new shale-induced lower-price environment, and attempts to defend the old market model and pricing system (based on long-term contracts for pipelined gas exports to Europe at prices primarily linked to the price of oil), or it will need to compete with expanding shale gas production through a more flexible pricing system that would significantly modify the traditional model of oil price-indexed, long-term, take-or-pay contracts. The first option would risk losing market share to new shale producers, whereas the second would lead to a clearly positive outcome for consumers in Europe and beyond.¹⁰⁶ Although both options would imply a weakening of Russia's geopolitical influence over Europe, only the second opens up the possibility for Russia to both proactively insert itself within a new global energy economy and improve its political and economic relationships with Europe and the United States.

These economic pressures emanating from an increasing internationalization of the shale gas revolution would not only affect the geopolitical limitations of Russia. It would provoke a broader global shift in economic and geopolitical power away from other nationalist hydrocarbons exporters and toward the current net-importing states. This geopolitical shift would have even starker implications for countries (such as Iran and Venezuela) that have both nationalist energy policies and large reserves of gas that remain largely untapped. Under such an unfolding scenario, Iran might eventually decide to trade its recalcitrance on the nuclear issue (along with the attendant, if marginally declining, local political benefits) for an energy strategy that would pursue an increasing share in the gas markets of the West (along with its potentially enormous domestic economic benefits for Iran, to say nothing of reduced political instability in the Persian Gulf).

The potential impacts of the shale and LNG-induced gas glut on Venezuela are somewhat less clear. Mismanagement (however noble the current Chavez government might consider the cause) has provoked a notable decline in Venezuelan oil production and introduced enormous uncertainty around the prospect of Venezuela ever meeting its longtime production targets above

¹⁰⁶ See Maximilian Kuhn and Frank Umbach, "Strategic Perspectives of Unconventional Gas: A Game Changer with Implications for the EU's Energy Security," EUCERS Strategy Paper, King's College, London, May 2011.

5mbd. Nearly all of Venezuela's gas reserves — Latin America's largest — remain in the ground, as the country has flip-flopped back and forth between a forward-looking strategy based on LNG exports and another pursuing the chimera of a Great Southern Pipeline that would aspire to export future Venezuelan gas down to the centers of demand in the Southern Cone (while keeping its hand on the tap that supplies its neighbors with gas).

Mismanagement has also undermined the solvency of the Venezuelan state, leaving it highly vulnerable at a moment of moderating demand and collapsing gas prices in the Atlantic Basin. A well-managed Venezuela (still imaginable even under a future Chavez government) could take advantage of the various interlocking global gas trends to become an Atlantic Basin champion of a collective “gas bridge” energy strategy. However, a Venezuela that continues on its current trajectory is likely to become, at best, increasingly less relevant to the future of the Atlantic Basin energy system, or in the worst-case scenario, the source of a dangerous political and economic instability.

An important sign that such a shift is under way in the attitude and policies of the traditional conventional gas exporters has been the recent call from Russia and Qatar for the European Commission to heed the conclusions of a recent McKinsey study, commissioned by European Gas Advocacy Forum (which also includes ENI, E.On, GDF Suez, Shell, and Statoil). The report challenges the notion that renewable energies should constitute Europe's primary path for cutting its carbon emissions, at least in the short run, and concludes that Europe could save as much as €900 billion (\$1.25tn) and still meet its 2050 carbon-reduction targets — if it built fewer wind farms and more gas plants (given the economic advantages of gas over wind power over the next ten to fifteen years, in terms of up-front capital and finance requirements, particularly in an environment of lower gas prices increasingly delinked from those of oil).¹⁰⁷ However, whatever path the EU might ultimately decide to follow in this regard is less relevant than this change in attitude among traditional conventional gas exporters.

¹⁰⁷ See Tim Webb, “EU could meet carbon targets more cheaply with gas than renewables, say gas firms,” guardian.co.uk, February 13, 2011.

Second, the benefits of a new gas revolution will also impact consumers beyond the Atlantic Basin. China's growing need for energy imports, including natural gas, has helped shape recent Chinese foreign policy, underpinning its relationship with problematic energy producers such as Iran, Sudan, and Myanmar, and undermining related foreign policy objectives of the EU and United States in Central Asia, Africa, and Latin America. A less energy import-dependent China would likely no longer perceive its global interests so clearly opposed to those of the United States and the EU. The lubricant of cheap and increasingly mobile gas would help dissolve many flash-point issues that continue to complicate relations between China and the West: from the new Great Game in Central Asia to the Chinese stance on numerous border conflicts (many energy-related) with U.S. allies in Asia (in the South China Sea, for example); and from Chinese perceptions of a hostile intent behind U.S. military interventions and maneuvers around the globe to its view on the security of the sea lanes (particularly those delivering oil and LNG from the Persian Gulf — through the straits of Hormuz and Malacca — to China). The potential economic and security benefits for China would reverberate across the global energy economy, delivering secondary benefits to the Atlantic Basin in terms of a less frictional political and economic relationship with a rising, if still vulnerable, China — an economy that promises to be an increasingly critical foreign investor in the Atlantic Basin.

Should the nascent shale gas industry prove capable of effectively and sustainably overcoming the emerging local and environmental resistances analyzed earlier, shale gas might facilitate the construction of a welcomed, lower-carbon “gas bridge” to be built — literally across the southern Atlantic — to the next generation of modern and postmodern renewable energies and other low-carbon technologies.

2.4.2 The Midstream

The incipient global gas revolution also has important implications farther down the gas chain from the upstream. Over the past decade, the gas midstream has been transformed by the expansion of international trade in LNG. This liquid mode of natural gas transport has tended to diversify further any particular level of extra-Atlantic gas import dependence, and ultimately offers the

potential for the Atlantic Basin to become a significant net exporter of LNG to the world's other energy basins. Because LNG, a fungible liquid, can travel in tankers to and from ports around the world, it is relatively free of the risk of political, commercial, or technical disruptions perceived to be common to pipeline gas (although shipping practices and safety, along with the security of the sea lanes imply their own independent risks, equivalent to those of seaborne oil).¹⁰⁸

Furthermore, the expansion of the global LNG market has helped to transform the Atlantic Basin gas scene (even before considering the potential impacts of shale gas). LNG now comes from multiple sources internationally, but a number of these current LNG exporters are now located within the Atlantic Basin, and a number of others are potential LNG exporters. Nigeria and Trinidad and Tobago, the basin's leaders, each produce and export well over 20bcm of LNG every year, whereas Equatorial Guinea exports just over — and Norway, just under — 5bcm a year. On a different trajectory, Venezuela could potentially become a major exporter in the future. Meanwhile, Angola is expected to produce its first LNG in 2012.¹⁰⁹

Before the shale gas revolution exploded in the United States, LNG was expected to account for half of the international gas trade (currently around 30 percent, up from only 5 percent in the 1990s) by 2025.¹¹⁰ Although the absolute amount of LNG traded in the future is bound to continue to increase significantly, its future relative share of the global gas trade (including pipelined and seaborne liquefied — conventional and unconventional — gas) is likely to be somewhere between 30 percent and 50 percent, depending on how deep and broad the shale gas revolution ultimately turns out to be around the world. Although production and consumption of LNG is bound to grow, giving LNG a

¹⁰⁸ Indeed, the expansion of LNG implies a shifting of geopolitical risks, from pipeline politics to heightened strategic concern over the security and protection of the world's sea lanes. This shift would be reinforced in any future gas-dominated Atlantic Basin, as most of the critical energy-bearing sea lanes are either intrabasin or extrabasin, connecting the Atlantic to the Indian Ocean and Pacific energy basins. Nevertheless, a more deeply integrated Atlantic Basin energy system might generate strategic collaboration within the basin that might more effectively contain such risks.

¹⁰⁹ The "broad" Atlantic Basin would include Algeria (the world's second-largest LNG producer, after Indonesia), Libya, and Egypt, also significant LNG producers and exporters.

¹¹⁰ Amy Myers Jaffe, "Shale Gas Will Rock the World," *Wall Street Journal*, May 10, 2010.

promising future, the extremely high uncertainty surrounding the global potential for shale gas also complicates the dynamics between shale gas and LNG as well as any future projections of the ultimate role of LNG into the future.

Nevertheless, of the 297bcm of internationally traded LNG in 2010 — itself some 30 percent of all international gas movements, with pipelined gas accounting for some 677bcm — nearly 25 percent (or 69bcm) is broadly defined as “pure” intra-Atlantic Basin LNG trade.¹¹¹ Interbasin Atlantic–Pacific LNG trade comes to 13.23bcm, or 4.5 percent, of the total LNG trade, of which only 0.87bcm (or 0.2 percent of total LNG trade) represent imports into the Atlantic Basin. The interbasin Atlantic–Indian LNG trade, on the other hand, totals 34.43 bcm, or nearly 12 percent of global LNG trade, of which 33.05bcm (11.1 percent) are LNG imports into the Atlantic Basin.

As of 2010, the Atlantic Basin as a whole was still a net importer of LNG, importing in net terms some 19.31bcm (or 682bcf) of LNG.¹¹² But the Pacific Basin is still more dependent on the Indian Ocean Basin than is the Atlantic, which over the long run is most likely to become even more self-sufficient in LNG. Total Pacific–Indian Ocean interbasin LNG trade comes to 47.15bcm, of which 46.82bcm is imported from the Indian Ocean Basin (including the Persian Gulf but excluding Russia) into the Pacific Ocean basin (with net imports totaling 46.5bcm). Meanwhile, the Atlantic has only 31.67bcm of net imports from the Indian Ocean, a third lower than the Pacific Basin, which consumes far less gas than does the Atlantic Basin, and has much lower gas reserves.

Therefore, the Atlantic Basin’s involvement in the total global LNG trade (including “pure” intra-Atlantic Basin trade, plus Atlantic Basin interbasin trade with the Indian and Pacific Ocean basins) comes to more than 40 percent of global LNG. It should also be remembered that the Atlantic Basin was a latecomer to the LNG scene. Although “broad Atlantic” producers such as Algeria were the initial pioneers in LNG, the first center of the LNG market was in Asia, where East Asian demand provided the first impetus for the global market. Yet in the last 20 years, the Atlantic Basin LNG market has developed

¹¹¹ LNG figures come from BP’s *Statistical Review of World Energy*, 2011.

¹¹² Arrived at by taking the 12.36bcm of net Atlantic exports to Pacific, and subtracting from it the 31.67bcm of net Atlantic imports from Indian Ocean Basin.

rapidly, lending its 25 percent weight in the global LNG market (when measured in terms of pure intrabasin trade; 40 percent when including the Atlantic's interbasin trade) even more significance, given its recent dynamism and momentum.¹¹³

However, the shale gas revolution in the United States has already begun to shift the center of gravity of the global LNG market back eastward, as Qatari exports that once were planned for the U.S. market now head to Europe, and as other LNG exporters (within and beyond the Atlantic Basin) begin to shift their export focus from the Atlantic Basin to the Indian Ocean Basin and the Pacific. Although such a trend might reduce the weight of the “pure” intra-Atlantic Basin trade within the global total, as demand for LNG shifts eastward, the Atlantic Basin LNG system will become an even larger net exporter, deepening its autonomy within the global LNG market. The overall effect of such trends will be to strengthen the natural gas system (pipelined gas plus LNG) within the Atlantic Basin, reducing the overall net gas dependence of the basin — now around 6 percent (see section 2.2 on Atlantic Basin Natural Gas) — even further.

2.4.3 *The Downstream*

The Atlantic's hydrocarbon downstream is now in a period of uncertain flux. What was once simply a collection of traditional petroleum refineries scattered around the basin (if concentrated in the North) has now become a diverse system of different energy forms and modes of transport and delivery, pushed on not only by the emerging market economic expansions of the southern Atlantic, but also by the global driver of the low-carbon economy. LNG, heavier oils (requiring specific new types of hydrocracking

¹¹³ “Two distinct LNG trade regions have developed over the past few decades: the Atlantic and the Pacific regions. Until Qatar, and to a lesser extent, Oman, began to export LNG to both regions in the mid-1990s, the two regions were largely separate, with unique suppliers, pricing arrangements, project structures, and terms. There were occasional spot sales with suppliers from the Pacific region selling to the Atlantic region customers. However, long-term contracts between the regions began with Qatar and Oman selling to Europe and North America. Future plants in Australia, Indonesia (potentially exporting to western North America), and Yemen are all looking at exporting to both the Atlantic and Pacific markets, further blurring the distinction between the regions. ... The regions have begun to converge as some suppliers contract with buyers in both regions, and consumers from the two regions demand similar terms from their suppliers.” In this way, LNG has the potential to ultimately globalize the traditional regional gas (both pipeline and LNG) markets — although shale gas and GTL might modify the trajectory of global LNG. See Vivek Chandra, <http://www.natgas.info/html/gastrade.html>.

refineries), biofuels, gas-to-liquids, and even compressed natural gas (CNG) have complicated the downstream energy link to the transportation sector. The southward shift in the center of gravity within the Atlantic has also lent this trend even more dynamism and interesting potential.

Although biofuels have captured the lion's share of the global public's attention, another quiet development in the downstream realm also suggests interesting potential. Gas-to-liquids (GTL) technology has been developed in South Africa and the United States, and it has been deployed in South Africa's Mossel Bay, Qatar, Nigeria, and Southeast Asia. GTL offers the possibility of converting relatively abundant and clean natural gas directly into "synthetic" liquid gasoline (methanol) or diesel equivalent. Such technology allows natural gas to break into the transportation sector, currently 97 percent dependent on oil, particularly where large-scale biofuels production makes less sense in the presence of large reserves of gas. GTL technology could be the *coup de grace* on the shale-driven gas revolution. That the world's fourth-largest shale gas reserve holder (Argentina) and the world's pioneer in GTL technology and production (South Africa) should face each other across the southern Atlantic only reveals further the potential for a dynamic Atlantic Basin energy system to emerge.

GTL has long been considered to be the holy grail of gas technology.¹¹⁴ Like nuclear fusion, another "grail" technology, it has nevertheless always seemed too remote as a mass possibility to be of much use. Because more than 40 percent of the gas is consumed in the GTL conversion process, until recently it was deemed economically feasible only for marginal uses: to take advantage of stranded gas,¹¹⁵ to monetize the benefits of reducing the incidence of "flaring" (Angola would be a prime Atlantic Basin beneficiary of Sasol GTL technology to monetize its hitherto flared gas),¹¹⁶ or for novel

¹¹⁴ See Vivek Chandra, "Gas-to-liquids" at <http://www.natgas.info/html/gastrade.html>.

¹¹⁵ Nearly half (3,000tcf) of the world's proven conventional gas reserves of 6,100tcf are considered to be remote or stranded, and therefore not easily or economically accessible to markets by either pipeline or LNG.

¹¹⁶ The World Bank estimates that more than 150bcm of natural gas is flared or vented annually, an amount worth approximately \$30.6 billion, equivalent to 25 percent of the United States' gas consumption or 30 percent of the European Union's gas consumption per year. See World Bank, "GGFR Partners Unlock Value of Wasted Gas," World Bank, December 14, 2009.

uses on FPSOs to convert offshore gas directly to liquid fuels.¹¹⁷ Furthermore, after some initial successes (ExxonMobil in New Zealand, Shell in Malaysia, and Sasol and PetroSA in South Africa), earlier cycles of synfuel enthusiasm flared out in significant cost overruns and long delays on key next-generation GTL projects in Qatar (Sasol's Oryx and Shell's Pearl) and Nigeria (Sasol's Escravos).

Like Canadian oil sands and Orinoco super-heavy oil, GTL only really becomes feasible within a high-oil-price environment. However, the shale gas revolution and the delinking of oil and gas prices offer even more promise for GTL in the future, given that oil prices seem to be permanently embedded above \$60/bbl. A number of years ago, Chemlink Consultants from Australia concluded that GTL would be economically viable with petroleum prices above \$25/bbl.¹¹⁸ Today, oil prices are at \$85/bbl in the United States and around \$100/bbl in Europe. Should shale solidify and the delinking process become complete, the opportunities for GTL to expand within the Atlantic Basin downstream will be notable — particularly with its key competitor, petroleum, increasingly constrained by the prices of carbon and crude oil.

Furthermore, the pessimism generated by the long delays and large cost overruns (at Escravos in Nigeria, and Oryx and Pearl in Qatar) had its roots primarily in the various input bottlenecks blocking the route all the way up the supply chain during the great boom in demand before the September 2008 crash, a period during which the prices of materials, manpower, and knowledge were rising considerably. In a world of excess capacity, however, such price pressures have been worked out of the chain. Indeed, a number of critical factors — including the jump-step in average oil prices over the past decade, the shale gas revolution in the United States, and the subsequent fall in gas prices, along with an increasingly tight carbon constraint (in reality, if not yet in price) — have recently coalesced to reshape the economic equation of GTL's potential.

¹¹⁷ Even Petrobras has ordered some units for experimental use in the pre-salt offshore.

¹¹⁸ "Under conditions that may be considered reasonable, a GTL project with present technology could be cost competitive with crude oil prices around \$25 per barrel but any shifts in the key cost factors could significantly raise the competitive price. This uncertainty about world oil prices, rather than the technology has served to limit GTL investment." See Chemlink Consultants (Australia), at <http://www.chemlink.com.au/cv.htm>.

The Atlantic Basin claims the key clutch of global leaders in GTL technology: Sasol of South Africa, ExxonMobil of the United States, and Royal Dutch Shell of Europe. Sasol has been an early pioneer in the production of synthetic diesel fuel (diesel accounts for nearly 50 percent of the global transportation fuel market, and this dependence is even higher in developing countries), whereas ExxonMobil has pioneered the production of methanol, a synthetic replacement for gasoline. Currently these companies are involved in GTL production or projects under construction in South Africa (Sasol), Malaysia (Shell), New Zealand (ExxonMobil), Qatar (Shell and Sasol), and Nigeria (Sasol), and there are now plans to begin GTL plants in Canada (Sasol), Uzbekistan (Sasol), and Louisiana (Sasol).

Furthermore, production at Shell's landmark Pearl GTL plant in Qatar has finally begun. With a final capital cost of \$19 billion, Pearl has been one of the most expensive energy projects ever. When it was initially proposed in 2002, Shell had estimated total capital costs of \$4.5 billion. By the time of the final investment decision, capital costs had risen to \$14-\$18 billion. Nevertheless, by 2012, Pearl will be running at full capacity, producing 140,000bd of premium synthetic fuels (diesel, naphtha, and kerosene) and 120,000bd of upstream liquids (condensate and liquefied petroleum gas, or LPG). At \$100/bbl, revenues are expected to be \$9 billion a year, with payback in just over two years. At \$50/bbl, payback would come in a little more than four years.¹¹⁹

Sasol's Oryx, also in Qatar, has been more of a technological disappointment (it took three years to reach the same 34,000bd capacity as the PetroSA plant in Mossel Bay), but in the end it has turned out to be profitable, principally because of its very low initial capital cost (\$1 billion). But a similarly sized GTL plant at Escravos in Nigeria is expected to cost \$6 billion and is already years behind schedule. In the end, timing (with respect to the economic and petroleum cycles) and location (with respect to political risk and economic infrastructure and synergies) turn out to be critical variables affecting costs and therefore the long-term profitability of GTL.¹²⁰

¹¹⁹ See Alex Forbes, "Pearl promises a new dawn for GTL," *Petroleum Economist*, March 2011, p. 12.

¹²⁰ *Ibid.*

It is precisely these critical variables of timing and location that point to a potential rollout of GTL technology in the Southern Cone, beginning in Argentina and extending into Brazil. A series of Sasol GTL plants along the Argentine and Brazilian coasts (and in Argentina's case, also in the interior gas basins) could provide synthetic gasoline and diesel substitutes to complement the region's growing biofuels production. Under this scenario, Atlantic South America could become the first major region to become virtually petroleum-free, providing significant impetus for North America and Europe to follow suit.

Granted, much depends on the shale gas revolution successfully extending itself to at least Argentina, if not also South Africa. Much is at stake for the latter, and particularly for its major companies, Sasol and PetroSA. The potential for GTL in Latin America provides one level of support for these companies; but limiting them on the other side, especially financially, is a lack of domestic (and even foreign-controlled) gas supplies. The potential shale gas of the Karoo Basin looms especially large in this context (see the section on South Africa).

In addition, the carbon constraint is becoming increasingly restrictive (if not yet sufficiently so). This is precisely where the most uncertainty is imbedded into the future of GTL. GTL synthetic fuels have uncontestable environmental advantages over conventional gasoline and diesel with respect to a wide range of pollutants (including carbon monoxide, sulfur oxides, nitrogen oxide, and particulate matter).¹²¹ Nevertheless, there is still a relatively high amount of uncertainty regarding the potential advantage of GTL compared to conventional fuels in the area of carbon dioxide emissions. Here the uncertainty is built into various parts of the full life cycle of the fuel.

First, there is still a controversy regarding the ultimate greenhouse gas effects of shale gas, given the potential for fugitive emissions of methane. Second, there is also some doubt around the supposed advantage of GTL versus petroleum-based fuels in the downstream in the emission of CO₂ (some argue that the GTL process could actually produce slightly more CO₂ than does traditional

¹²¹ This additional pollution advantage of GTL synfuels is becoming even more acute, given increasingly stringent pollution control standards in the EU.

refining).¹²² Carbon capture and sequestration (CCS) could help resolve this uncertainty, but it is likely to raise costs significantly. Emissions uncertainty could turn out to be a defining barrier to GTL expansion in the southern Atlantic over the short-term future.

Finally, there is the issue of GTL's potential impact on LNG developments and, vice versa, the impacts of LNG developments on GTL potential, particularly in the southern Atlantic. These incipient and intersecting gas technology vectors across the Atlantic are not necessarily in competition with each other (or mutually exclusive in any other way), but they do introduce further uncertainty into the gas realm of a nascent Atlantic Basin energy system.

Liquefied natural gas (LNG) is cooled and compressed into its liquid form at liquefaction export plants. Traveling in this liquid form by specialized tanker is more economical at long distances (more than 2,500 to 3,000 miles) than by pipeline (which themselves are becoming more difficult to build for economic, environmental, and political reasons). At regasification import plants, the LNG returns to a gaseous state and enters a country's internal gas infrastructure, typically burned in the end in gas-fired electrical generation plants, or used in the industrial and household sectors. Currently, no LNG is converted into liquid fuels. Furthermore, gas still has a large margin within the current energy matrix to take over from coal in electricity generation. Given that GTL technology converts gas directly into synthetic gasoline and diesel substitutes, there is no direct market competition between these two gas modes/technologies. GTL-produced synthetic fuels will not necessarily even directly compete with biofuels, at least not until they have both significantly eaten into petroleum's share of the transportation energy mix. Potential competition (for markets and for network externalities stemming from dominance over the infrastructural mode of the energy system) would develop, and only even theoretically, decades in the future.

At the broad level of market share (where there is plenty to go around given the combined projected displacements of oil and coal from the primary energy mix over the long run), there is no

¹²² "GTL fuel lifecycle greenhouse gas emissions are approximately 25 percent higher than conventional oil." See Chemlink Consultants (Australia), at <http://www.chemlink.com.au/cv.htm>.

competitive conflict that might distort the respective development of LNG and GTL within the Atlantic Basin. Where gas deposits are large enough, both technologies (with their different predominant end-uses: electricity versus transportation) could be deployed side by side, generating cost gains from synergies in labor and infrastructure, accelerating the development of both. Some companies even claim that GTL synfuels based on LNG feedstock can achieve lower operating costs or allow synfuels production at a much smaller scale than would otherwise be necessary to remain competitive.¹²³

Nevertheless, at the more micro-level of the investment decision, competition between LNG projects (with gas destined for the electricity and industrial sectors) and GTL projects (with gas destined for the transportation sector) will likely present the classic crossroads investment uncertainty given the path-dependent nature of decisions on, and outcomes of, capital-intensive projects with such high up-front costs. Still, even with such investment uncertainty clouding the middle- and long-run horizons of LNG and GTL, in the short run GTL would seem to be more attractive as a strategy, particularly given the higher profit margins to be reaped in the transportation sector and the current gas glut and production overhang in the global LNG market.

One option for dealing with the remaining uncertainty would be to encourage double joint ventures (perhaps with multiple partners) to produce both LNG and GTL synfuels on large gas projects around the basin. This would help stimulate an orderly sharing of both the expanding electricity and transportation fuels markets. Another would be to identify the countries in the Atlantic Basin that might be better suited, in relative terms, to produce LNG, along with those that might be better advised to concentrate on GTL. Argentina, for example, might be better suited to exploit GTL along with its potential shale gas, whereas Nigeria might be advised to concentrate on expanding the LNG production that it already has up and running, rather than to focus on the GTL realm, where its first experience with Sasol's Escravos plant has been marred by significant delays and cost overruns.

¹²³ For example, the company, Syntroleum. See Chemlink Consultants (Australia), at <http://www.chemlink.com.au/cv.htm>.

Five years ago, with gas prices rising in tandem with spiraling oil prices, and with the sector's flagship projects around the world mired in cost overruns and delays, serious doubts hung over the future of GTL, still a marginalized segment of the gas sector. At the time, the EIA forecast an increase of only 200,000bd of synfuels production by 2030 in its "high scenario" for GTL.¹²⁴ Today, however, in the middle of a global gas revolution, various market, environmental, and technological forces have combined to brighten the outlook for GTL considerably. The delinking of gas from oil prices, which appear set to remain relatively high, if volatile, in historical terms, will significantly lower the price of GTL's feedstock compared with that of its competitors, conventional petroleum-based gasoline and diesel. Meanwhile, the evolution of GTL technology is also making the option more flexible and capable of taking advantage of a wider range of possibilities, increasing its economic attractiveness. Finally, if the shale gas industry can demonstrate an effective control over fugitive emissions of methane, and assuming that CO₂ emissions are eventually priced correctly in relation to their true economic costs, GTL synfuels will have an even more promising future.¹²⁵

The gas revolution — girded by the tightening carbon constraint and driven by shale in the upstream, LNG in the midstream, and GTL in the downstream — is gathering steam in the northern Atlantic Basin, but it has the potential to soon explode in the southern Atlantic. Although investment from the northern Atlantic will remain critical, the major gas producers and consumers of the southern Atlantic have the potential to catalyze the formation of an Atlantic Basin gas system, which could further integrate the basin all along the gas supply chain.

Gas-to-liquids fuels may have a dynamic future that could herald the end of petroleum, if not fossil fuels. However, to date the only serious displacement of petroleum from the transportation fuel

¹²⁴ See John Venezia and Jeff Logan, "Weighing U.S. Energy Options: The WRI Bubble Chart," World Resources Institute, July 2007. Synfuel production at Shell's Pearl GTL plant in Qatar alone in 2012 will surpass EIA's former 2030 GTL production projection.

¹²⁵ Indeed, the MIT gas study concludes that "if this trend (the delinking of gas from oil prices) is robust, use of natural gas in transportation, either through direct use or following conversion to a liquid fuel, could in time increase appreciably." See "The Future of Natural Gas: An Interdisciplinary MIT Study," *op. cit.*

mix has occurred as a result of biofuels expansion, particularly that of ethanol.

Although there are a number of biofuels producers in the Atlantic Basin — the United States (the world's largest producer of ethanol), Spain, and Germany (a leader in biodiesel) — Brazil remains the biofuels leader of the world, as well as the key to the sector's future. Brazil is currently the second-largest producer of ethanol in the world behind the United States. In 2009, it produced 450,000bd of ethanol, down from 467,000 in 2008. Despite this decline (analyzed more below), the Brazilian Sugarcane Industry Association (UNICA) expects production to rise again following a very successful 2010–2011 harvest.

Although Brazil has long been the world's leading ethanol exporter, most additional future production will be used to meet increasing domestic demand. As such, the United States has already overtaken Brazil in the global export of ethanol, at least temporarily. All gasoline in Brazil contains ethanol, with blending levels between 20 percent and 25 percent. Furthermore, more than half of all cars in Brazil are of the flex-fuel variety, meaning that they can run on 100 percent ethanol or any ethanol-gasoline blend. Approximately 2.5 percent of Brazil's arable land is dedicated to the production of sugarcane. About 40 percent of this (or 1 percent of total arable land) is now dedicated to the production of sugar, and some 60 percent (or 1.5 percent of arable land) is dedicated to the production of sugarcane for ethanol.¹²⁶

Brazil has progressed through a number of phases in its biofuels expansion. The first (1975–1992) was the *Pro-alcohol phase*, during which production was encouraged by the state through subsidies and price controls. Some believe that the left wing of the ruling PT government would like to change ethanol and oil policy so as to return to a similar situation in which the state would exercise a much deeper control over these key strategic sectors.

The second phase (from 2000 to recent years) was a cycle of expansion stimulated primarily by the Brazilian automobile industry, which has introduced a large number of flex-fuel vehicles into the car fleet. During these years, sugarcane production

¹²⁶ EIA, op. cit.

increased by 10.3 percent annually, driven by strong sales of flex-fuel vehicles. With some 20 new plants opened each year since 2005, this period was characterized by an abundance of cheap capital, new investors with limited experience in the sugarcane industry, and traditional businesses with limited access to modern financial tools. With the prevailing low sugar prices of the time, new investments were stimulated by the prospect of healthy profit margins for ethanol in Brazil and abroad.¹²⁷

However, the 2008 global crisis weighed heavily upon precisely the Brazilian biofuels companies that invested the most. The sector slipped into precipitous crisis as a result of a perfect storm of multiple colliding headwinds. One-third of Brazil's industry ran into difficulties and went through significant financial and corporate restructuring. The central underlying factors behind the crisis included:

- the most recent drought on the sugarcane harvest, raising international sugar prices — which also undermined Brazil's domestic supply of ethanol and raised the prices of biofuels as well;
- a decline in investments related to the 2008–09 global financial crisis; and
- other operational limitations arising from a wave of corporate consolidations still taking place in the sector.

In general, the short-term horizon for biofuels has improved tremendously over the last year. Existing companies have once again achieved solid growth, while traditional agribusiness, oil, and chemical groups have begun to enter the sugarcane industry in full force. However, investments during the years since 2008 have been targeted at the purchase of troubled companies, whereas production expanded only 3 percent annually since the global financial crisis.¹²⁸ Since then, the ethanol industry has failed to keep pace with its previous development, given the difficulties, mentioned earlier, that the sector has recently faced.

¹²⁷ Marco Jank, "Ethanol — a new growth cycle," *Correio Braziliense*, April 27, 2011.

¹²⁸ *Ibid.*

Many have speculated about whether or not we are on the brink of a new cycle of investment in the Brazilian ethanol sector, after having experienced a number of production constraints in recent years that now appear to be in the process of resolution. However, most entrepreneurs are not yet convinced, given a range of other uncertainties that continue to cloud the short-term investment horizon for the Brazilian sector. These include:

- uncertainty as to the future of regulation, not just in the ethanol sector, but also in the petroleum products sector against which ethanol must compete in Brazil's domestic market (and which is characterized by a Petrobras monopoly and state price controls that keep gasoline prices low);¹²⁹
- inflationary pressures creeping back into the Brazilian economy;
- a strong real; and
- lack of certainty with respect to the future of the U.S. tariff on imports of Brazilian ethanol (54 cents per gallon) and U.S. transportation fuel demand in general, particularly given the recent reduction in gasoline demand, sluggish growth in the U.S. economy and the potential for the penetration of electric vehicles into the U.S. market.¹³⁰

Regulatory and market intrusions in the Brazilian internal gasoline market continue to force distortions upon the domestic ethanol market. However, one measure long demanded by the ethanol industry — changing ethanol's legal classification from an agricultural commodity to a fuel — has recently been taken by the government. As a fuel, ethanol is now regulated by the National

¹²⁹ Prices at the pump are approximately 30 percent lower in Brazil than the international average.

¹³⁰ Brazil produces approximately 27 billion liters of ethanol, whereas the United States produces some 40 billion liters. Nevertheless, the current U.S. legislative mandate calls for the production of 140 billion liters in 2022, nearly 60 percent (or 80 billion liters) of which is mandated to come from advanced biofuel technology (i.e., cellulosic biomass). The Brazilian industry does not enjoy the advantages of a similar mandate. Brazil exports only 10 percent of its total ethanol production, while at the same time it exports between 60 percent and 70 percent of its total sugar production. Some argue that without U.S. tariff barriers, Brazil would export up to 40 percent of its total biofuels production. Interview with Marcos Sawaya Jank, *op. cit.* However, recently two proposed legislative liberalizations of the U.S. ethanol industry, motivated in part by U.S. domestic budgetary constraints, may point to the potential for U.S. subsidies to corn-based ethanol and import tariffs on Brazilian ethanol to be progressively reduced and eventually eliminated.

Petroleum Agency (the ANP, as are oil and gas), creating more possibility for the competitive distortions between oil derivatives and ethanol to be progressively ironed out, as well as for greater predictability in supply-demand relations. Nevertheless, at least some weakness in ethanol supply is expected in 2012, even after a reduction in the percentage of ethanol blended into the domestic fuel supply — from the current 25 percent to 18 percent, as recently proposed by President Rousseff — has been factored into the equation.

A third phase could now begin to unfold in the evolution of Brazilian biofuels, however, characterized by a significant expansion of sugarcane-based bagasse-fired electricity, along with the creation of a range of new low-carbon sugarcane-derivative products.¹³¹ This latter development would involve moving the Brazilian ethanol sector beyond the production of the mere feedstock inputs (sucrose and cellulose) to higher-value-added products including not just ethanol but also sugarcane-based chemical products, biokerosene, diesel from sugarcane, etc. Currently, however, the bulk of innovation in this regard is still taking place in the United States. Brazil should use more of its oil profits to invest in biofuels research and development (R & D).

Indeed, the post-crisis scenario is dramatically different: More than 70 percent of the cane industry is now comprised of groups with sizeable assets, capital structure and governance, operational performance, and access to high-quality capital. These are groups ready to invest. The problem is that market catalysts today are very different from those observed in 2005. Over the past six years, the cost of ethanol production has increased more than 40 percent, damaging ethanol's competitiveness with respect to gasoline, which has seen virtually no price fluctuation at the pump in Brazil since 2005. Besides a significant reduction in margins, which currently do not justify heavy new investments, investors also have sensed a lack of criteria in Brazil's establishment of the price of gasoline, the direct competitor of ethanol at the pumps.

Land availability, technology, and capable and motivated employees are not factors that currently affect or hinder the efficient growth and expansion of the ethanol industry. Difficulties in management,

¹³¹ Bagasse is the sugarcane pulp fiber remaining after the extraction of the sweet sap.

governance, and capital also have been overcome. What is still needed is an adequate strategy to address structural factors that have reduced the competitiveness of ethanol. These are measures that require major efforts from both the public and private sectors: harmonization of federal and state taxes with reduced tariffs, strong incentives for bioelectricity, improved logistics and storage, a commitment to ensure the supply of the biofuel, increased productivity, cost reductions, and improvements in flex-fuel engine efficiency.

Despite everything, the sector is once again showing signs of recovery and expansion. The Brazilian Development Bank, BNDES, plans to extend 30 billion to 35 billion reais (\$18.9 billion to \$22.1 billion) in loans to the sugarcane and ethanol sectors in a bid to facilitate expanded production through 2014.¹³² Meanwhile, the Brazilian sugar and ethanol company Cosan reported an increase in sales of ethanol, gasoline, and lubricants of 64 percent (to 487 million reais) in the quarter ending March 31, 2011, and plans to invest between 2 billion and 2.3 billion reais in 2012.¹³³ Additional investments in expanded ethanol supply have been announced by BP, Louis Dreyfus Commodities (LDC), and the Brazilian companies Petrobras and Brasken.

Such expressed commitments have created a newly heightened expectation for growth, not only in ethanol production but also in the market for electric cogeneration from bagasse. Furthermore, Petrobras has recently entered into a joint venture (through its subsidiary Martinho and Petrobras Biocombustível) with the Brazilian bioenergy firm Nova Fronteira to begin production of sorghum-based ethanol as a complement to sugarcane-based ethanol (to be grown between sugarcane harvests).¹³⁴ Developments such as these will help the biofuels sector gain more relatively autonomy from both the harvest cycle and the oil price cycle, allowing it to expand more rapidly in the future.¹³⁵

¹³² “Brazil to Invest As Much As \$22 Bn to Boost Ethanol Production,” *Latin America Energy Advisor*, Inter-American Dialogue, June 6–10, 2011.

¹³³ Last year Cosan also completed a \$12 billion joint venture with Royal Dutch Shell, the world’s largest sugarcane processor. “Cosan Profits Rise 64 Percent on High Fuel Demand,” *Latin America Energy Adviser*, Inter-American Dialogue, June 6–10, 2011.

¹³⁴ Business Latin America, Economist Intelligence Unit, May 2, 2011.

¹³⁵ This will also dovetail with new techniques to intensify agriculture in order to mitigate GHGs released by the sector.

In the global transportation market, bio-jet fuel represents an enormous potential for the Brazilian biofuels industry. The development and production of biokerosene would be the only potential way to reduce CO₂ emissions in the aviation sector, given that there is no conceivable electrification process for air travel. The global industry is not far from being able to produce biokerosene from cultivated plants. Furthermore, in the wake of the recent UN Agreement on Bioelectricity, there is also much potential for the production of bioelectricity in Brazil from bagasse. A new, positive outlook among bagasse power entrepreneurs could help stimulate further growth in bioelectricity. UNICA is now considering potential electricity exports in 2020 of some 14GW annually.¹³⁶

2.5 Electricity Generation and Low-carbon Energy in the Atlantic Basin

2.5.1 Electricity and Renewables

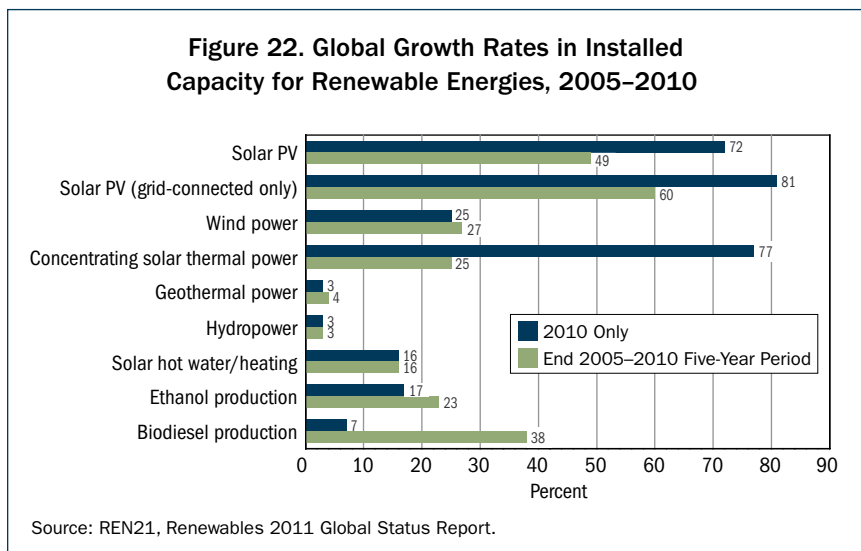
The world currently has some 5,000GW of installed electrical generation capacity, a figure that is expected to double over the next 30 to 35 years. Most of this new capacity is expected to be added in Asia, above all, but also within the countries of the Atlantic Basin, particularly in the South. The fossil fuels — coal (41 percent), oil (5 percent), and gas (21 percent) — still account for more than 70 percent of the world's electricity generation mix, with nuclear energy contributing another 13 percent. Hydropower accounts for some 16 percent of world electricity generation, and modern renewables contribute 3 percent.

About 25 percent of global installed capacity is now renewable energy generation. Much of this is hydropower (around 20 percent, of which most is large hydro), and nearly 4 percent of total world installed capacity is modern renewables (mainly wind, solar, and geothermal). Nevertheless, renewable energy accounted for around 50 percent of the estimated 194GW of new electrical capacity added globally in 2010.¹³⁷ Global wind power capacity increased

¹³⁶ Interview with Marcos Sawaya Jank, President and CEO of UNICA, the Brazilian Sugarcane Industry Association, São Paulo, June 8, 2011.

¹³⁷ REN21, *Renewables 2011 Global Status Report*, Renewable Energy Policy Network for the 21st Century, 2011.

25 percent in 2010, rising by nearly 40GW to a total of 200GW.¹³⁸ Solar power capacity grew by more than 70 percent, with other forms of renewables capacity also growing strongly, albeit at much lower rates (see Figure 22). For the past 15 years, renewable energy capacity additions have outpaced nuclear power, another large potential source of low-carbon electricity.¹³⁹



In the United States, renewable energy accounted for about 10.9 percent of domestic primary energy production (compared with nuclear’s 11.3 percent), an increase of 5.6 percent relative to 2009. Germany, another leader in renewable energies in the northern Atlantic, met 11 percent of its total final energy consumption with renewable sources, which also accounted for 16.8 percent of electricity consumption, 9.8 percent of heat production (mostly from biomass), and 5.8 percent of transport fuel consumption (mainly biodiesel). Wind power accounted for nearly 36 percent of renewable generation, followed by biomass, hydropower, and solar photovoltaics (PV). Several other European countries met

¹³⁸ David Appleyard, “Despite Financial Crisis, Renewables Surged Forward in 2010,” *Renewable Energy World International*, August 30, 2011.

¹³⁹ In the United States, the share of renewable energies in new capacity additions rose from 2 percent in 2004 to 55 percent in 2009, with no new nuclear capacity coming on line. In 2010, for the first time, worldwide cumulative installed capacity of wind turbines (193GW), biomass and waste-to-energy plants (65GW), and solar power (43GW) reached 381GW, outpacing the installed nuclear capacity of 375GW prior to the Fukushima disaster. See Mycle Schneider, et al., “Nuclear Power in a Post-Fukushima World: 25 Years after the Chernobyl Accident,” *World Nuclear Energy Industry Status Report 2010–11*, Worldwatch Institute, Washington, DC, April 2011.

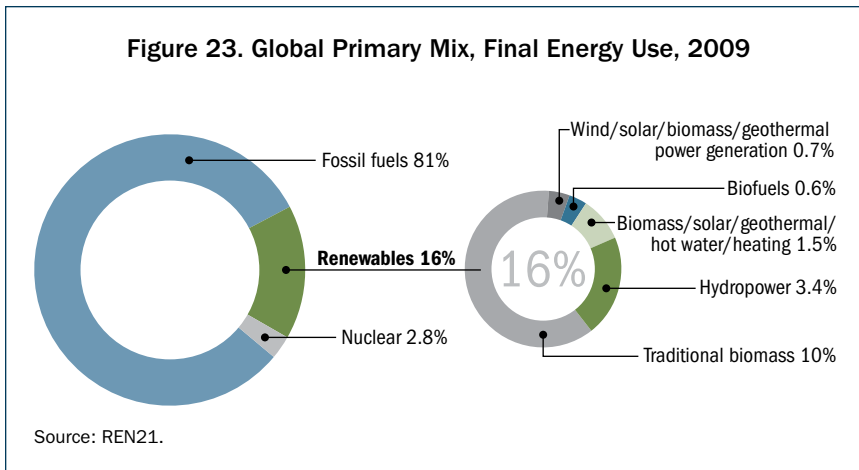
higher shares of their electricity demand with wind power in 2010, including Denmark (22 percent), Portugal (21 percent), Spain (15.4 percent), and Ireland (10.1 percent). However, since the global financial crisis, China has been the biggest national player in renewable energies, adding some 30GW of grid-connected renewable capacity (to reach 263GW), an increase of 12 percent over 2009. In 2010 renewables accounted for 26 percent of China's total installed electrical capacity, 18 percent of generation, and more than 9 percent of its final energy consumption.¹⁴⁰

These recent additions to the installed capacity of renewable energy have allowed renewables to penetrate deeper into the global energy mix. Global energy consumption rebounded in 2010 after an overall downturn in 2009. Renewable energy, which experienced no downturn in 2009, continued to grow strongly in all end-use sectors — power, heat, and transport — and supplied an estimated 16 percent of global final-energy consumption in 2010.¹⁴¹ However, stripping out traditional biomass (firewood, dung, etc.), which accounts for 10 percent of the world's primary energy use, “modern renewable energy” (wind, solar, biomass electricity generation, and geothermal) accounts for just under 3 percent and hydropower provides for 3.4 percent of total global energy use (see Figure 23).¹⁴² Nevertheless, it is estimated that renewable energy will contribute between 25 percent and 58 percent of the world's total energy supply by 2030, under a scenario of dramatic scaling-up of renewable energy and energy efficiency, capable of avoiding the

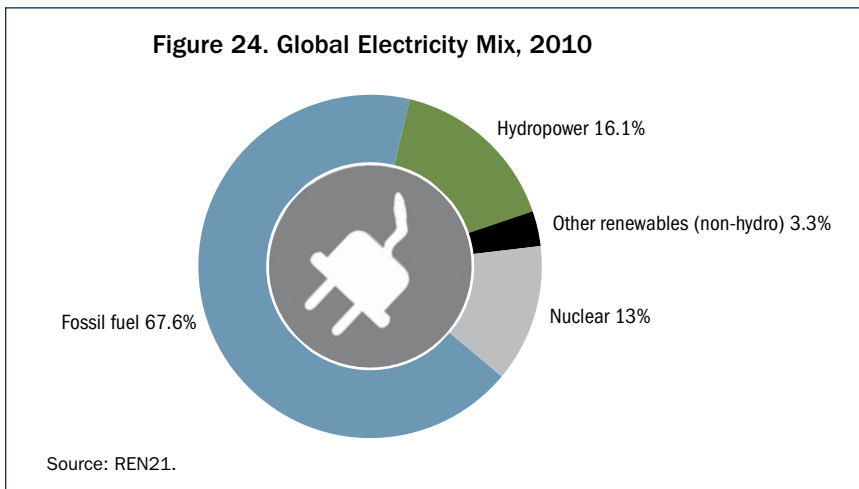
¹⁴⁰ REN21, *op. cit.*

¹⁴¹ *Ibid.*

¹⁴² There can be some confusion over the terms “renewable” and “modern renewables,” particularly with respect to hydropower. Some definitions of renewable energy include hydro; others do not. Some include, however, small-scale hydropower under 50MW. Most uses of the term “modern renewable energy” include small-scale hydro along with solar, wind, geothermal, wind, etc. In this study, the term “modern renewable energy” tends to include: solar, wind, geothermal, small-scale hydro, and modern uses of biomass to produce gas or electricity. However, we diverge when certain international references categorize differently (as in the case of the REN21 document, which includes everything — even traditional biomass and large hydro — in its classification of “renewable energy” within its presentation of the global primary energy mix, but which excludes hydro, large and small, from its categorization of “renewable energy” in the global electricity mix. Another confusion often surrounds the categorization of “biomass.” Many uses of the term “renewable energy” include all biomass, even “traditional biomass” (wood, charcoal, dung, etc.), but most uses of “modern renewable energy” would exclude the latter. However, when looking at the electricity mix, traditional biofuels disappear from the calculation.



worst aspects of climate change and eliminating energy poverty.¹⁴³ In the somewhat differently configured global electricity mix, renewables (more broadly defined to include all hydropower) now account for nearly 20 percent of world electricity generation (16 percent hydropower, both large and small, and 3.3 percent other “modern renewables”) (See Figure 24).



2.5.2 Continuing Boom in Renewable Energy Investment

Underlying these remarkably rapid growth rates over the last five years in renewable energy deployment (in terms of installed capacity and increasing share of the primary energy and electricity mixes) has been the unprecedented boom in global investment

¹⁴³ The lower estimate comes from the IEA (International Energy Outlook, 2010), and the higher estimate comes from Ecofys (see Ecofys and WWF, The Energy Report 2011).

in renewable energy, which increased 32 percent in 2010 to \$211 billion (nearly five and a half times the figure achieved as recently as 2004). Although the political fallout and economic distortions of the 2008 financial crisis and ensuing recession have cast a passing cloud over the world's first true blossoming of renewable energy investment, global renewables investment surged again rapidly in 2010 (growing by \$51 billion to \$211 billion) after having remained flat in 2009 (rising only \$1 billion from 2008's \$159 billion).¹⁴⁴ Furthermore, during the first quarter of 2011, global wind and solar investments came to more than \$41 billion, an amount putting wind plus solar investment on a pace to reach \$160 billion, implying an increase of approximately 30 percent over the 2010 total.¹⁴⁵

However, although the crisis temporarily tempered global renewables investment growth, the principal effect of the crisis on the renewables scene has been to shift the center of gravity for investment and deployment away from the advanced economies and increasingly toward the developing countries, particularly the BRICS. Indeed, in 2010 the developing world actually overtook the advanced economies in terms of financial new investment in renewable energy.¹⁴⁶ As recently as 2004, this comparison produced a four-to-one ratio in favor of the advanced economies. Nevertheless, the advanced economies remain well ahead in two other categories not included in "financial new investment": small-scale and distributed capacity (such as rooftop solar panels, which have boomed in Europe during the past few years), along with public and private research and development (R & D). Global investment in small-scale and distributed renewable capacity and in

¹⁴⁴ See *Global Trends in Renewable Energy Investment 2011: Analysis of Trends and Issues in the Financing of Renewable Energy*, United Nations Environment Programme and Bloomberg New Energy Finance, 2011.

¹⁴⁵ Nevertheless, in the second half of 2011, a number of renewables companies in the United States went bust after receiving large government-backed loans through the Department of Energy. Solyndra, a California-based solar panel company, announced bankruptcy in September 2011. It was followed quickly by Beacon, a Massachusetts-based company manufacturing flywheels to be used to store electric power. These episodes have only added to the short-term hurdles now facing renewable energy in the northern Atlantic, despite the impressive recent growth rates.

¹⁴⁶ "Financial new investment" is a measure that covers money invested by third-party investors in renewable energy companies and utility-scale generation and biofuel projects. Global financial new investment in renewable energy was \$143 billion in 2010, up from \$122 billion in 2009 and the previous record of \$132 billion in 2008. Just over \$70 billion of that took place in developed countries, but more than \$72 billion occurred in developing countries.

R & D rose to \$68 billion in 2010, up dramatically from \$37 billion in 2009 and only \$26 billion in 2008.

It is true that this most recent investment spurt — particularly the small-scale and distributed capacity in the advanced economies — has been powered through the global downturn by “green stimulus” spending approved after the financial crisis in the advanced economies and China, and by the previous widespread adoption of subsidies, tax breaks, feed-in tariff schemes, and renewable portfolio standards (and other forms of targets), especially in the northern Atlantic. This particular dynamic of strong small-scale “off-grid” growth in the North — hidden within the overall global investment figures — is vulnerable, however, to a certain weakness, at least in the short term. Subsidies and feed-in tariffs for wind and solar power have recently been slashed in the United States and Europe (in a response to the second wave of the global financial crisis unleashed by the sovereign debt problems in Europe), and efforts to price carbon have slowed, particularly in the United States.

Nevertheless, the other new dynamic obscured by the global figures — the new dominance of the developing countries in global renewable energy investment — is not nearly as likely to recede as rooftop solar installations in the advanced economies. Indeed, even if the “green stimulus” were to dissipate completely in the advanced countries (as now appears likely, given the appearance of immediate financial and budgetary limitations), the recent surge in renewable energy investment in the developing world would appear even more sustainable, as investors rebalance away from the northern Atlantic to invest in the largest and fastest-growing emerging markets. This is bound to increase the dynamism and influence of the developing world (and the southern Atlantic, in particular) within the global energy economy. In the Atlantic Basin, such a development points to the continuing shift of the basin’s center of energy gravity in the direction of the southern Atlantic, a potential geopolitical development of historic significance to be analyzed further below.

2.5.3 Technological and Market Developments in Renewable Energy

This rising influence of the developing world — and of the southern Atlantic — within global renewable energy markets has been both cause (providing for larger scales) and partial effect (benefitting from innovation in the advanced economies) of the downward evolution of renewable energy costs experienced in recent years. No other energy technology has gained more from falling costs than solar power. According to Bloomberg New Energy Finance, the price of photovoltaic (PV) panel units per megawatt (MW) has fallen by 60 percent since the summer of 2008, just before the financial crisis. As a result, solar power is now competitive for the first time with the peak-time retail price of electricity in a number of sunny economies — such as the American Southwest and southern Europe — even with little or no subsidies. In many developing countries, distributed use of solar power is already competitive with diesel fuel (used in small-scale distributed generators), its main “off-grid” competitor. Wind turbine prices have also fallen significantly (18 percent per megawatt over the last two years), reflecting the same vibrant competition found all along the solar power supply chain. Further declines in the costs of solar and wind power, and other low-carbon technologies, are expected to continue to eat away at fossil fuel dominance over the coming years.¹⁴⁷ The most significant unknown in this regard, however, is how fast and completely renewable energies will ultimately displace fossil fuels.

The speed of renewable energy rollout will ultimately depend on 1) how fast renewable energy costs can fall, and 2) whether a realistic price can be imposed on global greenhouse gas emissions. Even now, the price of solar power must fall significantly before it can compete effectively with fossil fuels in electricity generation, even if governments were to increase fossil fuel prices to reflect more fully the cost of carbon emissions. The cheapest solar power now costs \$120–\$140/MW; onshore wind power in the United States costs \$70/MW and gas-fired power some \$70–90/MW; meanwhile, coal-fired electricity is even cheaper than gas and wind.¹⁴⁸

¹⁴⁷ *Global Trends in Renewable Energy Investment 2011: Analysis of Trends and Issues in the Financing of Renewable Energy*, op. cit.

¹⁴⁸ “Solar Power: A painful eclipse,” *The Economist*, October 15, 2011.

Technological innovation across the renewable energy spectrum still has a long curve to follow. In the solar industry, for example, cadmium telluride — used to make “thin film” photovoltaic cells — has the potential to displace the conventional silicon cell. Although the silicon cell remains somewhat more efficient (14 per cent to 15 percent, versus 11 percent to 12 percent), cadmium telluride “thin cells” are now cheaper — \$0.74 per watt of generating capacity compared to well over \$1.00 for the cheapest silicon panels — and they could easily become more efficient with time. Other, more efficient thin cells could be developed based on a “CIGS” semiconductor (made of copper, indium, gallium, and selenium). Applying nanotechnology might increase efficiencies and reduce costs even more significantly in the future.¹⁴⁹

The story has been much the same in the wind sector, although wind technology is now somewhat more mature than solar. However, many solar technologies (PV panels, hot water heaters), along with small hydropower, sugarcane-based ethanol and geothermal energy, are relatively mature in that they have established technologies and, like the wind sector, “a vibrant manufacturing sector and clear markets.”¹⁵⁰ Other renewable energy technologies (e.g., concentrating solar power, marine power, and most biofuels) are still in earlier phases of development. Nevertheless, although many renewable energies are mature enough to be deployed and have established manufacturers and markets, the highly competitive nature of such rapidly evolving markets tends to make them highly volatile, with boom-and-bust-driven consolidation bound to recur cyclically over the coming decades.

The world’s first renewables boom has already produced its first few busts: A biofuels bubble grew and burst in Brazil with the last recession, a solar bubble is now bursting in Europe (Spain, Germany, and Italy), and one could follow in the United States

¹⁴⁹ Ibid.

¹⁵⁰ David Reed and Pablo Gutman, “Energy+: Opportunities, Challenges and Options,” World Wildlife Fund, March 2011.

if renewables policy support does not strengthen.¹⁵¹ But these and other recent examples of retrenchment are short-term ebbs and flows driven by the interaction of the economic cycle with the shifting political and financial constraints shaping renewable energy policy; meanwhile, renewable energy's share of the energy mix is increasing in a structural fashion and at a significant rate, if from a low base. The recent busts in biofuels and solar power will not end the expansion of renewable energies: Consolidation will take place (as is now occurring), growth will be restored at a more sustainable rate (one more consistent with the emergence of shale gas, for example), and policy will adjust accordingly so as to support the newly established sustainable growth.

Nevertheless, given the length of the economic crisis and the relatively hostile political atmosphere surrounding the pricing of carbon emissions and state support for renewable energies in the northern Atlantic, growth in renewable energies may moderate for some time in the United States and the EU. Renewed economic growth, or the successful application of credible and correct energy policies (e.g., higher taxes on fossil fuels and renewed state support for renewables, albeit at levels more consistent with a reasonable integration of carbon-free renewables with the lower-cost, and potentially also lower-carbon, shale gas revolution), could unleash strong renewables growth once again. However, neither appears probable in the short run.

In the southern Atlantic the story could be very different, however, as the center of gravity in the renewable energy industries shifts to the developing world (where China dominates on the global scale), and from the northern to the southern Atlantic. Although China continues to make market inroads at the global level in manufacturing, investment, rollout, and production of renewable energies, Brazil and Mexico have made significant investment

¹⁵¹ Following rapidly on the heels of the Solyndra and Beacon debacles, in early November 2011, First Solar, the world's largest PV producer, announced it was changing its CEO, provoking an immediate 25 percent drop in its share price. First Solar shares had fallen from \$175 less than a year ago to \$60 by late October 2011. Share prices of all clean energy companies fell by nearly 15 percent in 2010, underperforming wider stock market indexes by 20 percent (see "Solar Power: A painful eclipse," *The Economist*, October 15, 2011). While such signs may seem to point to a crisis in the solar market, such potential renewables retrenchment in the northern Atlantic is likely to be nothing more than the kind of rough market turbulence one would expect in an immature but rapidly growing market, with still relatively immature but "currently maturing" technologies like solar power.

commitments to renewable energies as well. In the future, China is also likely to be a major source of investment in renewable energies in the southern Atlantic, along with the most successful large renewables companies from the northern Atlantic that will seek higher potential growth beyond their own temporarily restricted markets.

2.5.4 Obstacles and Challenges

A number of obstacles still complicate the way forward for renewable energies, even in the southern Atlantic. Foremost among them will be the fallout from the renewables bubbles in the Atlantic Basin mentioned above, particularly in the solar markets, as the overhang in excess capacity is absorbed and eliminated from the supply chain. Furthermore, the recent pullback in state support, particularly in the northern Atlantic, along with the tightening of global credit (especially for smaller players) is bound to reduce renewable energy growth rates in the EU and even the United States. The end of stimulus spending in the northern Atlantic will only reinforce this tendency. The lack of recent progress at the global climate negotiations has also precluded the formation of a sufficiently high global price for carbon emissions. The way ahead is further clouded by a broad global patchwork of subsidized electricity and fuel end-use prices, along with additional subsidies for fossil fuel production. Finally, very few countries in the developing world have proved capable of creating clear and attractive incentive schemes. Brazil has been a major exception, but it is now phasing out its feed-in tariffs, and others — such as Morocco and Mexico — have decided against such schemes, at least for now. Brazil, in the end, may be proved right in shifting now to a more competitive model, but its future success, to a large degree, will have been built upon the early years of government support through the PROINFA renewables feed-in tariff scheme, suggesting to Morocco and Mexico, perhaps, that more strictly competitive market models, at least for renewables, might still be somewhat premature, however important the goal of gradually liberalizing the electricity sector may be.

Nevertheless, even the imperfect, aggregate global incentives in place today look likely to continue spurring renewable energy investment. Granted, certain technological challenges remain:

energy storage solutions to facilitate the rollout of intermittent renewables, along with technological solutions to reduce the costs of integrating such renewables into existing power grids, and to reduce the renewable energy demand for scarce resources (such as land and water) must still be found. However, if sufficient incentive schemes can be put in place in key developing countries (even if they must be financed through arrangements with advanced economies or international and regional development banks), and if the world's fossil fuel subsidies can be gradually eliminated, renewable energy will boom.

2.5.5 Renewable Energy in the Atlantic Basin

As of 2010, the Atlantic Basin dominated the global terrain in renewable energies. Of the nearly 200GW of installed wind capacity in the world, 64 percent is located within the Atlantic Basin. Furthermore, more than 80 percent of the world's current installed capacity in solar power is located within the basin, although admittedly most is still in the northern Atlantic. However, conditions now look more favorable for rapid growth in the southern Atlantic.

Despite the numerous current barriers to short-term growth, renewable energy appears to be on the brink of flourishing in many parts of the Atlantic Basin, particularly in the South. Although China has been the principal magnet of renewables investment in the developing world — accounting for nearly \$50 billion of financial new investment in 2010, an increase of 28 percent over the previous year and nearly 25 percent of the global total — the current shift in the global balance of power in renewable energy is no longer a story of China, or even Asia, alone. In 2010, financial new investment in renewable energy grew by 104 percent to \$5 billion in the Middle East and Africa region, and by 39 percent to \$13.1 billion in South and Central America.¹⁵² Brazil alone experienced \$6.9 billion in new renewables investment in 2010, and other countries around the basin — Mexico, Argentina, South

¹⁵² *Global Trends in Renewable Energy Investment 2011: Analysis of Trends and Issues in the Financing of Renewable Energy*, op. cit.

Africa, and Morocco — also have begun to make major strides in the renewables sphere.¹⁵³

Behind China and India, Brazil has dominated renewables investment in the developing world. Brazil has also been a third force within the Atlantic Basin, behind the United States and the EU. However, in the southern Atlantic, Brazil is the clear leader, having begun to chart a serious renewable energy strategy over 30 years ago based on hydroelectric power (which now supplies more than 70 percent of the country's electricity) and sugarcane-based ethanol (which currently contributes about 30 percent of all transportation fuel; see section 3.1 on Brazil). President Rousseff has committed herself to continuing the ambitious renewable energy and climate policies of her predecessor, Lula da Silva, including an extension of the PROINFA program, Brazil's successful feed-in tariff system for wind, small hydro, and biomass. According to ANEEL, the Brazilian National Electricity Agency (and regulator of the sector), another 800MW of the total 3.3GW of renewable capacity contracted by PROINFA was expected to enter into operation in 2011 (joining the 1.27GW already installed by August 2008).

Also supporting the sector is the new ten-year plan for the expansion of renewables, ratified by the Brazilian Ministry of Mines and Energy at the end of 2010, which foresees an estimated investment of \$600 billion (BRL952 billion) over the next ten years. The ten-year plan also commits Brazil not to develop any new fossil-fueled power plants after 2014. Finally, Brazil has developed a successful new “reverse” auction system for wind power and other renewable energies, designed to replace the feed-in tariff system of PROINFA. Brazil had set a target of an additional 4GW of renewable energy capacity to be connected to the grid by the end of 2010, 777MW to be added by 2011, and another 2GW in 2012.¹⁵⁴ Over the middle run, Brazil's goal is for renewable energy (excluding large hydro) to contribute 10 percent of the electricity

¹⁵³ Ernst and Young's “renewables country attractiveness index” ranks Brazil 11th in the world in the renewables realm, Mexico 23rd, South Africa 26th, and Morocco 29th (Argentina has not yet been included in the index). The country attractiveness indices (CAI) provide scores for national renewable energy markets, renewable energy infrastructures and their suitability for individual technologies. See Ernst and Young, *Renewable energy country attractiveness index*, August 2011, Issue 30.

¹⁵⁴ Ernst and Young, “Brazil: Wind power soars in public auction,” *Renewable energy country attractiveness index*, February 2011, Issue 28.

mix by 2020. Financing from the Brazilian Development Bank (BNDES) has been critical in supporting the country's renewables expansion, covering up to 70 percent of investment costs for renewable-power projects.¹⁵⁵ On the other hand, PROINFA's 60 percent local-content requirement for renewables projects has slowed rollout to some degree (only two companies currently manufacture wind turbines in Brazil), and may have to be adjusted in the future if Brazil's ambitious renewables targets are to be met. Solar power, not included in the PROINFA incentive schemes, may also need some additional support.

Mexico is the renewables leader in Latin America, behind Brazil. The country has enormous potential in wind (upwards of 40GW) and solar power (the equivalent of 45GW just in PV panels and household solar thermal alone, and more than 60 percent the solar potential of Europe). Furthermore, the country has already developed its significant geothermal resources well enough to become the geothermal energy leader of Latin America, and is the third-largest geothermal producer in the world (with 960MW of installed geothermal capacity, which provide 3.24 percent of the country's electricity).

Nevertheless, a similar — if less rigid — state dominance to that which Pemex exercises in the oil sector also characterizes the Mexican electricity sector, where the Federal Electricity Commission (CFE) wields a vertically integrated near-monopoly. According to the CFE's 15-year energy plan (2010–2024 Program for Work and Investment in the Electricity Sector, with the acronym POISE in Spanish), an additional projected 38GW of electrical capacity is needed to meet demand between 2010 and 2025. As a result of CFE's monopoly, however, Mexico suffers from a lingering lack of investment in new electrical capacity. Independent power producers have recently been allowed, but the CFE's least-cost mandate has precluded any IPPs from winning generation contracts to produce electricity from relatively more expensive renewables. This situation has been aggravated by CFE's very low, subsidized end-use electricity tariffs, which at current PV costs, give rooftop solar installations in Mexico payback times of more than 40 years for businesses and more than 60 years for

¹⁵⁵ Garten Rothkopf, *A Blueprint for Green Energy in the Americas*, Vol. 2, Strategic Analysis of Opportunities Prepared for the Inter-American Development Bank, 2009.

households. In addition, there are not yet any formal power off-take support mechanisms to stimulate the rollout of renewable energy.¹⁵⁶

Nevertheless, the Mexican government has established a renewable energy target of 25 percent of total energy consumption by 2012 and 35 percent by the end of the current 15-year plan in 2024. Another target raises the current renewable energy electrical capacity from 3.3 percent of the total to 7.5 percent by 2024. By 2014, the government plans to oversee the installation of 3GW of wind capacity — six times the current 500MW. In 2008, wind accounted for only 0.2 percent of Mexico's electricity mix, but the government has targeted 3.1 percent by 2024. Enormous wind potential exists in Oaxaca, where a 2GW facility is due to come on line in 2013.¹⁵⁷ The government also continues to demonstrate its commitment to renewables through the ongoing articulation of a specific renewable energy regulatory framework. The latest framework, adopted in 2009, consolidated an earlier self-supply regime in which IPPs may generate with renewables through contracts with industrial users, a regime that so far accounts for all of Mexico's wind and solar rollout. Indeed, despite the fact that Mexico still does not provide any direct state support, the 2009 regulatory framework was attractive enough to provoke a boom in investment. In 2010, Mexico took the lead among Latin American countries (excluding Brazil) in renewable energy investment, which grew by nearly 350 percent over the previous year (mainly in wind, but also in geothermal).¹⁵⁸ The World Bank and the IDB have also expressed interest in supporting the financing of renewable energy projects in Mexico. Spanish investment from Iberdrola, Acciona, and Gamesa (all active in wind and/or solar power) has already begun to arrive.

Mexico will likely need to create a formal state support mechanism for renewables in order to significantly increase the rate of renewables rollout. The electricity sector will also need to be further liberalized if more private-sector participation is to be successfully garnered, particularly in the geothermal sector, in

¹⁵⁶ Ernst and Young, "Country focus — Mexico," *Renewable energy country attractiveness index*, November 2010, Issue 27.

¹⁵⁷ Ibid.

¹⁵⁸ Global Trends in Renewable Energy Investment 2011: Analysis of Trends and Issues in the Financing of Renewable Energy, op. cit.

which CFE still exercises a monopoly over all subsoil hot water and steam resources. Still, Mexico currently ranks as the key renewables player in the region after Brazil.

Morocco has promoted renewable energy for 25 years now, although in recent years, the goal of significant renewable energy rollout has been pursued more vigorously, partly as a way to begin to liberalize the Moroccan energy sector. The government's renewables plan aims to generate 20 percent of the country's electricity from renewable energy by 2012 and 42 percent by 2020. If successful, such a drive will increase the current 6.1GW of installed electrical capacity to 14.6GW in 2020, by which date domestic electricity demand is projected to have doubled (with an expected tripling by 2030). Major wind and solar programs have been launched with the goal of installing 2GW of capacity by 2020, requiring some \$11 billion in new investment over the coming decade. To support these ambitious targets, in 2010, the government introduced a number of renewable energy laws, including the breakup of the monopoly of the state-owned Office National de l'Electricite (ONE) over the production of renewable energy and the creation of a more liberalized market for the generation of renewable energy by the private sector (although the obligation to supply renewable energy through ONE to the national grid is still in force).

Morocco's potential wind power is significant, with an estimated technical potential of some 1,600MW, mainly onshore.¹⁵⁹ At the end of 2010, installed wind capacity came to 286MW (with 119MW installed in 2009 and 33MW installed in 2010). As part of the above-mentioned target of 2GW by 2020, an estimated 720MW is now under construction by the private sector, and an additional 1GW is being tendered by ONE through a \$3.5 billion integrated national wind energy program. The Center for Renewable Energy Development suggests that around 4GW to 7GW of wind power could be installed by 2020, requiring investment up to \$14 billion.¹⁶⁰

¹⁵⁹ According to a study undertaken by the Center for Renewable Energy Development. See Ernst and Young, "New country focus — Morocco," *Renewable energy country attractiveness index*, May 2011, Issue 29.

¹⁶⁰ Ibid.

Solar resources are even more abundant in Morocco. So far, only one 20MW concentrated solar plant has been commissioned as part of a 470MW hybrid gas plant. Solar PV capacity is also currently negligible at 13MW. In late 2009, however, the Moroccan government launched a \$9 billion solar plan to install 2GW of solar capacity by 2020, principally through the construction of five large CSP plants. Once completed, these solar projects will contribute an estimated 18 percent of the country's yearly electricity generation. The first of these new CSP plants — a 500MW facility at Ouarzazate — will be the world's largest solar power plant when it comes on line in 2014. The European Investment Bank (EIB) is also considering a €500 million loan to help finance the first stage of this project. Although Morocco's hydropower capacity comes to around 1.2GW and 30MW for large- and small-scale hydro, respectively, most of the country's hydro potential is nearly exhausted.¹⁶¹

There is also enormous potential for Morocco to integrate itself into both Europe's electricity network and the EU's ambitious plans to increase renewable energy's contribution to the primary energy mix (20 percent by 2020) and to reduce carbon emissions by 20 percent from 1990 levels in 2020.¹⁶² Two enormous regional solar projects — one public (the EU's Mediterranean Solar Plan, or MSP, with a projected 20GW) and one private (the German-led DESERTEC, with a projected 40GW) — offer Morocco the chance to attract significant investment, significantly ramp up its solar rollout, renew its electricity infrastructure, and eventually export significant amounts of renewables-based electricity to Europe. Morocco is the only African country with a direct interconnection into Europe — a 1.4GW-capacity link with Spain. It also has an interconnection with Algeria, and has plans to connect with Mauritania. Morocco is actively seeking opportunities to integrate and collaborate with European markets, and it has already expressed a willingness to export electricity when this becomes feasible. Such a posture will help facilitate joint projects to support the EU's ability to meet its ambitious 2020 and 2030 energy and emissions targets. Although the MSP and DESERTEC projects are ambitious and face many

¹⁶¹ Ibid.

¹⁶² A March 2010 study by PricewaterhouseCoopers concludes that it would be "technically" possible for renewable electricity to power Europe exclusively by 2050, by interconnecting the European and North African power grids.

obstacles (particularly financial and political), the potential they hold for Morocco could be enormous.¹⁶³

So far Morocco has eschewed a direct renewable energy support scheme (such as feed-in tariffs or direct tax incentives) for a competitive bidding regime (as has Mexico). On the other hand, some private incentives are in place, such as the EnergiPro initiative that allows industrial firms to invest in renewable energy projects under 50MW capacity in order to meet their own energy needs, and guaranteed access to the grid along with special incentivizing tariffs for the excess electricity produced. Nevertheless, Morocco may find it necessary to introduce further incentives, perhaps with aid or concessionary finance from the advanced economies or the multilateral development banks.

In a country dominated by coal (90 percent of the electricity mix), renewable energy accounts for only 400MW of South Africa's installed electricity capacity, or less than 1 percent of total generation. The target for 2013 is around 4 percent of total generation, or some 3GW. At the moment, South Africa has only 4MW of installed wind capacity. Nevertheless, the new Integrated Resources Plan projects new build of renewables capacity over the coming two decades to total 17.8GW (solar PV 8.4GW, CSP 1GW, and wind 8.4GW), accounting for more than 40 percent of all new electricity capacity to be built in the country until 2030, and for more than 9 percent of the electricity mix by the same year. The IRP calls for a doubling of current installed generation capacity to over 80GW, with new coal-fired build contributing only 15 percent of the total to 2030: the "green" portion of this build program — based on solar PV, solar CSP, and wind power — is projected to cost some \$120 billion. There are also ambitious plans to roll out solar water heaters in residences, with the Cape Town municipal government taking the lead. The South African government has set a target for renewable energy to contribute 10,000 gigawatt hours

¹⁶³ The "Paving the Way for the Mediterranean Solar Plan" project was expected to be launched in 2010. The project seeks to pave the way for the establishment of a harmonized legislative and regulatory framework in the Euro-Mediterranean region conducive to large-scale renewable energy rollout, regional trade in renewable electricity, deployment of energy efficiency technologies, and improvements in intra- and interregional knowledge transfer in the realm of renewable energies, particularly solar power. See "The Mediterranean Solar Plan," EU-MED Relations, February 10, 2010, http://eu-med.blogspot.com/2010/02/mediterranean-solar-plan_10.html.

of final energy consumption by 2013, and solar water heating is projected to contribute up to 23 percent toward this target.¹⁶⁴

As the global renewable energy industry focused on the next round of climate talks in Durban in December 2011, the South African Government ended months of delay by issuing a Request for Proposals (RFP) under the REFIT program, inviting developers to bid for renewables projects. Developers will sell the power in an off-take agreement to an agreed counterparty, which has yet to be confirmed (although the likely candidate is the state-owned nearly monopoly, Eskom). According to the energy regulator, NERSA, bids are likely to be based on initial non-price criteria such as the location of the project and the Black Economic Empowerment Act (see the section on South Africa). If developers meet these requirements, projects will then be selected based on the lowest price. The initial procurement, consisting of five bidding rounds, is likely to be for 3.5GW of projects, expected to be operational before 2016.

However, after cuts to the original published FIT rates for renewables in 2009, there is still lingering uncertainty over what the final REFIT tariff levels will actually be in the end. The source of South Africa's energy is particularly critical at the moment, as total energy demand has already returned to its pre-recession levels and the pressure of growing demand upon the country's electricity supply infrastructure has never been more acute, particularly in the wake of the "power crisis of 2008" and the subsequent scare over potential problems with electricity supply during the 2010 World Cup (a fear that, although not unfounded, was not realized in the end).

As Africa's leading electricity producer, with 40GW of generation capacity and provider of around 95 percent of the electricity used in South Africa, state-owned (and still near-monopoly) Eskom has served as a lightning rod in the country's renewable energy debate. In April 2011, however, Eskom established a new renewable energy

¹⁶⁴ To actively encourage and promote the widespread implementation of solar water heating, Eskom has rolled out a large-scale solar water-heating program. This program will assist South Africans when buying SABS-tested solar water heaters to replace their conventional water heaters. In addition to the rebate to be given upon installation of solar water heating, many insurance companies are now allowing consumers to put their claim value toward a solar system, or are offering a solar water heater as a replacement in the event of a burst conventional water heater.

division (Eskom Renewables Business). The African Development Bank has loaned \$365 million to Eskom to finance its wind and solar projects, which will each produce 100MW. Although the company has expressed an interest in developing additional solar projects, many believe that it is not doing enough, as more than 80 percent of its current production still comes from coal-fired plants. For better or for worse, Eskom certainly holds one of the keys to South Africa's renewable energy future (see section 3.2 on South Africa).

Less than 1 percent of South Africa's energy mix currently comes from renewable energy. In fact, Eskom is currently in the process of constructing two new coal-fired power stations in Kusil and Medupi (one of them is even backed by a World Bank loan). South African environmentalists claim that the government's official target of 23 percent of electricity to be generated from renewable energy by 2030 (as projected in the Integrated Resource Plan 2010) is not ambitious enough. Meanwhile, South African industry continues to claim that the government's targets are unrealistic, given the enormous challenge implied just by the need to build even enough cheap coal-fired plants in order to be able to keep up with rising future demand (which will continue to be underpinned by the new BRICS' current economic growth and the revolution of rising expectations among the poorer black South African masses). Eskom, however, officially anticipates that more than 42 percent (17GW) of new power will come from renewable energy over the next 20 years, in line with the Integrated Resource Plan. How this will actually happen will provide for much potential drama in South Africa (see section 3.2 on South Africa).

The potential of solar energy in the Northern Cape is huge; across South Africa as a whole, it is greater than in Spain or the United States. The government has set aside \$2 million for a planned a 5GW solar park near Upington in the Northern Cape. South Africa also has the potential for further hydroelectric development. The DoE estimates that there are 6,000 to 8,000 sites that could be used for small-scale hydroelectric projects. Meanwhile, the British-based energy company ENER-G Plc constructed the first of five waste-to-energy plants in Johannesburg. The site was expected to start generating energy as early as October 2011 and ENER-G

hopes to sell the power to Eskom Holdings Ltd. through power purchase agreements.

The obstacles to rapid renewables rollout remain large in South Africa, particularly given the dominant and increasingly uncomfortable position of coal-based electricity giant Eskom. Nevertheless, despite orthodox critiques in South Africa claiming that the government's goal of 9 percent of installed capacity and 23 percent of generation to come from renewables by 2030 is far too ambitious and unrealistic given the country's circumstances, it must be noted that Spain went from nothing to 17GW of renewable power capacity in less than ten years — less than half the time skeptics fear it will take South Africa. However, much could be done to improve the horizon for renewable energy in South Africa if the regulatory regime and the incentives schemes for renewables can be made clearer and more attractive.

2.6 Recent and Future Trends in the Atlantic Basin Power Realm

2.6.1 International Interconnection and Electricity Market Integration

By far the most important recent trend in the Atlantic Basin power realm — as in the transportation sector — has been the rapid rollout of renewable energies, first in the northern Atlantic and now in the southern. Nevertheless, although renewable energy will likely remain the fastest-growing electricity source far into the future, other developments are under way that, if successful, will help to underpin this renewables expansion, allowing for an ever-increasing share of renewables to be technically absorbed and integrated into the world's generation mixes.

Because most renewable energies (such as wind and solar) are intermittent sources, electricity systems must have enough of a flexible power source — capable of expanding or contracting output rapidly, and at relatively low cost — to cover peak demand loads, particularly at the moment of the day (or seasons of the year) when renewables production tapers off. Currently, natural gas is the electricity source best positioned to provide this flexible cushion (or power-peaking adjustment) between the stable baseload generation (typically provided in the North by nuclear power and

coal, and in the South by hydropower and, to some extent, oil), the intermittent entrance of renewable energy into the grid, and hourly fluctuations of demand. Demand tends to peak during the central part of the working day from 10:00 a.m. to 4:00 p.m., and again during the early evening when solar power is tapering, and to trough during the predawn, early-morning hours when wind power tends to peak.)

The shale gas revolution might provide the world enough gas to complement a relatively large share of renewables in the world's generation mixes. The rollout of a "gas bridge" to a low-carbon future is one of the key trends in the Atlantic Basin power realm, and will be explored below.

Two other developments, now under way in incipient form, could also enhance the capacity of the world's electricity systems to absorb ever higher amounts of intermittent renewable energies: 1) the introduction of smart grids, and 2) the international expansion of electricity markets through growing international interconnections and deepening market and regulatory integration. Smart grids increase the electricity system's capacity for storage, which provides for supply buffers to compensate for the intermittency of renewables. International interconnections allow isolated systems to link up, providing a broader base of potential regional surpluses that can be transmitted to other parts of the interconnected system at times of shortage. This allows for complementary intermittencies between systems to interlock and even out the supply-demand balance more easily throughout the day's demand cycle, even with significant amounts of renewables involved in the mix.

Nordpool and the European Single Electricity Market are the principal examples of international grid interconnection and market integration in the northern Atlantic, and SIEPAC and the Southern African Power Pool are the primary examples of the trend in the South. Nordpool, linking the grids of the various Scandinavian countries, has demonstrated that a broader interlocking transnational grid adds flexibility to the management of entire systems, as well as to each of the national components, allowing for a much higher proportion of the generation mix to come from intermittent renewables. The addition of smart grids

will only enhance this management flexibility. On the other hand, the failure of the European Single Electricity Market to develop more than marginal interconnection capacity with a number of countries on the EU's periphery has left a series of "energy islands" — such as Spain — isolated from the densest parts of the European grid, limiting their ultimate capacity to absorb renewable energy into their generation mixes.¹⁶⁵

Meanwhile, the Southern African Power Pool, inspired to a large degree by Nordpool, is in its infancy, but it has already gone farther than any other attempt at creating a broader, transnational market for electricity. The SIEPAC interconnection system of Central America is about to be inaugurated. Although the movement to link up national grids into larger, more flexible, and more resilient international systems is still in its incipient stage, its potential to increase the ultimate capacity of renewables absorption in the Atlantic Basin, as well as the efficiency of the energy system in general, is enormous.

2.6.2 *A Gas Bridge Across the Atlantic to a Low-Carbon Future?*

The shale gas revolution has the potential to roll out a "gas-bridge" to a low-carbon future dominated by current and future generations of modern renewables. As the MIT "Future of Gas" study concluded: "There has been a growing recognition that the low-carbon content of natural gas relative to other fossil fuels could allow it to play a significant role in reducing carbon dioxide emissions, acting as a 'bridge' to a low-carbon future."¹⁶⁶ Large quantities of cheap gas would compete with coal and oil, eventually significantly displacing them within the energy mix of the Atlantic Basin, both in generation (through substitution) and in transportation (through potential application of GTL technology).

Wider use of gas could potentially reduce carbon emissions significantly over the middle run, buying crucial time in the struggle to cap CO₂ concentrations, until renewables are capable of reaching mass scales some 20 to 30 years into the future. Furthermore, a higher share of gas within the electricity mixes

¹⁶⁵ The limitation imposed on Spain from the lack of significant interconnections with France is partially compensated for by the incipient smart grid that Red Eléctrica (REE), the Spanish transmission system operator, has begun to pioneer.

¹⁶⁶ MIT, op. cit.

of the Atlantic Basin might also enhance the capacity of national electricity systems to absorb ever-higher shares of intermittent modern renewables — a flexible capacity and potential that would be augmented further still by the application of smart grid technology, international interconnections between national electricity systems, and transnational energy market integration.¹⁶⁷

However, a risk exists that a successful shale gas revolution will instead compete with the current renewables rollout effort, as gas prices become permanently delinked from those of oil, increasing even further the current additional cost differential associated with renewable energies. A number of voices in both the conventional and unconventional gas worlds now argue that the shale revolution should be harnessed to reduce carbon emissions more quickly and more cheaply in the short run than could otherwise be achieved with the current pace of the renewables rollout.¹⁶⁸ Rather than committing substantial state support in a continuing effort to promote the rollout of the current generation of renewables, cheaper gas should be used to substitute first for coal and then for oil, with the cost savings invested — not in state support for current rollout, but rather in renewables R & D. Such voices argue that this “pure gas bridge” strategy, by redistributing investment from current rollout to future research breakthroughs, will allow for innovation to drive down the cost of renewable energy more efficiently and rapidly over the long run.

The countries of the Atlantic Basin, but particularly those of the southern Atlantic, should exercise critical skepticism with respect to the “pure gas bridge” option. First, many of the dominant players in the shale world, including many of the principal IOCs and

¹⁶⁷ The MIT study of the future of gas concludes: “Additional gas-fired capacity will be needed as backup if variable and intermittent renewables, especially wind, are introduced on a large scale. Policy and regulatory steps are needed to facilitate adequate capacity investment for system reliability and efficiency. These increasingly important roles for natural gas in the electricity sector call for a detailed analysis of the interdependencies of the natural gas and power generation infrastructures.” See MIT, *op. cit.*

¹⁶⁸ For example, according to the MIT study: “Increased utilization of existing natural gas combined cycle (NGCC) power plants provides a relatively low-cost short-term opportunity to reduce U.S. CO₂ emissions by up to 20 percent in the electric power sector, or 8 percent overall, with minimal additional capital investment in generation and no new technology requirements. . . . A combination of demand reduction and displacement of coal-fired power by gas-fired generation is the lowest-cost way to reduce CO₂ emissions by up to 50 percent. For more stringent CO₂ emissions reductions, further de-carbonization of the energy sector will be required; but *natural gas provides a cost-effective bridge to such a low-carbon future.*” See MIT, *op. cit.*

NOCs, have done relatively little to promote renewable energy R & D in the past. In fact, they have often obstructed, in many ways, the transformation to a low-carbon economy. Shale offers these players the opportunity to survive with much of their current global influence by slowly phasing themselves out of the oil sector — developing gas to replace it — while still remaining very profitable and absolutely central in geopolitical terms. As a result, gas should be made to share with renewables — even in the short run — the new market share to be wrested from oil and coal. Such a strategy could be called an “integrated gas bridge” option, one in which the current renewables rollout would bear at least some of the weight of the gas bridge.¹⁶⁹

The recent MIT study on the future of natural gas agrees:

“A more stringent CO₂ reduction of, for example, 80 percent would probably require the complete decarbonization of the power sector. This makes it imperative that the development of competing low-carbon technology continues apace, including CCS for both coal and natural gas. It would be a significant error of policy to crowd out the development of other, currently more costly, technologies because of the new assessment of the natural gas supply. Conversely, it would also be a mistake to encourage, via policy and long-term subsidy, more costly technologies to crowd out natural gas in the short to medium term, as this could significantly increase the cost of CO₂ reduction. . . . Natural gas can make an important contribution to GHG [greenhouse gas] reduction in coming decades, but investment in low-emission technologies, such as nuclear, CCS, and renewables, should be actively pursued to ensure that a mitigation regime can be sustained in the longer term.”¹⁷⁰

Second, it would be foolhardy for any country in the Atlantic Basin — but particularly for the emerging economies of the southern Atlantic — to forgo the burgeoning opportunities that exist today to develop a renewable energy sector (including, in many cases, the

¹⁶⁹ In some markets, existing regulation does not provide the appropriate incentives to build incremental backup capacity with low load factors, and regulatory changes may be required. See MIT, *op. cit.*

¹⁷⁰ MIT, *op. cit.*

associated manufacturing and service sectors), just on the hope that more intensive R & D today (undertaken primarily in the northern Atlantic) will produce a future renewables rollout 20 to 30 years in the future powerful enough to compensate for the significant constraints such a strategy imposes on renewables rollout in the short- and mid-run future. Even if such a strategy proved successful on a wide scale, many countries would in the meantime potentially lose out on the opportunity to improve the competitiveness of their economies within the budding global low-carbon economy.

Finally, prudence argues for pursuing an “integrated gas bridge,” as opposed to the pure gas-bridge option (which would reduce the current renewables effort to just R & D). It is far from clear that shale gas will overcome the various potential environmental risks that have been identified. Even should the fracking controversy be resolved positively for the shale community, there remains the risk that the global industry will pursue shale exploitation faster than it can guarantee that fugitive emissions of methane will not leave shale gas, in the end, with an even more significant carbon footprint than oil or coal. Under current global geopolitical, economic, and energy circumstances, shale gas should be given, at least for now, the benefit of the doubt. Under no circumstance should shale be allowed to constrain the growth of renewable energies.

Furthermore, rather than favoring gas over renewables in the short run, it would also be prudent to maintain something of a balance between different interest groups and political power bases within the national energy matrix (hydrocarbons versus renewables, for example). Such a policy would facilitate the state’s capacity to develop a more strategically balanced and farsseeing energy policy, one that would be more open to flexible pragmatic evolution and more capable of providing for perceived policy continuity over time — an essential variable in the potential rate of investment in both fossil fuel and alternative energy, particularly in developing countries.

However, even if the United States or the EU were to follow a pure “gas bridge” scenario, undercutting the future of the current generation of renewables (for the theoretical benefit of a future generation), renewables rollout is likely to carry on in the southern Atlantic, where the current generation of renewables will continue to drive down costs further (through increased scale and

movement along various learning curves). Any technological and economic boost to the next generation of wind, solar, and biomass energy that would come from a diversion of U.S. resources away from current support to R & D in future technology would only benefit the southern Atlantic countries, eventually, as they could choose to adopt future technology as they saw fit. Under such a scenario, southern Atlantic countries would seize the geopolitical and diplomatic benefits of becoming the Atlantic Basin's energy and climate change pioneers, in terms of both the vigor and consistency of public policy, and the depth and dynamism of individual national low-carbon efforts.

3. Focus on the Southern Atlantic Basin

3.1 God Must Be Brazilian: Brazil, Energy, and the Atlantic Basin

For more than 30 years now, Brazil has pursued a remarkably coherent energy policy. This is not something that can be said for most countries. Indeed, Brazil responded to the energy shocks of the 1970s more clearly, energetically, and effectively than nearly all other nations — with the possible exceptions of Japan and certain European countries — and certainly more so than any other developing country. Once hyperinflation had been overcome by the Real Plan and the first years of the Cardoso administration, the country went further by beginning to open up and liberalize the hydrocarbons sector in 1997, a move that stimulated exploration and production, and eventually led, a little more than ten years later, to the pre-salt boom.

This should not come as a surprise to those familiar with global economic history, and in particular with Brazil's economic experience. Prior to the tenfold increase in world oil prices during the 1970s — and the attendant international macroeconomic instability of that decade — Brazil's newly industrializing economy experienced significant sustained economic growth, with growth rates in the high single digits, rivaling those of the emerging markets today. In fact, Brazil was considered part of the elite group of developing countries at the time known as the "NICs" (the newly industrializing countries).

It would be stretching the argument to claim that Brazil's debt crisis of the 1980s — along with the periodic bouts of hyperinflation that its economy suffered during that "lost decade" — was caused solely by the energy crisis of the previous decade. However, it is clear that the oil price shocks did much to blow Brazil off its earlier economic trajectory, given its very high dependence at the time on imported oil. Even as late as 1999, after years of increased domestic oil production, Brazil's oil import bill accounted for as much as 15 percent of the country's account deficit. With hindsight, Brazil's policy to introduce sugarcane-based ethanol, beginning in

the 1970s, as a strategy to reduce such external dependence, now appears prescient. Brazil's early biofuels strategy can certainly be understood today, in light of the heightening instability that this external dependence came to inject into the Brazilian economy over the years. Much of the difficulty that Brazilian policymakers experienced in the 1980s in maintaining stable prices, and in securing consistent and sustainable growth, stemmed from the volatility of global oil prices and the distortions they introduced into the domestic economy via the wide channel of high import dependence. That Brazil was finally able to tame inflation only during the 1990s, a period of relatively low and stable oil prices, should come as no surprise.

Before Brazil began its strategic investment in ethanol, the country's total external energy-dependence ratio was more than 35 percent (meaning that, of all energy consumed in Brazil, 35 percent had to be imported). This dependency had fallen to 25 percent by 1990, as ethanol began to replace petroleum products for transportation fuel, and as domestic oil production began to rise sharply during the 1980s, quadrupling in ten years (from the 1970 level of 172,000bd to 650,000 in 1990). Beginning in 1997, however, during the partial liberalization of the Brazilian petroleum sector, oil production rose so dramatically (to well over 2mbd) that by 2009, the country was self-sufficient in oil, leading to a small net export surplus during the last two years. These two major developments in the transportation liquids sector (increased ethanol and domestic oil production) have dramatically reduced the level of Brazil's external energy dependence to less than 5 percent today.¹⁷¹

Few countries have reduced their external-energy dependence as dramatically as has Brazil since the time of the first oil-price shock nearly 40 years ago. Brazil's focus on a long-term strategic energy vision, and its evolving policy pragmatism in pursuing that vision, have been the key factors behind its success in reducing dependence on imported energy. Interestingly, Brazil relied on

¹⁷¹ Brazil's current external energy dependence is concentrated in external coal dependence (around 70 percent, multiplied by coal's 5 percent share in the primary mix, yielding 3.5pp) and external hydroelectric dependence (7 percent, multiplied by hydro's 15 percent share in the primary mix, yielding 1.0pp). From this must be subtracted the weighted percentage of net oil exports, that is, 5 percent net exports multiplied by a 40 percent share in the primary mix, yielding a negative 2.0pp for the external dependence ratio, which currently is no more than 3 percent.

both state intervention and partial privatization and liberalization to achieve this. The state was the prime mover behind the ethanol strategy, harnessing the private sector to boost production through financial incentives and mandates; but it was the Brazilian state's relinquishing of its monopoly over oil (along with the other liberalization and regulatory reforms included in the Petroleum Investment Law of 1997) that unleashed Petrobras onto the frontier of deep offshore oil, both at home and abroad. Brazil's capacity over the long run to strategically mix state intervention with economic liberalization in an appropriate and successful fashion has been crucial to the country's push to reduce foreign energy dependence, just as the country's pragmatic approach to macroeconomic policy management over the last 20 years has been the key to this emerging market's economic stability and growth. This combination of energy and macroeconomic pragmatism has been a central catalyst to Brazil's incipient emergence as a geopolitical power.¹⁷²

The consolidation of a pragmatic policy tradition in Brazil bodes well for the country, as it now faces an energy horizon that promises to be as volatile and unpredictable as in the past. A number of energy challenges have emerged over the last decades — particularly the constraints imposed by fossil fuel-induced climate change — that continue to require the close attention of the country's strategic thinkers and policymakers. Paradoxically, such challenges now threaten the other success of Brazil's energy policy over the years: the country's relatively “renewable” or “low-carbon” energy mix.

Brazil's primary energy mix is made up of more renewable energy than any other large economy. Of the more than 11 quadrillion Btus of energy consumed in Brazil annually, approximately 40 percent originates from petroleum crude and other related liquids (NGLs, condensate, feedstocks), 18 percent from sugarcane products (ethanol and bagasse), 15 percent from hydropower, 10 percent

¹⁷² Indeed, macroeconomic stabilization and energy transformation have been Brazil's two greatest achievements, in policy terms at least. More than any other policy accomplishments, Brazil's macroeconomic and energy policies have been the key to its sudden emergence as one of the BRICS, and as a new giant in the geopolitics not just of the Atlantic Basin, but of the world. In this sense, Brazil is everyone's key strategic partner in the southern Atlantic, and it is the country with the most to gain, both for its people and for its legacy to world history, from engaging the incipient discussion on the strategic implications of imagining a new Atlantic Basin.

from traditional biomass (firewood), 8 percent from natural gas, 5 percent from coal, 2.5 percent from other renewable energies (wind, solar), and 1.5 percent from nuclear power.¹⁷³ More than 45 percent of Brazil's mix comes from renewable sources (sugarcane products, hydropower, firewood, and other renewables) compared to only 7 percent in the OECD on average (where firewood use is negligible, hydropower is far less dominant, and nuclear power is much more prominent).

However, this “renewable” criterion is deceptive because it includes traditional biomass, which, while being renewable, also releases greenhouse gases such as carbon dioxide and methane. Expressed with a different criterion, the share of “low-carbon” energy sources (including sugarcane products, hydropower, and modern renewables, but excluding firewood and adding nuclear) comes to only 37 percent of the primary mix. On the other hand, an adjusted “lower-carbon mix” for Brazil (adding natural gas into the low-carbon energy category) returns this rate to 45 percent. But a relative comparison with the developed countries, based on this lower-carbon criterion, does not look nearly so impressive for Brazil as did the strict “renewables” comparison, given that these countries consume far more nuclear power and natural gas than does Brazil, bringing their lower-carbon levels to nearly 40 percent of their primary energy mixes.

Still, Brazil's decades-long policy thrust on renewable energies has been impressive and relatively unique by any measure. Not only has Brazil managed to increase the output of domestic energy (both renewable and nonrenewable), reducing external dependence to the margin, but it has also significantly increased its low-carbon energy output on both sides of the principal energy infrastructure divide: in electricity generation (with hydropower and budding bagasse and wind sectors) and in transportation fuels (with sugarcane ethanol). No other country has yet achieved this. Even in Europe, where renewable energy penetration has risen rapidly in recent years, the share of biofuels in the transportation fuel mix is still

¹⁷³ Traditional biomass currently provides for 10 percent of Brazil's total primary energy mix (down from 14 percent in 2007). Interview with Alexandre Uhlig, director of sustainable development, Acende Brasil, June 2011.

far below the target of 10 percent, compared with more than 25 percent in Brazil.¹⁷⁴

As a result, the energy sector in Brazil currently emits far less CO₂ than the energy sectors of most other countries. Furthermore, only one-fifth of Brazil's total greenhouse gas emissions (most of which are released as a result of land-use practices such as agriculture and deforestation) come from the energy sector. Per capita energy emissions are particularly low: only 1.9 tons of CO₂ per capita, which is less than one-fifth of the OECD average and less than half the global average. Without Brazil's 40-year investment in renewable energy, the primary energy mix would be far more carbon-intensive. Indeed, energy sector emissions would be double their current levels and total national emissions would be 17 percent higher.¹⁷⁵

But Brazil's "low-carbon" energy mix is not yet fully consolidated, and a number of recent developments threaten past gains — unless a consistent policy focus remains on channeling sufficient investment into an optimum mix of low-carbon energy sources and infrastructures. The first group of threats concerns hydropower. There is growing public opposition (both local and environmental) to the construction of large hydroelectric dams in Brazil. The large public demonstrations against the construction of the mammoth Monte Belo dam and hydroelectric plant recently approved by the government casts at least some doubt over the future role of large-scale hydropower in Brazil. The future of hydropower is put into question even further by the projected effects of climate change on hydraulic patterns, which could significantly reduce Brazil's future hydroelectric output and ultimate potential.¹⁷⁶ Nevertheless, Brazil could still compensate for the potential future limits on the expansion of so-called large hydro, but replacing

¹⁷⁴ Installed hydroelectric capacity in Brazil comes to more than 75 percent of the country's total installed capacity, and ethanol supplies 40 percent of gasoline demand.

¹⁷⁵ See Christophe de Gouvello, et al., *Brazil Low-carbon: A Country Case Study*, World Bank, 2010.

¹⁷⁶ A phenomenon known as the "Amazon dieback," together with the shorter-term effects of deforestation by fires, could reduce rainfall in the Central-West and Northeast regions, resulting in smaller crop yields and less available water for hydropower-based electricity. Some advanced models suggest that much of the eastern part of the Brazilian Amazon region could be converted into a savanna-like ecosystem before the end of this century. See Vergara, Walter and Sebastian M. Scholz. *Assessment of the Risk of Amazon Dieback*. Washington, DC: The World Bank, 2011.

it progressively, not with coal or even necessarily gas, but with small-scale hydroelectric plants, particularly in the central and southern regions.¹⁷⁷

The second threat is that Brazil will experience an upward creep in fossil fuel use as a proportion of the energy mix, along with a corresponding rise in energy-induced emissions. Already, in recent years, increased diesel demand (which has not yet been completely replaced by Brazil's incipient biodiesel production) has pointed in this direction. Unless growth in the demand for electricity can be moderated, or until other low-carbon electricity generation fills what could be a growing supply-demand gap left by a maturing and constricted hydropower sector in the future, the temptation for Brazil could be to rely increasingly on cheap thermal plants fired by either coal or heavier petroleum products, at least in the short run. Even the continued growth of 3 percent a year in hydroelectric capacity expansion that the government projects for the coming decade — assuming that public opposition and the early effects of climate change do not constrain this growth rate even further — will be insufficient to keep pace with Brazil's electricity demand growth, which is expected to rise by 5 percent a year on average until 2020. Given that hydropower accounts for anywhere between 65 percent and 80 percent of the country's electricity production, such a growing potential supply-and-demand gap represents a serious challenge for the future.¹⁷⁸

Furthermore, in the wake of the nuclear disaster in Japan, growing opposition to nuclear power — one of the obvious low-carbon candidates to replace hydro in the future — has questioned the wisdom of the government's nuclear expansion plans. Although the Brazilian government has recently reaffirmed its previous

¹⁷⁷ Small-scale hydropower (with capacities of 50MW or less) is generally considered more environmentally and socially friendly than large-scale hydro. It also draws less opposition from local groups and environmentalists. For this reason, more constraining definitions of "renewable energy" typically exclude large hydro but include small hydro. According to such a definition, Brazil's "renewable energy" share in its primary energy mix is not nearly as impressive as in the definition we have used above. Therefore, it is unlikely that Brazil's substantial contribution to carbon emissions thus far will be sustained in the future unless Brazil continues with a rapid rollout of wind and solar power, along with electricity system overhauls to increase energy efficiency all along the electricity supply chain. Brazil will also have to take significant steps to reduce emissions from the agricultural sector and from deforestation, the two sources of the bulk of its contribution to climate change.

¹⁷⁸ Economist Intelligence Unit (EIU) — Business Latin America, "Brazil: Changing energy mix," June 13, 2011.

decision to build several new nuclear power plants, this might not be enough to head off further inclusion of coal and oil into the generation mix. Natural gas, however, could offer a convenient lower-carbon option in the short and middle runs. Both reserves and production of gas have increased significantly in recent years, and enough potential is projected into the future for gas to be considered as a potential lower-carbon energy source for a bridge to a low-carbon future (and not just on the generation side, but in transportation as well).¹⁷⁹

Despite the challenges summarized above, Brazil has long been — and, because of the opportunities before it, could remain — a leader in the global fight against climate change. First, Brazil hosted the United Nations Conference on Environment and Development in 1992. Known internationally as the Rio Earth Summit, the conference agreed on the creation of the United Nations Framework Convention on Climate Change (UNFCCC) and, in turn the Kyoto Protocol. Recognizing the need for low-carbon pathways to future growth, for both itself and other emerging and developing economies, Brazil later proposed the Clean Development Mechanism (CDM), now enshrined in Article 12 of the Kyoto Protocol. The CDM has been an innovative financial mechanism by which Non-Annex I countries (generally developing countries) are allowed to host projects that reduce greenhouse gas (GHG) emissions, whereas Annex I countries (generally the advanced economies) may purchase these certified emissions reductions in order to comply with their emissions-reduction commitments under the Kyoto Protocol. Already, Brazil alone has initiated more than 300 CDM projects.¹⁸⁰

Granted, the Kyoto Protocol is due to expire in 2012, and given the failures to produce a global agreement on its substitute regime, its future — along with Brazil's successful CDM — is clouded in doubt. Nevertheless, the CDM has been one the key origins of the global carbon markets, however underdeveloped and fragmented they may remain. Furthermore, Brazil has actively continued to

¹⁷⁹ There is much potential for Brazil to develop shale gas, or even to import shale gas or GTL synfuels, from Argentina. The possibility for deeper energy integration to revive the moribund Mercosur customs union is beyond the scope of this study, but it should be explored.

¹⁸⁰ See Christophe de Gouvello, et al., *Brazil Low-carbon: A Country Case Study*, World Bank, 2010.

engage the international dialogue on climate change. In 2007, the Secretariat for Climate was created within the Brazilian Ministry of the Environment, and the following year, President Lula da Silva launched the National Plan on Climate Change (PNMC), defining the issue as a top national priority while clearly maintaining that actions to avoid future GHG emissions should not adversely affect the development rights of the poor. Brazil has since maintained such a posture with respect to both its own people and those across the developing world — the majority of the world’s population who have done little to generate the climate change problem except through clear actions of self-defense (i.e., deforestation to burn firewood).

For example, at the Copenhagen conference in December 2009, in addition to committing itself, as a Non-Annex I country, to significant voluntary emissions reductions against a business-as-usual trajectory, Brazil also made clear that it would consider collaborating, through cooperation and finance, with other developing countries in their low-carbon energy efforts. Brazil’s biofuels collaboration with the United States in the Caribbean and with countries all along the western littoral of Africa lends strategic credence to such commitments. Furthermore, in the aftermath of Copenhagen, the Brazilian Parliament adopted Law 12.187, instituting the National Climate Change Policy of Brazil, which set a voluntary national GHG emissions reduction target of between 36.1 percent and 38.9 percent of projected “baseline” emissions by 2020, effectively enshrining the country’s Copenhagen commitments into national legislation.

In addition, despite some recent setbacks, Brazil has also implemented innovative policies to reduce emissions from deforestation, land use, and land-use changes (global emissions sources known internationally by the acronym LULUCF), which currently account for about 20 percent of global GHG emissions, but which nevertheless represent the large majority of Brazilian emissions. Secondly, as mentioned above, Brazil has developed unprecedented experience in renewable energy, particularly bioenergy and hydropower, and as a result, Brazil’s per capita GHG emissions are 17 percent lower than they otherwise would have been, and significantly lower than those in other countries.

Given Brazil's centrality in the nascent Atlantic Basin energy system, and its weight as a global emissions generator now and in the future, it is hard to envision a resolution of the climate change challenge without key leadership and progress from Brazil. According to the IPCC, just to prevent the global mean temperature from rising higher than 3 degrees Celsius (as opposed to 2 degrees, still the agreed international target), atmospheric GHG concentrations must be stabilized at 550 ppm. By 2030, this will require all countries to reduce annual global emissions from 60 GtCO₂e to less than 30 GtCO₂e by then. At the same time, advanced economies' emissions are expected to stabilize only at around 22 GtCO₂e annually, with the rest of the world responsible for the remaining 38 GtCO₂e. Therefore, it is clear that advanced economies alone cannot sufficiently reduce their emissions further to stabilize global GHG concentrations below even 550 ppm. Significant reductions will have to come from the developing countries as well, because many more of the easiest and cheapest reductions have already been made by the advanced economies. As a recent World Bank study concludes: "Without Brazil playing a prominent role, it is difficult to envisage an effective solution at the global level, given its importance in setting political agendas."¹⁸¹ In this regard, only China is more critical than Brazil within the developing world.

The potential benefits for Brazil (and its southern Atlantic partners) of embracing and pursuing a serious leadership role in energy and climate change are enormous. A long-term low-carbon strategy would also generate significant development co-benefits. The World Bank study claims these range "from reduced congestion and air pollution in urban transport to better waste management, jobs creation, and costs savings for industry, and biodiversity conservation." The study concludes: "Countries that pursue low-carbon development are more likely to benefit from strategic and competitive advantages, such as the transfer of financial resources through the carbon market, new international financing instruments, and access to emerging global markets for low-carbon products. In the future, this may create a competitive advantage for the production of goods and services, due to the lower emission

¹⁸¹ Ibid.

indexes associated with the life cycle of products.”¹⁸² Continued success in rolling out renewable energies would make Brazil the hub of a nascent southern Atlantic renewable energy space, with the potential to develop strong renewables manufacturing sectors in the future.¹⁸³

3.2 The Gods Must Be Crazy: South Africa, Energy, and the Atlantic Basin

The Republic of South Africa is one of the most interesting national players upon the emerging energy landscape of the southern Atlantic. In striking contrast to the many oil producers ringing the African littoral of the basin (from Angola and Gabon to Equatorial Guinea and Nigeria, moving along the West African Transform Margin all the way to Guinea), South Africa has few significant upstream hydrocarbon resources. The country is largely dependent on imports of oil and natural gas, particularly for end use as vehicle fuel in the transportation sector.

In the realm of oil — the thin wedge of the country’s primary energy mix, associated primarily with transportation — South Africa bears more in common with its neighbors in East Africa up the Indian Ocean coast than with its West African neighbors of the continent’s Atlantic littoral. According to *Oil and Gas Journal (O&GJ)*, South Africa itself had proven oil reserves of a mere 15 million barrels in January of 2010, all of which are located offshore from southern South Africa in the Bredasdorp basin (west of Mossel Bay) and off the west coast of the country near the border with Namibia.

From these tiny reserves, South Africa produces about 35,000 bbl/d of domestic crude oil. With current annual consumption levels around 550,000 bbl/d, however, South Africa faces a supply gap of over half a million barrels per day of crude oil (or its refined product equivalent). Nevertheless, some 160,000 bbl/d of synthetic fuels are processed domestically from coal (CTL) and gas (GTL),

¹⁸² Ibid.

¹⁸³ For a more recent assessment of the role of Brazil (and Latin America and the Caribbean, in general) in the global climate change landscape, and of the potential for sustainable development co-benefits from adaptation and mitigation investments in the region, see Walter Vergara, et al, “The Climate and Development Challenge for Latin America and the Caribbean: Options for Climate-Resilient, Low-Carbon Development,” Inter-American Development Bank, Washington, DC, June 2012.

meeting about one-third of the country's total annual oil demand. That leaves approximately 380,000 bbl/d (or two-thirds of total demand) to be imported from the Persian Gulf and West Africa.

PetroSA (South Africa's state-owned national oil and gas company) is attempting to attract exploration investment in the hope of producing significant discoveries of oil.¹⁸⁴ In the meantime, however, the country will have to rely on either imports or greater domestic production of synthetic fuels. With such a high oil-import-dependence ratio (67 percent), South Africa has also, with time, diversified its import sources away from the geographically convenient, but politically volatile, Middle East area toward the Atlantic Coast of Africa and, in an incipient manner, the Atlantic littoral of South America.¹⁸⁵ South African oil imports are currently dominated by Saudi Arabia and Iran, followed by Nigeria and Angola. Imports from Angola in particular have surged in recent years, reaching about 20 percent of the total.¹⁸⁶

Without an upstream to speak of (at least not yet), South Africa's downstream becomes an even more strategic segment of its market. According to a report from the South Africa Petroleum Industry Association (SAPIA), South Africa had refining capacity of 703,000 bbl/d in 2010, the second-largest in Africa, surpassed only by Egypt (726,250 bbl/d, according to *O&GJ*). This capacity is spread across four conventional petroleum crude refineries and two synthetic fuels refineries (including Sasol's Secunda near Sasolburg and PetroSA's Mossel Bay facility on the coast of the Western Cape, see Figure 25).

¹⁸⁴ Petroleum Oil and Gas Corporation of South Africa (PetroSA) is responsible for managing and promoting the licensing of oil and natural gas exploration in the country and has exploration and production activities around the world.

¹⁸⁵ South Africa does import small amounts of oil from Venezuela and might, sometime over the next ten years, import oil from Brazil.

¹⁸⁶ South Africa also imports a small quantity of refined petroleum products such as gasoline and diesel, but it is still self-sufficient in kerosene for jet fuel and illuminating residences (mainly because the required specifications in South Africa make it somewhat difficult to import kerosene). Previously, this imported product came from Singapore, but given the significant expansion of refinery capacity experienced recently by India, it is now increasingly imported to South Africa from that country. Although South Africa has balanced its dependent links to the Indian Ocean and Atlantic Basins in its importation of crude, this new if still insignificant external dependence on imported product links South Africa exclusively with the Indian Ocean.

Figure 25. Refinery Capacity, South Africa, 1992–2010 (bbl/day)

Refineries	1992	1997	2007	2009	2010
Sapref	120,000	165,000	180,000	180,000	180,000
Enref	70,000	105,000	125,000	125,000	120,000
Chevref	100,000	100,000	100,000	100,000	100,000
Natref	78,000	86,000	108,000	108,000	108,000
Sasol	150,000*	150,000*	150,000	150,000	150,000
PetroSA	45,000*	45,000*	45,000	45,000	45,000
Total	513,000	651,000	708,000	708,000	703,000

*Crude equivalent.

These capacity figures have increased only marginally in the last 15 years. Sapref (a 50–50 joint venture between Shell and BP) increased capacity from 165,000 bbl/d in the mid-1990s to 180,000 bbl/d in 2010, and Natref (64 percent owned by Sasol and 36 percent owned by Total) increased capacity during the same period from 86,000 bbl/d to the current 108,000 bbl/d. Meanwhile, Enref (owned by Engen) has expanded capacity from 105,000 bbl/d to 120,000 bbl/d. Chevref in Cape Town (owned by Chevron) has maintained its capacity at 100,000 bbl/d, as has Sasol at its coal-to-liquids plant (still at 150,000 bbl/d, although it is planning an expansion of another 20,000 bbl/d capacity). On the other hand, PetroSA’s gas-to-liquids facility at Mossel Bay has experienced a decline to 32,000 bbl/d from 45,000 bbl/d, as a lack of available gas has forced the company to shut down one of the trains and leave only two operating, at least for the moment.

With South African demand for gasoline (1 percent to 2 percent annual growth), diesel (4 percent to 5 percent), and jet fuel (3 percent) all rising, expansion of refinery capacity might be a good idea, and even more so given that almost all of South Africa’s refineries are running at more than 80 percent capacity.¹⁸⁷ South Africa has traditionally been “long” (or in surplus) in terms of domestically produced refined products, but rising demand and capacity constraints — including Engen’s temporary refinery

¹⁸⁷ Sasol’s Secunda coal-to-liquids plant is actually running at around 95 percent capacity. On the other hand, PetroSA’s Mossel Bay gas-to-liquids facility is running at only two-thirds capacity.

shutdown in 2010 — have begun to require net product imports (especially of high-octane varieties).¹⁸⁸

Nevertheless, PetroSA now plans to build a new large crude refinery with a capacity of 350,000 to 400,000 bbl/d in Coega, near Port Elizabeth in the Eastern Cape, south of Durban.¹⁸⁹ But Project Mthombo (the Xhosa word for “spring” or “source”) is at least facing some obstacles. The projected required capital costs amount to more than \$11 billion — too much for PetroSA or the South African government to carry or back alone. As a result, the government has instructed PetroSA to find one or more anchor partners; however, not many interested parties have presented themselves other than Sonangal, Sinopec, and PETRONAS. Given the current overhang in global refinery capacity, a natural reticence has checked capacity expansion and made downstream investors cautious. Furthermore, Petro SA is not in a financial position to offer very attractive terms to non-South African actors.

Sonangol, the state-owned national oil and gas company of neighboring Angola, has made overtures of potential downstream collaboration with PetroSA on its Coega project. But it has also suggested that PetroSA partner with it on a projected 250,000 bbl/d capacity refinery at Lobito on the central coast of Angola. The original *raison d'être* of the projected Lobito facility was to generate gasoline for export to the United States and diesel for export to Europe. PetroSA would obviously prefer for Sonangol to invest in a facility in South Africa that is producing product for the growing, and increasingly capacity-constrained, South African transportation market.

The Chinese have also stepped into this Southern African corner of the downstream market, offering to help Angola finance its Lobito project; but their terms were apparently not sufficient for the Angolans, as this possibility seems to have receded. Also, given the change in demand patterns in the United States (which in recent years has experienced a slight decline in gasoline demand), the

¹⁸⁸ South Africa converted to 100 percent unleaded gasoline in 2006. However, most of the actors in the South African downstream opted for capacity expansions that would not require extremely high initial CAPEX (as would be the case for expansion of high-octane capacity). As a result, South Africa is now importing to meet much of its high-octane demand.

¹⁸⁹ Refinery data comes from SAPIA, the EIA, and an interview with David Wright of Engen in Cape Town.

United States is now actually exporting refined product into the Atlantic Basin. Under such conditions, there is a stronger logic for Angolan–South African (and even Chinese) collaboration in the downstream to take the form of capacity expansion in South Africa rather than the expansion of export capacity oriented to a vanishing U.S. market for Atlantic Basin imports, based out of a shared refinery in Angola.¹⁹⁰

South Africa is also an outlier within the southern Atlantic context in another sense: it lacks abundant hydroelectric potential. Indeed, South Africa currently is a net importer of (an admittedly small amount of) hydro-generated electricity from its neighbors in the Southern African Power Pool (where the potential output is far greater in relation to demand). Furthermore, modern renewable energies (such as solar PV, concentrated solar, and wind power) currently provide only token quantities — from a mere 4MW of installed wind power capacity — to South Africa’s energy mix.¹⁹¹

On the other hand, South Africa is powerful player in the troubled realm of coal. Abundant, cheap, low- to mid-grade coal has traditionally provided the economic foundation for South Africa’s powerful mining and industrial complexes. With approximately 4 percent of estimated global coal reserves, the country is a major producer, consumer, and exporter of coal. In terms of its energy consumption, South Africa is more dependent on coal than is any other country in the world — including China, well known for the centrality of coal in its primary energy mix — with coal

¹⁹⁰ The Atlantic Basin refined product balance (gasoline and diesel) has been traditionally maintained by a particular pattern of trade: Europe’s excess diesel demand was met by Russian crude and U.S. exports of diesel, and European surplus gasoline was exported to the United States. However, this pattern has changed since 2008, when U.S. gasoline demand began to decline. In this new pattern, even European refined gasoline is looking for a market in the Atlantic Basin, with much going to Nigeria, where insufficient maintenance converts a country that is theoretically capable of refining its own petroleum products for internal consumption and exporting to the world into a net importer of product.

¹⁹¹ This situation is changing, however. See the sub-section on South Africa in section 2.5.5, Renewable Energy in the Atlantic Basin.

contributing nearly 75 percent and 90 percent, respectively, to South Africa's energy and electricity matrices.¹⁹²

However, as greenhouse gas emissions have become a sensitive political issue in recent years, the South African coal sector has begun to face increasingly demanding environmental constraints, as have other sectors linked to coal (such as electricity, industry, and mining), with pressure mounting to either reduce its CO₂ emissions or scale back production and consumption of its heavy, and dirty, industrial output. South Africa releases more than 440 million tons of CO₂ every year (up from 316 million tons in 1995), accounting for 80 percent of the country's total greenhouse gas emissions. Furthermore, 80 percent of the country's CO₂ emissions are generated by the energy sector (compared with 9 percent released in agriculture, 8 percent from industrial processes, and 7 percent from waste).

Such an emissions profile makes South Africa an outlier in still another way. Energy-related emissions of CO₂ in South Africa account for four-fifths of all greenhouse gas emissions, whereas in some advanced countries they account for under half, and in many developing countries, less than a quarter. Not only, then, is South Africa's energy mix skewed to an unusual extent toward coal, but also its emissions profile is ominously dominated by the country's cheapest and most abundant resource, putting coal at the heart of a Gordian knot wrapped around the South African energy sector.

Coal has long been the backbone of the South African economy, providing upwards of three-quarters of the country's primary

¹⁹² Nearly three-quarters (72 percent) of all the energy consumed in South Africa (1 percent of global primary energy consumption) has coal as its primary source. Oil is — at a huge distance — the second-most important primary energy source in South Africa, contributing approximately 13 percent to the mix. Combustible renewables (firewood, or traditional biomass) and waste account for just over 10 percent. Natural gas (2.8 percent), nuclear power (2.2 percent), hydroelectricity (0.1 percent), and modern renewable energies such as wind and solar power (negligible) provide tiny shares to the primary energy mix. See EIA Country Analysis Brief, South Africa, March 2010; IEA, Energy Balances for South Africa, 2007 (http://www.iea.org/stats/balancetable.asp?COUNTRY_CODE=ZA); BP, Statistical Review of World Energy, June 2011. Note: The EIA and the IEA include both modern renewable and combustible renewable and waste (CRW, consisting of firewood and traditional biomass) in their calculations of the South African energy mix. Because the BP figures do not include the traditional CRW forms of biomass, all the other categories of primary energy increase their shares to some degree in the calculation according to BP figures — particularly petroleum, which, according to BP, contributed 20 percent of the country's primary energy mix in 2010. According to the International Energy Agency (IEA), in 2007 South Africa consumed an equivalent of 5.3 quadrillion Btu (of nearly 550 quadrillion Btu equivalent consumed globally each year at the time).

energy. Coal fires all of Eskom's baseload generation plants (except for a single nuclear plant), burns in the furnaces of metallurgical companies, and serves as a major feedstock for Sasol's energy and chemical products.

At the end of 2010, South African coal reserves were estimated to be approximately 30 billion tons, accounting for more than 90 percent percent of African coal reserves and 3.5 percent of proven world reserves.¹⁹³ At the end of 2007, these figures had been as high as 34 billion tons, and 95 percent and 4 percent of African and world reserves, respectively. Yet, even while coal reserves were being drawn down in South Africa, coal's share in the energy mix was edging even higher. In 2007, coal provided for 72 percent of the primary energy mix and 85 percent of the electricity mix; in 2010, coal contributed to 73 percent of the primary mix and 90 percent of the generation capacity mix.¹⁹⁴

Production and consumption of coal have remained relatively stable over the past decade. In 2008, the country produced an estimated 260 million short tons (279 million short tons in 2010, or 253.8 million metric tons) and consumed 194 short tons. Eskom is by far the biggest consumer, burning some 120 million short tons a year in its coal-fired generation plants. A number of smaller municipal power producers burn an additional 6 million tons. Sasol takes on most of the rest of domestic consumption to produce its coal-to-liquids synthetic fuels.

The remaining 66 million short tons (or 72 million metric tons) produced by South Africa are currently exported. South Africa should be able to export about 100 million tons, given the 91 million tons of capacity for exports through the Richards Bay coal terminals, and residual export capacity at Maputo in neighboring Mozambique and other more minor terminals. Nevertheless, the country's rail transport capacity serving Richards Bay is currently less than 70 million tons.

Independent of what one might argue with respect to the apparent stagnation in South Africa's coal reserves, the country has recently

¹⁹³ BP's Statistical Review of World Energy 2011.

¹⁹⁴ See BP, EIA and South Africa's IRP 2010. Estimates by independent coal analysts in South Africa put current proven reserves at around 33 billion tons, roughly 4 percent of world reserves.

experienced a powerful shift in the flows and destinations of its coal exports. Traditionally, South Africa's higher-quality coal would be exported primarily to markets in the Atlantic Basin (mainly Europe). In 2007, South Africa sold 88 percent of its exported coal to Europe and other Atlantic markets. Since then, however, European demand has slumped due to recession, Asian demand has continued to rise, and Colombian supply has begun to satisfy much of the import demand in the Atlantic Basin. Currently, an increasing share of South Africa coal exports moves into the Indian Ocean Basin. By 2010, about 55 percent of coal exports went to Asia, only 25 percent went to the traditional Atlantic Basin markets, some 7 percent went to the Middle East, and a small amount went to South American and African countries in the southern Atlantic.

The Indians are the big new arrivals in South Africa's coal market.¹⁹⁵ They have the means to pay, and transport is relatively short and cheap. Although India's principal harbors are still too shallow for the typically large Cape shipments, the Indians are investing in deepening their ports. Recent shipments of South African coal to India (6000 kcal/kg gross) were being sold at \$126 per ton, a relatively high price for such a quality. As a result of the rapid ramp-up of Indian demand, combined with a recessionary slump in demand coming from the North Atlantic, U.S. and EU markets now look for cheaper, higher-quality coal elsewhere. Colombian coal (with an ash content of only 7 percent, compared with South Africa's average of between 20 percent and 25 percent) is now picking up most of the export trade into the Atlantic Basin.¹⁹⁶

The future of South African coal concerns a number of local actors in different ways. Although environmentalists and certain branches of the government are most concerned with CO₂ emissions from coal, the dominant electricity producer, Eskom, is more concerned

¹⁹⁵ India's share of South Africa's coal exports has risen from almost nothing five years ago to an average of 30 percent. South African coal is preferred by many Indian end-users in the sponge iron and cement sectors for its consistent quality, but because the market is so price-driven, consumers will switch quickly if delivered costs rise to unacceptable levels (*International Business Times*, February 10, 2011, <http://www.ibtimes.com/articles/111141/20110210/s-africa-coal-price-fall-draws-out-indian-buying.htm>).

¹⁹⁶ There also exists the possibility of transporting high-quality, low-sulfur seam coal by rail across the Kalahari Desert from Botswana to the Namibia's Atlantic Coast. A number of coal importers in the Atlantic Basin might be interested in such a prospect. Some estimate that Botswana has some 20 percent of the world's total coal "resources," although it is not yet clear what level of proven reserves Botswana might have.

with the apparent fall in national coal reserves and the increasing competition it faces from Asia (India, in particular) to procure local South African coal.

South African coal contains a relatively low energy content. The commercial pattern in South Africa traditionally has been to export the highest-grade local coal and to use the lower grades for Sasol's CTLs production and for Eskom's domestic electricity generation. For decades, this meant a kind of marriage of convenience between exporters of South African coal and local industry. Raw coal from the mine was moved to a separating plant (where high and low quality were separated, based on ash content, energy levels, gravity, densities, etc.), with the highest caloric and lowest ash content coal earmarked for export, and the rest of the "middling"-quality coal would typically be the best that Eskom might procure.

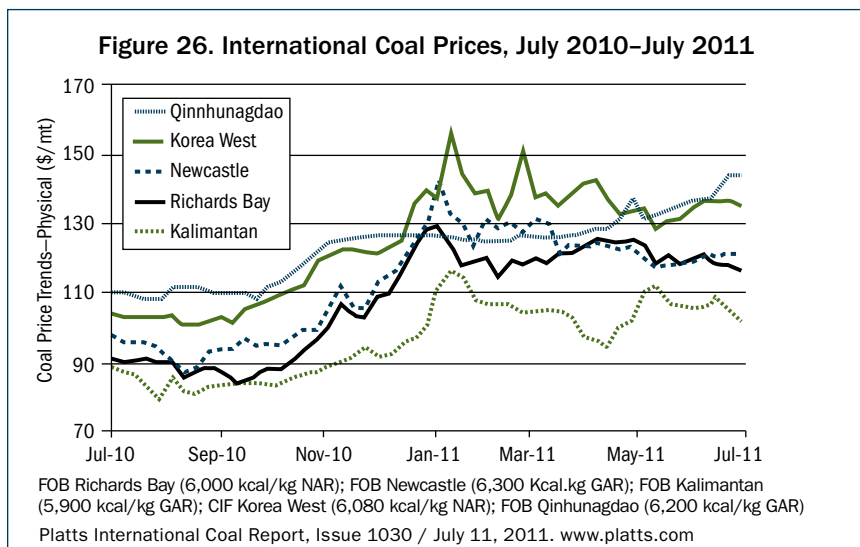
The export shift from Atlantic Basin to Indian Ocean, mentioned above, particularly to India, has implied exporting much larger quantities of lower-quality coal than had been typical of exports into the Atlantic Basin. At the same time, the quality of domestically burned coal is declining as well (for commercial and infrastructure reasons), placing Eskom procurement in indirect competition with exports to India.¹⁹⁷ Eskom has been experiencing some difficulties sourcing 5,700 kcal/kg coal. The standard quality of export coal would traditionally have been around 6,300 kcal/kg (or 26.5 megajoules per kg). Although China and Japan are still purchasing South African coal of 6,300 kcal/kg quality, many South African coal shipments are now as low as 5,700 kcal/kg in quality. Some South Africans even argue that there is no need to export coal that could be reserved for Eskom. Given export prices, however, such an allocation of resources would be of doubtful economic sense.

International coal prices have approximately tripled since 2003, tracking the price of oil — which has also roughly tripled —

¹⁹⁷ There has also been a universal decline in the quality of South African coal, along with a decline in the thermal efficiencies of Eskom's power plants, in part due to lack of sufficient rail infrastructure. South Africa's coal system is designed for rail transport, but currently there is insufficient capacity. Because thermal efficiencies of power plants fall if the coal quality cannot be anticipated or known with certainty (in such cases, much of the energy content of the coal does not burn), coal's efficiency declines when delivered in trucks by smaller independent suppliers, the quality of whose coal is typically harder to verify. Eskom's performance has been increasingly affected recently by lower-quality coal, which has been difficult to monitor (as has that of municipal power stations).

through the energy-price spike of mid-2008, the subsequent price collapse of late 2008 and early 2009, and the steady recovery and increase over the last year. The price for South Africa's coal (FOB Richards Bay 6,000 kcal/kg) peaked around \$130 per metric ton at the end of 2010, and remained in the range of \$110 to \$130 per metric ton during 2011.

Historically, South Africa's export prices have tended to move together with international prices, whereas its domestic price has tended to be more stable and much lower. However, this price wedge has changed dramatically in recent years, as the export trade has shifted away from the oversupplied and cheaper Atlantic Basin coal markets to the Indian Ocean basin, where China continues to provide strong demand for South Africa's higher-grade coal while India has placed an increasingly high demand on South Africa's mid-range coal, providing large domestic consumers of coal in South Africa, such as Eskom, with significant procurement competition. On the other hand, exporters are still squeezed to some degree by the constant mid-grade-quality competition from Indonesian coal.



Related to the issue of stagnant coal reserves and tighter commercial supplies in South Africa have been the indirect transitional effects of the Black Economic Empowerment (BEE) policy on the exploration, production, and efficiency of the coal-fired sectors (see also the section below on South Africa's BEE

policies). Under the 2002 Mining Law (MPRDA), BEE criteria entered the coal world. Indeed, the new legislation was intended to liberate and democratize the entire mining industry. Although the MPRDA has generated many opportunities, it has also created, in some cases, excessive hopes.

The most significant change the new law introduced was to limit private landowners' rights to the surface of the land, with the state assuming control of subsurface mineral rights. Previously, private owners had controlled both the surface *and* subsurface (along with the concomitant mineral rights) of their lands. In theory, the law gave black South Africans indirect access — through the state and its BEE policy — to the mineral wealth of the country.

Under apartheid, blacks were not allowed into the mining sector except as paid labor. Since 2002, however, blacks have been able to apply for mining licenses. However, many black-owned entities have lacked sufficient capital and knowledge to mine and produce coal efficiently. As a result of this extension of BEE into the coal mining business in South Africa, the sector has experienced increasing fragmentation and inefficiency, at least in relative terms, along with stagnant reserve levels.

The growing pains of the BEE policy in South Africa have tended to express themselves through weaker coal exploration and production, and a decline in the quality of coal reaching Eskom power stations. This may be a temporary, if inevitable, transition cost.

Sasol consumes nearly a third of the coal burned domestically in South Africa, using it as the major feedstock for the company's synthetic coal-to-liquids fuel production. At the Sasol synfuels plant in Secunda (near Sasolburg), around 45 million short tons of coal a year are converted into liquid fuels, gas, and other products. The plant itself produces an estimated 150,000 bbl/d of synthetic gasoline and diesel, and is the world's only commercial coal-to-liquids plant in operation.

Sasol has experienced much success during its 60-year life.¹⁹⁸ Now known as “an integrated energy and chemical company,” Sasol began its first CTL production, based on the Fischer-Tropsch

¹⁹⁸ See Petra Wessels, *Crescendo to Success: Sasol 1975–1987*.

process, at Sasolburg in 1955. In the early 1980s, the large dual-CTL facility at Secunda became operational. During the early 1990s, Sasol licensed its new gas-to-liquids technology to PetroSA for that firm's Mossel Bay GTL plant.

By the mid-1990s, Sasol was seeking to globalize by approaching natural gas and coal resource owners to form CTL and GTL joint-venture companies. Sasol now owns a stake in the Oryx GTL plant in Qatar that was commissioned in 2007. Sasol, PETRONAS, and Uzbekneftegaz have signed an agreement to establish a joint venture for developing the Uzbekistan GTL project. Sasol also has an economic interest in the Escravos GTL plant in Nigeria that was due to be commissioned in 2011, and is conducting feasibility studies relating to potential CTL plants in China and South Africa.

Sasol is cash rich and, as the country's single heaviest emitter, is lobbying against CO₂ controls, along with the Chemical and Allied Industries' Association. Still, due to intense pressures to cut CO₂ emissions, it will not be easy for Sasol to pursue building additional CTL plants — at least in South Africa — unless it invests heavily in carbon capture and sequestration (CCS) technology. On the other hand, Sasol could also invest in a future based on natural gas and GTL production (see the sections below on Natural Gas and GTL). Whether or not these represent mutually exclusive strategic options is a decision to be made by the South African government.

Although carbon capture and sequestration technology suffers little from the kinds of immediate controversies plaguing shale gas production, neither is its widespread commercial application an immediate prospect. Given South Africa's extreme dependence on coal, however, a robust CCS strategy with a clear regulatory and investment roadmap would be very convenient.

Despite recognized CCS potential in South Africa, its future could be circumscribed by both geological and market uncertainties. For example, the "Long-Term Mitigation Scenarios" (LTMS) — South Africa's central strategic climate document, developed in 2007 by the then Department of Environmental Affairs and Tourism (DEAT) — projected CCS to contribute only around 5 percent of the country's projected emissions reductions, a relatively low finding reflecting 1) a limited geological potential for safe, permanent storage within the country, and 2) the high level of

uncertainly still associated with the application of CCS technology in the world in general and in South Africa in particular.

Nevertheless, having committed the country to a significant reduction in CO₂ emissions, in 2009, the South African government established the South African Centre for Carbon Capture and Storage (SACCCS) to investigate the feasibility of CCS in South Africa and to establish a practical roadmap for the first full-scale commercial CCS deployment in South Africa by 2025.

In 2010, the Centre produced a CO₂ storage atlas that projected 150 gigatons of storage potential in South Africa — or enough to capture and store all of the country's current annual CO₂ emissions for 375 years.¹⁹⁹ Although this figure is of an entirely different, and much larger, magnitude — compared to the estimate of CCS' potential in the LTMS of three years earlier — it has pushed the Centre to develop a roadmap for the commercialization of CCS technology in South Africa.

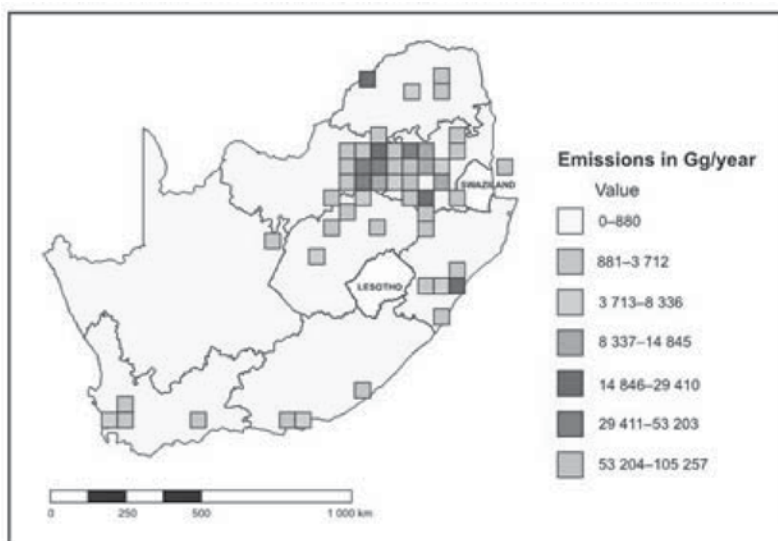
Currently, the Centre is engaged in pursuing this roadmap through:

- initial studies on CCS potential in South Africa (2004, completed);
- Carbon Storage Atlas (2009, completed);
- test injection (2016, planned, 10,000s tons);
- demo plant (2020, planned, 100,000s tons); and
- first full-scale commercial plant (2025, planned, millions of tons).

A regulatory system for CCS does not yet exist in South Africa. However, the regulatory regime for the extraction of minerals is well developed, and the administration of such regulation falls under the authority of the Department of Mineral Resources and its regional offices. An investigation into the regulatory gaps pertaining to CCS was begun by the DOE in 2009.

¹⁹⁹ See the Centre's Atlas on Geological Storage of Carbon Dioxide in South Africa (2010).

Figure 27. Emissions, Geographic Concentrations, South Africa, 2010



Source: Atlas of Geological Storage of Carbon Dioxide in South Africa, 2010

Given the overwhelming centrality of coal in the country's energy economy, the extremely wide range between initial and more recent estimates of South Africa's CCS potential presents energy policymakers with a dilemma between planning for the LTMS' more modest projection and planning for wide-scale commercial application. Much will depend on international trends in CCS research and application, particularly in the United States, China, and Europe, the current global leaders in CCS technology and investment. What is clear, however, is that the future of South African coal dependency is at stake. Under one scenario, coal could remain king in South Africa; under the other, coal would gradually be phased out of the country's energy mix.

Beyond the potential to exploit CCS technology, the South Africa coal sector also has the potential to apply other types of "clean coal" technology. Increasing the combustion efficiency of its coal-fired power plants would offer the South Africa "minerals-energy complex" the possibility of reducing its current emissions to a large degree without having to engage in direct "energy switching" (say, from coal to gas). A number of players on the South African coal scene claim that simply enhancing the combustion parameters at power plants would significantly reduce CO₂ emissions. This is

because the thermal combustion efficiency of South African power plants is only 36 percent, compared to average thermal efficiencies of 45 percent in Europe. By applying state-of-the-art technology, South African power plants would be able to burn raw coal more completely, allowing less CO₂ and solid particulate pollution to be released into the atmosphere.

Eskom is currently considering retrofitting its existing power plants to improve efficiencies and reduce emissions. Furthermore, the two new power stations that the company currently has under construction will have thermal efficiencies close to their European counterparts. In addition, South Africa participates in the IEA's Clean Coal Science program and is presently developing a new coal roadmap in which clean coal and CCS are bound to figure prominently.

3.2.4 The Promise of Synfuels: Coal-to-liquids and Gas-to-liquids

For nearly 50 years now, South Africa has pioneered the realm of synthetic fuels (synfuels), first through the use of coal-to-liquids (CTL) technology and later through a related gas-to-liquids (GTL) process. With the world's only commercial CTL plant and its second-largest commercial GTL plant, South Africa could be well placed to help spur significant change in the energy landscape of the Atlantic Basin.²⁰⁰ Should the shale gas revolution spread to the Southern Cone (where Argentina is estimated to possess the world's third-largest reserves of this unconventional gas), a regional expansion of South Africa's GTL transportation fuel technology would then be a feasible scenario (possibly even without the exploitation of the Karoo's shale gas; see the section below on Shale Gas). Such a development would be of major global significance, with the potential to transform the energy and economic relationships of countries on both sides of the Atlantic Basin, particularly in the southern Atlantic.

In addition to PetroSA's planned conventional crude refinery buildup, there are other options available in the downstream to

²⁰⁰ For years, South Africa's Mossel Bay GTL plant, with production over 30,000bd, was the world's largest commercial GTL plant — in effect, the pioneer, along with Sasol. Shell's recently inaugurated Pearl GTL plant in Qatar is now larger. However, Sasol is now involved in projects using its technology in both the Middle East and the Atlantic Basin. See the subsection on GTL in section 2.4.3 on the Downstream.

meet South Africa's rising fuel demand, and some of them have been taken up and pushed ahead. For example, Sasol, the formerly state-owned "fossil fuel" and chemical company (it calls itself an "integrated energy and chemical company"), is planning an expansion of its cutting-edge synthetic fuel capacity based on a descendent of the Fischer-Tropsch coal-to-liquids technology pioneered by the Germans during World War II.

Currently Sasol operates the world's only commercial coal-to-liquids synthetic fuels facility at two sites in Secunda near Sasolburg. Then state-owned Sasol began its earliest CTLs production in 1954 and invested heavily in the large Secunda facility in the early 1980s — in part as a response to the oil crises of the 1970s. In the wake of the long energy crises of the past decade, Sasol has floated plans to build a new CTLs plant northwest of Pretoria, harnessing a new Sasol technology for producing diesel from coal. Project Mafutha (the Zulu word for "fat" or "oil") has a planned capacity of 80,000 bbl/d of diesel output.²⁰¹

The synfuel option may seem clear to many, but Sasol's CTL technology faces some significant obstacles — as does PetroSA's related GTLs process. Not only are the capital costs of synfuel plants more than twice those of crude refineries, but also synfuels may produce higher life-cycle CO₂ emissions than do petroleum-based gasoline and diesel (although the comparative advantage in terms of particulate, sulphur dioxide, nitrous dioxide, and other emissions, are clear. See the subsection on GTL in the section on the Downstream). The only strategic option available to South Africa in this regard, considering the ever-tightening emissions constraint, would be focus on the expansion of synfuels production from gas — not coal — based on Sasol's GTL technology. GTL production emits far less CO₂ than does CTL, and its end-use consumption in vehicles could emit far less than do petroleum-based gasoline and diesel fuels if further innovation can reduce life-cycle emissions (for example, applying at least some carbon capture to the GTL process).

PetroSA manages what has been the world's pioneer commercial natural gas-to-liquids (GTL) plant at Mossel Bay in the Western

²⁰¹ The combination of downstream capacity expansion plans at PetroSA (Coega) and Sasol (at its CTL plant northwest of Pretoria) could potentially bring South Africa's domestic fuels production (refinery) capacity to more than 1 million bbl/d.

Cape, with a total maximum capacity of 45,000 bbl/d. Through PetroSA, South Africa could explore the strategic benefits of a major national push in GTLs technology and production. Sasol, too, might consider the benefits of converting its Secunda facility to GTLs, or of building much or all of new capacity at the margin using GTLs technology (a technical cousin of CTLs). According to the Department of Minerals and Energy, more than one-third of liquid fuel demand in South Africa is already being met by synthetic fuels. There is currently room to displace upwards of 400,000 bbl/d of crude oil imports with new cleaner GTLs production, and this potential domestic market (to say nothing of a potential global market in the future, should the shale gas revolution succeed) grow in the future as more South Africans drive more automobile kilometers in the emerging South African economy.

Whereas the primary obstacle facing CTLs expansion is the greenhouse gas emissions constraint, the problem facing a GTLs expansion is even more fundamental: a basic shortage of gas in South Africa. Historically, South Africa has never had much gas, and readily available supplies for South Africa have been declining in recent years. As a result, the potential for GTLs technology either to increase security of supply in the South African downstream (through GTLs production to replace oil imports) or to reduce the country's carbon emissions (through a gradual substitution of both coal and petroleum in the transportation sector) depends heavily on the future of natural gas in South Africa.

South Africa has even less natural gas than it does petroleum, and ever since PetroSA began production at its Mossel Bay GTLs facility, the country's minimal proven reserves of natural gas have dwindled to the point of near exhaustion.²⁰² According to the EIA, in 2008, South Africa produced 115 billion cubic feet (Bcf)

²⁰² According to Cedigaz (quoted in the EIA South Africa Country Brief), South Africa had 0.32 billion cubic feet (Bcf) of proven natural gas reserves in 2009, the equivalent of only 60,000 bbl of oil. According to CIA Factbook (quoted at http://www.indexmundi.com/south_africa/natural_gas_proved_reserves.html), South Africa had 27.2 million cubic meters of proven reserves of natural gas in 2006 — the equivalent of 178,000 bbl of oil, in theory, only a week's GTLs production at current levels — and was 98th in the national ranking of proven natural gas reserves. South Africa gas reserves are too small to figure in BP's Statistical Review of World Energy. Whatever the actual figure of South Africa's dwindling reserve, this does explain why PetroSA has suspended operations of one of its three GTLs trains at Mossel Bay (bringing production down from 45,000 bbl/d to 35,000 bb/d) and has begun to rely on the use of condensate and natural gas imported via Sasol's pipeline from Mozambique to run its two trains ++currently still in operation.

of natural gas and consumed 228 Bcf. The remaining 113 Bcf (essentially 50 percent of domestic demand) was being imported principally from neighboring Mozambique.

Almost all of South Africa's imports of natural gas (some 113 Bcf, or 3.2 Bcm, annually) come from Sasol-controlled gas fields in Mozambique (Pande and Temane) and are transported to the Johannesburg, Pretoria, and Durban industrial zones through a 535-mile transport pipeline, which Sasol, the South African government, and the government of Mozambique own through a joint venture. The Mozambique gas pipeline (one of the centerpieces of a \$1.2 billion natural gas project begun by South Africa in 2004) has a peak capacity of 524 MMcf/d (or 191 Bcf annually) of natural gas. Although the pipeline still has a capacity utilization rate of no higher than 50 percent, it has been designed to eventually double its current capacity, in anticipation of increased gas imports from Sasol fields in Mozambique and, eventually, Tanzania. The bulk of this imported gas from Mozambique has been going to Sasol (either to be used as a GTL feedstock or to be sold through South Africa's limited domestic gas pipeline system to steel makers, some industrial users, and a limited number of households) and to PetroSA's GTLs plant at Mossel Bay.²⁰³

The South African government, along with PetroSA, is now hard pressed to discover new natural gas reserves in order to extend the lifespan of its Mossel Bay GTLs plant, now in danger of shutdown due to an increasing shortage of gas. Although successful exploration has taken place in Mossel Bay, PetroSA has claimed that production from its new Jabulani and Ihubhesi fields would not come on line until 2012 and 2013, at the earliest. In the meantime, the GTLs plant is relying on an increasing amount of condensate in its feedstock mix, but domestic supplies of condensate are also likely to soon go into decline.

Although gas appears to be running out in South Africa for supplying sufficient feedstock to keep the pioneer Mossel Bay GTLs facility functioning over the middle and long run, there are

²⁰³ PetroSA's gas to liquids (GTLs) refinery at Mossel Bay began operations in 2004 and is one of the largest in the world. It employs a Fischer-Tropsch process in which natural gas is converted to synthetic liquid fuels. The refinery has the capacity to process 45,000 bbl/d of oil equivalent, but currently the facility is running at two-thirds capacity. Mossel Bay utilizes gas and an increasing amount of condensate as feedstocks, maintaining output at around 35,000 bbl/d.

some promising offshore gas fields along South Africa's Atlantic coast near the border with Namibia. Namibia's own Kudu gas field is also a potential source of gas or of gas-generated electricity to be imported by international interconnection, in the case that a combined-cycle gas turbine (CCGT) plant were to be built in Namibia near the gas field, instead of constructing a gas pipeline into South Africa. Furthermore, Sasol appears to be eyeing more gas deposits farther afield, particularly offshore in southern Tanzania (from where gas might be sent by pipeline to South Africa sometime in the future).²⁰⁴

Much is at stake for South Africa in this search for new sources of gas. Most immediately, without new gas (and given the costs and uncertainty of a future dependent on LNG imports), the fate of PetroSA's Mossel Bay plant is in question. More strategically, however, without new gas, any long-term strategy to push Sasol GTLs technology worldwide will be very difficult — financially and technically — to sustain. Nevertheless, at the moment, South Africa is the world's leading actor at the development frontier of synthetic fuels, particularly gas-to-liquids. Sasol is one of only a small number of companies (Shell, Statoil, and ExxonMobil are the others) that possess GTL technology that has been proven to work at a commercial scale. Sasol produces a small amount of GTL output at its original 1954 CTLs plant at Sasolburg, and licensed its technology to PetroSA for use at South Africa's showcase GTL plant at Mossel Bay.

If a gas revolution around GTLs is to be embraced by South African energy strategy, it will need to be underpinned by a long-term Sasol strategy centered on finding more gas, rolling out GTL technology at home to displace coal and oil in the domestic energy mix, and investing globally in GTL projects in strategic locations. Already Sasol is involved in GTL production in Qatar (at the new 34,000 bbl/d Oryx GTL facility), and it has a stake in Nigeria's Escravos

²⁰⁴ Plans to construct a South African national gas ring linking the country's Atlantic and Indian Ocean sources are also under consideration, but not much progress appears to have been made to that end.

GTL project. Sasol also has been exploring the possibility of GTL investment in gas-rich Uzbekistan.²⁰⁵

Either South Africa comes up with a viable source of imported or domestically produced gas, or PetroSA's cutting-edge GTL facility will face a grim future and the share of natural gas in the primary energy mix — already negligible at 2.8 percent — will fall to further irrelevant levels. Interestingly, the key actors in the future of South African gas are Sasol (the powerful "fossil fuels" and chemicals company) and Eskom (the electricity producer, still a state-owned monopoly and heavily based on low- to mid-grade coal used to fire conventional thermal generation plants).

In Sasol's case, the variables pressing it to increase South African gas supply are multiple. First, Sasol faces an increasingly stringent emissions constraint (at least informally). Traditionally, most of Sasol's activities were linked to, or based on, coal. But because coal will eventually have to be phased out (due to its significant CO₂ emissions), Sasol has a motive not only to discover and/or come into partnered control of as many gas fields (and as close to home) as possible, but also to base its future activity increasingly on gas, as opposed to coal.

Secondly, although imports of liquefied natural gas (LNG) remain an option for Sasol (and for PetroSA), the LNG market is currently characterized by a high level of uncertainty with regard to future supply and demand balances, levels of required investment and, most importantly, future price levels. The high levels of risk implied in an LNG strategy make international upstream investment a more attractive option for Sasol, particularly if it can be made in friendly neighboring East African countries, such as Mozambique and Tanzania, through which pipeline expansion in the future is a feasible economic and political prospect.²⁰⁶

²⁰⁵ In September 2011, Sasol and its partners signed an investment agreement with the government of Uzbekistan for the development and implementation of a gas-to-liquids (GTL) project in which Sasol and local state-owned oil and gas firm Uzbekneftegaz each hold 44.5 percent interest, and Malaysia's PETRONAS an 11 percent interest. See "Uzbek Gas-To-Liquids Project Milestone for Sasol," *All Africa*, September 28, 2011, <http://allafrica.com/stories/201109280640.html>.

²⁰⁶ Although plans have been made to import LNG for the Mossel Bay GTLs refinery in order to meet the plant's natural gas requirements until PetroSA's new fields come on line, South Africa still has not imported any LNG. NERSA, the South African energy regulator, has even turned down a number of LNG import applications as inadequate.

The third variable informing a new Sasol gas strategy is the potential for large amounts of shale gas to be produced in the Karoo Basin. Should South Africa turn out to possess significant unconventional gas reserves in the shale formations of the Karoo, Sasol would have a great interest in developing them, as they would make increasingly expensive and unstable imports less necessary, and South Africa's synfuel strategy could be deepened. Indeed, Sasol has applied for exploration rights (along with Shell) in the Karoo.

Eskom, the large state-owned electricity monopoly, also has much at stake (although its interests are more complex) in the future direction of South African gas. Natural gas currently plays a very limited role in the South African electricity sector, but the government plans to increase gas imports and expand domestic gas production, which would diversify the energy mix and offset some of the country's excessive overreliance on coal. Eskom would be directly affected: Like Sasol, it would be the key executor of any significant switch from coal to gas. Eskom's interests dovetail very closely with those of Sasol with respect to gas supply (and the shale gas of Karoo, in particular). Because Eskom's credit strength has been questioned in recent years, and because the South African rand appears to be in long-term decline against the dollar and the euro, the company would clearly prefer domestic to imported gas priced in dollars. More piped imports from Mozambique and Tanzania would be a "second best" for Eskom.

More Sasol gas discoveries in East Africa and more clearly gas-oriented strategies from Sasol and Eskom would certainly help, but the future of South African gas — and its strategic GTLs subsector — essentially hinges on the global shale gas revolution currently under way, and on the potential shale sources of South Africa's Karoo Basin.

3.2.6 Shale Gas

Shale gas could be a game changer on the energy scene in South Africa — *if* the shale formations of the Karoo Basin indeed trap significant amounts of gas, and *if* powerful incipient environmental and local resistance can be overcome. Some South Africans doubt the Karoo holds much gas; even PetroSA has stated that it does not know how large the country's shale gas reserves might be. However, drilling by the former state-owned South African oil and

gas company Soekor has proven the existence of shale gas in the Karoo. Initial estimates in South Africa had put shale gas reserves at 30 trillion to 40 trillion cubic feet, but a recent EIA study of international shale gas resources suggests that South Africa's Karoo Basin guards the world's fifth-largest reserves of shale gas (some 485 tcf), behind China, the United States, Argentina, and Mexico, accounting for a whopping 8.4 percent of total estimated global shale gas reserves.²⁰⁷

Exploration rights have been awarded by South Africa to a number of oil and gas companies to study the potential for shale gas development in the Karoo. These include independents such as Falcon Oil & Gas and Bundu Gas and Oil Exploration, supermajors such as Royal Dutch Shell, other national oil companies such as Statoil, and other relatively large and dynamic companies such as Chesapeake Energy and Sasol. Although PetroSA itself has not yet applied for shale gas exploration rights, under current regulation, companies that obtain production permits will have to cede to PetroSA a 10 percent stake in their projects.

Figure 28. Estimated South African Shale Gas Resources, 2011

Basin	Risked Gas In-Place (tcf)	Technically Recoverable Resource (tcf)
Prince Albert	453	91
Whitehill	995	298
Collingham	386	96
Karoo Basin (total)	1,834	485

Source: U.S. EIA, "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside of the United States," April 2011.

The development of the shale gas of the Karoo faces at least some uncertainty. Many of the complicating factors are similar to those threatening the shale gas revolution in other parts of the Atlantic Basin — as in France, where the government has provisionally prohibited the use of fracking methods to extract shale gas, or as in the United States, where resistance from environmental and local groups has placed in doubt the future of even U.S. shale gas (which

²⁰⁷ The three shale formations of the Karoo Basin possess 1,834 trillion cubic feet of risked gas in place, and 485 tcf of technically recoverable resource, compared to estimated global shale reserves of 22,016 tcf (RGIN) and 5,760 tcf (TRR). See U.S. EIA, "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside of the United States," April 2011.

has experienced a revolutionary expansion of production). The primary issue tends to revolve around water — both the increased demand on local water supply and the potential disturbance to (and/or contamination) of the water tables (see the subsection on Shale Gas in the Atlantic Basin in the section on the Upstream).

Access to adequate water supply for fracking purposes will be at least a challenge in the Karoo Basin, as the semi-desert area has limited water resources. Environmental critics have been joined by many local farmers (particularly sheep farmers) but also by wealthy landowners in the Karoo Basin in resisting the attempt to exploit the region's shale gas resources. Enough opposition to shale gas in the Karoo had coalesced by February 2011 to prod the government into placing a temporary moratorium on the processing of all new exploration and production rights in the Karoo (although it has been recently lifted for pilot wells).

But until Shell and Sasol actually engage at least in some initial exploration, both the environmental and the resource questions remain open. The shale formations in South Africa are different from those in North America, where the combination of hydraulic fracking and horizontal drilling have produced a significant expansion of reserves and production. Although most expert opinion would place the odds at being very high that the Karoo holds significant reserves, some remain unconvinced, whereas many others believe that economic and environmental issues — beyond the central issue of water — might serve as sufficient barriers to successful commercial development of the basin's shale gas.

First among these additional barriers is the potentially significant issue of fugitive emissions of methane during the fracking process. One of the great advantages of gas with respect to oil or coal is supposed to be its significantly lower level of CO₂ emissions — two-thirds those of oil and about half those of coal. However, a number of studies have concluded that if secondary releases of methane cannot be contained, shale gas production (measured on a life-cycle basis) is likely to emit more greenhouse gases than either coal or oil.

Another barrier is the fact that the Karoo is far removed from any serious economic activity. Yet this structural feature of the basin is not necessarily a bad thing. Often huge tracts of land need to be cordoned off to be able to efficiently and safely control the fracking

process and to deal with heavy machinery. Sparsely populated areas might be more convenient, in the end, if appropriately inclusive deals are struck with local and environmental groups that might otherwise be inclined to try to block shale gas development in the Karoo.²⁰⁸

In addition, there is an infrastructure constraint. Currently, most industry cannot take on gas, either as a feedstock for production or as an energy input, without a significant retooling, given that the large bulk of South African industry is powered by electricity. Nevertheless, gas is currently needed for the Mossel Bay GTL plant, and it could be used to fire much of Eskom's electricity capacity "build plan" (see the subsection on Eskom below).

South Africa actually already has some experience using hydraulic fracturing. The technology used to exploit coal-bed methane at its giant Waterberg coal mine is very similar to that used in the horizontal boreholes of shale basins in the United States. According to South Africans intimate with the Waterberg mine, fracking has been used without damaging the water tables or provoking fugitive emissions, indicating that South African companies might have an edge on international firms in exploiting the shale gas of the Karoo. Still, the coal-bed methane fracking technique in Waterberg is employed to depths of around 400 meters; the shale gas of the Karoo is estimated to lie 5,000 meters below the surface.

The most recent policy goals of the South African government, revealed in the current version of the Integrated Resources Plan (IRP) 2010, call for the expansion of nuclear power from its current 1.8GW of capacity and 5 percent of the electricity mix to 11.4GW of capacity and 20 percent of the generation mix. The goals for renewables are even more ambitious if South Africa is going hit its targeted emissions path (see the subsection on the IRP 2010 below). However, if nuclear power drops out of South Africa's energy future (as a result of a policy change in the wake of the recent Japanese experience), then even committed environmentalists concede that shale gas will become that much more important for South Africa in the future. The alternative is to stick with cheap, dirty domestic coal for most energy needs in South Africa.

²⁰⁸ Here, lessons might be learned from across the southern Atlantic. See Patricia Vazquez, "Energy and Local Conflicts in Latin America," Inter-American Dialogue Energy Group, Washington, DC, 2010.

In the end, however, if large reserves in the Karoo Basin can be confirmed, and if mounting local resistance in the Karoo to shale gas development can be overcome, then the rapid emergence of unconventional gas — particularly shale gas production in the United States — will have created a potential opportunity for South Africa to become a significant gas producer. Major domestic gas production would provide the country with the capacity to slowly displace coal from its central position in the electricity mix, but it could also quickly begin to replace petroleum as the principal feedstock for transportation fuels.

3.2.7 Obstacles to South African Energy Transformation

South Africa has the potential to dramatically reshape its energy map and emissions profile. Still, it faces a number of legacies from the apartheid era that would slow the progress of any energy transformation. First, the country is characterized by lingering, widespread poverty. Although the economy has grown rapidly since the apartheid era ended in 1994 (particularly in the 2000–2008 period), and is now one of the most developed economies in sub-Saharan Africa (South Africa was recently invited to join the BRICS grouping of major emerging markets as the “S”), about one-third of the population still lives on less than \$2 per day and one-quarter still lacks access to electricity and other modern energy services.²⁰⁹ Furthermore, racial tensions persist in South Africa. Although economic development does proceed apace, it is not necessarily occurring fast enough to keep up with a revolution of rising expectations among the poorer black African masses. This divide, while not insuperable, also tends to spill over into the debate over energy policy and climate strategy.

South Africa’s nationwide electrification rate is 75 percent, the highest in sub-Saharan Africa. Nevertheless, the energy poverty rate (the percentage of the population without access to modern household energy) is still high. Only 55 percent of the rural population enjoys access to electricity, compared with 88 percent in the country’s urban areas. In addition, approximately 12 million

²⁰⁹ From 1995 to 2000, average family income declined. In addition, South Africa ranks among the ten countries of the world with the most unequal income distribution, as measured by the Gini coefficient. Nevertheless, during the strong growth spurt from 2000 to 2008 (8 percent GDP on average annually), both of these tendencies were moderated to some degree.

people had no access to electricity as of 2008 and relied heavily on wood fuel to meet their heating and cooking needs.²¹⁰

The government's Integrated National Electrification Programme (INEP) is attempting to achieve universal access to electricity by 2012. The former Department of Minerals and Energy (which has since been split into two departments) began promoting the use of liquefied petroleum gas (LPG) in rural areas a few years ago to meet the basic needs and mitigate the health and environmental impacts associated with burning wood fuels and coal. But electricity capacity constraints in the wake of a significant power crisis in 2008, along with a shortage of the natural gas need to support a relatively expensive LPG program, could foil South Africa's energy poverty goals, or at least delay their realization beyond the related target date (2015) of the Millennium Development Goals. On the other hand, eliminating energy poverty would be facilitated greatly by the discovery and successful exploitation of the large estimated shale gas reserves of the Karoo Basin.

The post-apartheid government has had mixed success trying to bridge the economic and racial divides. Through its Black Economic Empowerment (BEE) program, it has committed itself to ensuring that black-owned companies have access to the existing economy. The BEE program for the energy sector set a target of 25 percent black ownership of energy companies by 2014. Although the BEE criteria have been loosened and broadened on a number of occasions over the last several years, the predominantly white-owned energy corporations have been hiring and selling assets to Black South Africans in order to achieve this objective.

Unresolved poverty, uneven development, and lingering racism in South Africa will certainly make the country's energy and climate challenges more difficult to resolve. The traditional dominance of monopolies (state and private) in the country's strategic sectors, another legacy of the apartheid era, also provides for a difficult policy environment. Under the apartheid regime, the de facto energy strategy was control by the major South African parastatal companies (such as Sasol), and the same was true for the country's economic development strategy. The same companies today, whether now in public or private hands, still tend to dominate

²¹⁰ EIA, Country Analysis Briefs: South Africa, March 2010.

the energy policy arena, but they tend to resist, formally and informally, most of the more ambitious policy thrusts of the post-apartheid government.

Chief among related obstacles is the legacy of very low and controlled energy prices, an issue that has complicated energy balances and energy policy in many developing countries around the world. With large reserves of cheap coal, on one hand, and very low electricity prices — controlled by the state and, on average, among the lowest in the world (although they have recently begun to rise noticeably), on the other, South Africa faces the tricky task of both reducing its consumption of coal (or at least reducing the greenhouse gas emissions released by its burning) *and* increasing the domestic price of energy, bringing it more in line with its underlying economic cost (including at least some of the externality represented by greenhouse gas emissions). Furthermore, South Africa must achieve such a dual change without provoking debilitating political backlashes from either the “minerals-energy complex” — a traditional network of power still dominated by wealthier white South Africans — or the masses, dominated by poorer black South Africans long accustomed to very low energy prices underpinning their historically meager — if now slowly rising — purchasing power.

During the last decade, the restriction of greenhouse gas emissions has emerged as one of the central long-term energy challenges facing South Africa, and the world. In the short run, however, given the current structure and dynamics of the country’s electricity sector, along with the existing regulatory framework, the country’s most significant energy risk is that South Africa’s electricity generating capacity will prove insufficient to fully cover demand over the next few years without experiencing continuing shortages and rolling brownouts (“load shedding”), particularly during the winter months.²¹¹ It would be a challenge for South Africa to meet future electricity demand through a capacity buildup based entirely on coal; the goal of expanding output while reducing coal’s relative share of the energy mix will be even more difficult to achieve.

²¹¹ In this sense — although for different reasons — South Africa resembles Argentina.

For better or for worse, the country's energy economy is dominated by what some South Africans call the "minerals-energy complex."²¹² This interlocking web of mineral, energy, chemical, and other heavy industrial companies — such as Sasol and Eskom — is essentially based upon the mining, burning, and transformation of coal, the country's most bountiful and cheapest fossil fuel. Coal's dominant position in the electricity matrix feeds the traditional large-scale, energy-intensive mining sector in South Africa and, by extension, the entire South African economy, dominated as it is by activity from the minerals-energy complex.

Electricity is at the nexus of the minerals-energy complex — 70 percent of electricity generated goes to industry and mining. In the South African electricity realm, the legacies of apartheid and its state-dominated economy, together with the overwhelming centrality of fossil fuels, are all found bound together in the current situation of Eskom, the formerly white-dominated, but still state-owned, electricity monopoly. Among other recent changes and challenges, Eskom is now adjusting to the imperatives of the BEE program, partial liberalization of the electricity generation sector (to allow for private competition in generation), increasingly tight constraints posed by carbon dioxide emissions, and, most immediately, the pressing need to finance significant generation capacity expansion to ensure that South Africa's burgeoning electricity demand will be covered without resorting to load shedding. Let there be no mistake: Eskom is even more key than is Sasol for South African energy transformation.

A long cycle, punctuated by a number of external and internal shocks (including international sanctions and the end of apartheid), has played itself out in the South African electricity sector since the 1970s. In contrast to most other countries, particularly in the developing world, the oil crisis of 1973–1974 and subsequent global recession did not notably dent South African energy demand, which continued to grow at around 12 percent each year throughout the decade. This was partly because of continued strong growth in the South African minerals sector, and partly due to South Africa's relative isolation from the world economy at the time.

²¹² See Ben Fine and Z. Rustomjee, *The Political Economy of South Africa. From Minerals-Energy Complex to Industrialisation*, London, Hurst, 1996.

In response to this rapidly growing energy demand, a large buildup in electricity generation capacity was rolled out in South Africa over the course of the 1970s and 1980s.²¹³ Facilitating this infrastructural rollout was government policy allowing state-owned Eskom's end-tariffs to be high enough to guarantee sufficient return on the company's capital investment — the well-known cost-plus tariff formula. Nevertheless, South African end-tariffs, in absolute and relative terms, remained among the lowest in the world over this long period, primarily as a result of the extremely cheap nature of South African coal and the state subsidies applied to keep end-tariffs for certain key groups even lower. This excessively low price for electricity has served as one of the fundamental barriers to generation capacity expansion in South Africa. It has also hidden from public view the true economic cost of energy, embedded in “market externality” represented by South Africa's excessive CO₂ emissions.

But the global recession of the early 1980s, in part provoked by the second oil-price shock of 1979–1980, did affect the South African economy negatively. This was, in part, because the global recession was longer and more severe in 1980–1982 (when the rand was falling against the dollar) than in 1974–1975 (when the weak dollar improved the international terms of trade of South Africa's commodities-based economy). Furthermore, the second oil shock and subsequent recession also coincided with a period of increased international pressure to tighten trade sanctions against apartheid South Africa. This time around, therefore, energy demand fell in line with the global trend and the national electricity growth rate dropped dramatically, leaving South Africa with as much as 40 percent overcapacity in electricity generation well into the 1990s.

With the dissolution of the apartheid regime in the 1990s came the democratic transition, the beginnings of economic reform, and, by the turn of the century and in the wake of the Kyoto Protocol, a new imperative to reduce carbon emissions. In the energy sector,

²¹³ Such rapidly growing energy demand, even in the face of sharp global recession, was itself an expression of the relative success of the South African industrialization process, which, had it not been for widespread black African poverty under apartheid, might have merited South Africa's classification as a newly industrializing country (or NIC) during the 1970s. It would clearly take the end of the apartheid regime and nearly two decades of “triple transition” (political, economic, and low-carbon) for South Africa to qualify for the BRICS, the grouping of large and influential “emerging market” economies (the others are Brazil, Russia, India, and China).

the political transition made itself felt most notably through the BEE program, which has, for better or for worse, produced certain dislocating effects for the coal-mining sector and for Eskom power generation (as analyzed in the above section on coal). Among other factors that feed into the supply-demand balance, the adjustments required by the BEE program have hampered the sector's ability to successfully keep up with rising demand at all times while avoiding load shedding or brownouts.

On the other hand, economic reform has also continued, only not as quickly — and not in such a linear fashion — as in some other developing countries. In the energy sector, for example, a plan to privatize Eskom in the 1990s was abandoned in favor of a “strategic stakeholder relationship” between the state and the company in which the government would evaluate the company on a performance basis along the lines of a commercial model. Nevertheless, this model would remain subject to modification so as to accommodate a number of social and economic objectives of the government (such as BEE and affirmative job creation). Given the strong privatization winds blowing through transition countries during the 1990s, it seems prescient that the government in the end decided not to withdraw from such a strategic sector so quickly, particularly in light of the global repoliticization of energy and energy policy — among both net energy importers and net energy exporters — over the course of the first decade of this century.

Furthermore, a partial liberalization of the electricity market over the last decade has tried to encourage the entry of independent power producers (IPPs) into the power generation sector. As the past decade has progressed, the South African government has increasingly given priority to renewable energy IPPs within its long-term plans to both: 1) double generation capacity over the next 20 years and 2) decarbonize as much of this massive required new build program as possible. In order to encourage IPPs and renewables to take up as much of the projected new generation capacity as possible, for years the government refrained from allowing Eskom to proceed with a vigorous capacity expansion program. Given the enormous cost advantage that cheap coal represents for Eskom, however, the financial terms of government support — mainly feed-in tariffs (FIT) for IPPs and certain renewables (REFIT), such as wind and solar power

— have not been sufficient to lure new entrants into the power market supplying to the grid. Presently, not a single renewables IPP is generating power for the grid, and only a very few other conventional IPPs contribute an additional 2,000MW of capacity to Eskom’s 41,000MW.

Changes to South Africa’s electricity support schemes also have not always helped to facilitate the rollout of new IPP generation capacity, particularly in renewable energies. Although the REFIT levels that renewable power producers might enjoy have been adjusted *downward* in recent years, feed-in tariffs are not automatically available to all potential producers. Rather, the government has maintained a stringent vetting policy that, in the end, has slowed the early phases of liberalization and decarbonization of the electricity market in South Africa more than might have been necessary (see also the subsection on South Africa in section 2.5.5, Renewable Energy in the Atlantic Basin).

The end result of the government’s earlier restraint upon Eskom capacity expansion (which was eventually acknowledged), together with its failure to stimulate significant investment from IPPs, has been to make the electricity supply-demand balance even more difficult to maintain, even in the short run. Together with some more technical factors, this failure was at the root of the South African power crisis of 2008, which threatened to re-emerge during the World Cup celebrations in the summer of 2010. Given the imperative to eliminate energy poverty (affecting 25 percent of the population) as rapidly as possible, the question of expanded capacity, all along the electricity supply chain, has become paramount — just as it has in a number of other key emerging national players within the Atlantic Basin (including Morocco, Brazil, and Argentina). A shortage of power in South Africa, however (whether anticipated through load shedding or not), would complicate and delay any progress against energy poverty, just as it would undermine the government’s job creation and climate goals, given that the economy’s central engine, the energy-minerals complex, depends highly on massive inputs of cheap electricity.

3.2.8 South African Strengths and Tailwinds

Considering the obvious challenges facing South Africa on its current path toward what would be a remarkable “triple transition” — from the poverty of undemocratic apartheid, with its state-dominated economy and extreme fossil fuel dependence to a prosperous democratic state with a market-based, low-carbon economy — some political and economic instability is foreseeable in the short- to midterm future. Any such instability, however, should prove manageable, given South Africa’s special strengths and the tailwinds at its back.

After all, South Africa is the dominant economy in Africa and the continent’s leading industrial power. Diplomatically, the country is increasingly central among the world’s most successful emerging markets. South Africa’s political and economic influence on the continent is unrivaled by any other single African country, and the foreign investment of its companies makes the country among the global leaders in foreign direct investment on the continent. Should the currently unfolding political and economic transition continue to successfully evolve, South Africa’s influence over the continent will only increase.

In terms of global geopolitics, the country occupies a strategic position on the world’s sea lanes, at the meeting point of the Atlantic and Indian oceans, lending it both opportunities and influence over the increasingly sea-bound international energy trade in oil, liquefied natural gas, and coal. The Cape of Good Hope is a significant point for oil tanker transit around the continent, making South Africa an important energy transit state. Approximately 1.25mbd of oil from West Africa traveled east around the Cape toward Asian markets in 2009, while at the same time, 2.25mbd originating in the Middle East went west around the Cape into the Atlantic Basin.²¹⁴

Given renewed instability in Egypt (the Suez Canal) and Somalia (at the entrance to the Red Sea), the Cape passage is becoming even more strategic. As a result, the Cape Town container terminal now plans to double its capacity. Although the long-term strategy of balancing oil import supplies from the Middle East with imports from oil-rich “Atlantic Africa” could be called South Africa’s

²¹⁴ According to Lloyd’s Analysis of Petroleum Exports (APEX) database.

“Atlantic hedge,” it also serves to help solidify the country’s relations with fellow African countries, bolstering South Africa’s diplomatic weight on the continent.²¹⁵

South Africa is also an enthusiastic supporter of the UN-sponsored global climate negotiations and was the host of the Conference of the Parties (COP17) at the Durban Climate Summit in 2011. At the Climate Change Summit in Johannesburg during 2009, the Department of Environment Affairs had announced South Africa’s aspiration for its CO₂ emissions to increase only until 2020–2025, then plateau for a decade, and finally decrease in real terms after 2030–2035. Then, during the Copenhagen Summit at the end of that year, South Africa announced that it could decrease its greenhouse gas emissions significantly (more than a third) below the business-as-usual trajectory, provided that sufficient international financial support was forthcoming to successfully implement such a mitigation strategy and that a legally binding international agreement finally be achieved..

3.2.9 Conclusion

Although legacies from the past and myriad obstacles on the ground will no doubt make for a bumpy political ride, South Africa has a constitution and a set of environmental laws already on the books that at least provide for a pathway into the future for progressive energy and environmental policy. For better or for worse, however, South Africa’s success in achieving the third aspect (the transformation of the coal-dominated energy sector into a low-carbon economy) of the triple transition will depend heavily on the resolution of continuing obstacles to the economic and political aspects of this transformation.

²¹⁵ South Africa’s Atlantic African energy hedge has been a key element over the years in the country’s geopolitical strategy. On the other hand, the marginal advantage of supply from Angola and Nigeria — versus that from the traditionally volatile and OPEC-dominated Persian Gulf — has been eroded over the years by the significant run-up in oil prices (reducing the relative weight of crude transport costs in the final price of oil), by the entrance of Angola into OPEC, and by the increasing potential for instability in the Gulf of Guinea).

4. The Future of an Atlantic Basin Energy System: Conclusions and Policy Implications

The Atlantic Basin and Energy

1. In recent years, the political cohesiveness of the Cold War “transatlantic community” has weakened considerably. The globalizing shocks of the post–Cold War era have catalyzed a number of international shifts in relative power, issuing the first signs of a potential “crisis of the West.” At the same time, the West’s center of gravity (and dynamic internal composition) has begun to shift once again — this time from north to south. The countries of the southern Atlantic are becoming increasingly relevant, if not central protagonists, in the structure and dynamics of geopolitics within the Atlantic space.
2. Today, the Atlantic Basin takes on new meaning as an analytical lens and strategic framework that emerging market countries in the southern Atlantic might leverage to improve their geopolitical flexibility and economic prospects. The concept of the Atlantic Basin might even serve as an inspiration for a revived and transformed West, or for at least a reconfigured Atlantic space.
3. Energy and climate issues, in particular, have become key Atlantic vectors, as the Atlantic Basin re-emerges as an important subsystem within the global political and energy economy alongside the Pacific and Indian Ocean basin-systems. An incipient Atlantic Basin energy system may also hold at least one of the keys to any such revival, or reconfiguration, of the Atlantic world.
4. If the United States remains the fossil fuel center of the Atlantic Basin, Europe is the basin’s leader in nuclear power and modern renewables. Latin America leads in hydropower and biofuels, while Africa still looks to eliminate its energy poverty even as it aspires to reducing its carbon intensities. South Africa (a leader

in synthetic transportation fuels) and Morocco (a pioneer among developing countries in modern renewable energies) are strategically well positioned to lead the way among the Atlantic countries of Africa.

The Center of Gravity Shifting South

1. The shifting energy landscape of the Atlantic Basin also reveals a relative movement in the center of gravity for both energy demand and supply from economies in the north, in general, down to economies farther south. The Southern Cone and Southern Africa have recently emerged as new centers of gravity within the energy landscape of the Atlantic Basin. It is in the southern Atlantic where most of the new energy trends are now emerging with the most force and the greatest potential for transformation.
2. Brazil, Morocco, and South Africa — and, to a lesser extent, Angola and Argentina — are now essential actors within the Atlantic energy space. Each of these countries has unique strengths and potential value added to contribute to the strategic rethinking of the potential for the Atlantic Basin concept as a geopolitical and economic frame of reference. More than any other countries of the developing South, these three have the unique opportunity to act as pioneers in any effort to conceive of and foster Atlantic Basin systems and, in the future, any potential Atlantic Basin communities.

An Incipient Atlantic Basin Energy System

1. An Atlantic Basin energy system does not exist, per se. At present, it can only be abstracted from one of many overlapping subsets of the global energy system. There is not yet an Atlantic Basin consciousness, and only a few policy thinkers have begun to pioneer the concept.
2. Nevertheless, certain prototype Atlantic subsystems already do exist to a large degree in the form of the regional Atlantic Basin markets for crude oil, liquefied natural gas (LNG), coal, petroleum-derivative products (gasoline, diesel, etc.), and hydrocarbons equipment and services, even against a backdrop of increasingly globalized energy markets.

3. A number of the necessary basic prerequisites are already in place that could allow for continued development of other Atlantic Basin energy subsystems in the crude oil and natural gas realms, but particularly in the shale gas sector and in the refined transportation fuels market, notably through the expanded use of synthetic fuels and gas-to-liquids (GTL) technology.
4. Surging energy consumption, particularly in the southern Atlantic, is developing the system on the demand side. The southern Atlantic alone could account for as much as 20 percent of global energy demand by 2035, with the entire Atlantic Basin contributing nearly 40 percent. The expected boom in southern Atlantic energy demand lends the Atlantic Basin energy space more vital critical mass within the global energy system.
5. The ongoing hydrocarbons and renewables boom in the Atlantic is driving the development of this system from the supply side. The discovery and development of new oil and gas reserves up and down the Atlantic — along with the progressive transfer of new low-carbon technologies and large-scale development and rollout of renewable energy resources — could significantly deepen and broaden the interactions underpinning the Atlantic energy markets. Already, the Brazilian pre-salt exploration has kicked off a deep offshore boom in the southern Atlantic — which has caught on in Angola and Ghana, and could also explode all along the West African Transform Margin — that could potentially coalesce into a southern Atlantic oil ring. This, in turn, could reduce the dependence of many Atlantic Basin countries on Eurasian energy sources, taking pressure off their intensifying competition with China and India over energy from the world's most unstable regions in the Middle East and Central Asia.
6. Intra-Atlantic Basin trade and investment, across the energy spectrum, is on the rise, in absolute terms and relative to the other basins and the global system, and now accounts for as much as 40 percent of the world's energy economy. Given its heavy weight in global energy markets, and considering the depth and coherence of the basin markets themselves, the

Atlantic Basin now wields substantial critical mass in terms of global market and political influence in the realm of energy. Indeed, as energy and climate change continue to displace regional integration and free trade agreements on the global policy agenda (although recently this tendency has reverted, at least temporarily), there could well be a resurgence of the geopolitical weight of the Atlantic Basin, based precisely on the size, depth, and dynamism of its internal energy markets. In any event, combined with the boom in Atlantic energy supply, the growing density of the intra-Atlantic energy trade suggests that an Atlantic Basin energy system might now exist at an incipient stage.

7. Meanwhile, the Atlantic Basin is increasingly self-sufficient at the basin level, augmenting its relative independence and autonomy with respect to the rest of the global system. Finally, there are a number of identifiable mutually complementary opportunities to develop potential investment and trade links across the Atlantic (and particularly in the southern Atlantic) in the area of new energy developments (sugarcane-based biofuels, shale gas, and gas-to-liquids, along with hydropower and modern renewables) that are relatively low in the emission of carbon dioxide (CO₂) and could actually tip the balance of energy geopolitics in the direction of the Atlantic Basin.
8. Complementary investment and trade opportunities exist in the downstream — particularly in the biofuels sector between Brazil and the Atlantic countries of West and Southern Africa. Furthermore, some opportunities in the upstream (such as Argentine shale gas) are also complementary with certain developments and potentials in the downstream (South Africa's gas-to-liquids technology). Potential complementarity also exists for profitable and productive intra-Atlantic Basin investment in the realm of electricity generation, transmission and distribution infrastructure, international interconnections, and regional electricity market development (e.g. DESERTEC, the Southern African Power Pool, SIEPAC, etc.).
9. The development of some of these subregional complementarities would serve as a powerful catalyst for the development of an Atlantic Basin energy system. A surge in

transnational energy-related investment within the Atlantic world (led by an expansion and deepening of intrabasin energy trade) has the potential to tip the balance of energy geopolitics back in favor of the Atlantic world, while at the same time significantly reducing the basin's carbon footprint.

10. Such possibilities offer southern Atlantic countries the chance to wean themselves off the lower-value-added portion of the energy supply chain (crude oil and ethanol feedstock, for example) and even to export, potentially, a whole range of petroleum, bioenergy, and synthetic fuel products, particularly in the light- and middle-distillate realms.
11. The majority of the most significant trends in global economy, energy, and geopolitics point in the direction of increasing weight, dynamism, autonomy, and global influence for the Atlantic Basin energy system. The revolutions in deep offshore oil and shale gas will add to the Atlantic Basin energy supply and reduce energy dependence on extra-Atlantic sources, moderating geopolitical friction with both extra-Atlantic suppliers such as Russia, and extra-Atlantic consumers such as China, as both respond to the increasingly buyers' market in ways that ease potential conflict with the countries of the Atlantic Basin (particularly with the EU and the United States). Given a higher potential participation in these two revolutions, the Atlantic Basin is poised to develop the cutting edge of the shale gas, deep offshore oil, and low carbon industries to become the global reference in technology and best-practices.

The Gas Revolution and the Atlantic Basin Energy System

1. Although the Atlantic Basin has not traditionally been known as a gas power — when compared with the Middle East or Eurasia, at least (and with the sole exception of the United States) — a successful shale gas revolution would provide a significant stimulus for the development of an Atlantic Basin energy system and an Atlantic Basin consciousness. Therefore, the debate over shale gas now under way should be dealt with scrupulously, taking into account the positions of various stakeholders and assessing widely ranging environmental,

technical, and cost profiles and potentials of international shale basins.

2. The countries of the Atlantic Basin should pursue both a “gas bridge” to a low-carbon future, and vigorous renewable energy rollout. National players in the southern Atlantic should seek financial partnerships within the Atlantic Basin to support the wide-scale deployment of renewable energy.
3. The economic incentives of geography will eventually impose themselves, generating more intra-Atlantic Basin energy investment and trade, in both fossil fuels and alternatives, all along the energy chain. The political incentives of geography (reduced import dependence on the volatile “Great Crescent” of the Middle East and Eurasia, and less direct geopolitical competition with the consumers of South and East Asia) will then dovetail with the economic incentives.
4. The shale gas revolution has the potential to roll out a “gas bridge” to a low-carbon future dominated by current and future generations of modern renewables. Large quantities of cheap gas would compete with coal and oil, and eventually significantly displace them within the energy mix of the Atlantic Basin, both in generation (through substitution) and in transportation (through potential application of GTL technology).
5. Wider use of gas could potentially reduce carbon emissions significantly over the middle run, buying crucial time in the struggle to cap CO₂ concentrations, until renewables are capable of finally achieving mass scales some 20 to 30 years into the future. Furthermore, a higher share of gas within the electricity mixes of the Atlantic Basin might also enhance the capacity of national electricity systems to absorb ever-higher shares of intermittent modern renewables.
6. However, a risk exists that a successful shale gas revolution will instead compete with the current renewables rollout effort, as gas prices become permanently delinked from those of oil, increasing further the current cost differentials associated with renewable energies. An increasing number of voices in both the conventional and unconventional gas worlds now argue

that the shale revolution should be harnessed to reduce carbon emissions more quickly and cheaply in the short run than can be achieved with the current rollout pace of present-day generations of renewables.

7. Rather than committing substantial state support in continuing to roll out the current generation of renewables, this school of thought would claim that cheaper gas should be used to substitute first for coal and then for oil, but with the cost savings invested, not in state support for current renewables rollout, but rather in R+D in future renewable energy technologies. Such voices argue that this “pure gas bridge” strategy, by redistributing investment from current rollout to future research breakthroughs, will allow for innovation to drive down the cost of renewable energy more efficiently and rapidly over the long run.
8. However, the countries of the Atlantic Basin, particularly those of the southern Atlantic, should exercise critical skepticism with respect to the “pure gas bridge” option. It would be foolhardy for any country in the Atlantic Basin — but particularly for the emerging economies of the southern Atlantic — to forgo the burgeoning opportunities that abound today to develop low carbon energy sectors (including, in many cases, the associated manufacturing and service sectors). Even if such a “pure gas bridge” strategy proved successful on a wide scale, many countries would in the meantime potentially lose out on the opportunity to improve the competitiveness of their economies within the budding global low-carbon economy.
9. Finally, prudence argues for pursuing an “integrated gas bridge.” It is far from clear that shale gas will overcome the various potential environmental risks that have been identified. Even should the “fracking” controversy be resolved positively for the shale community, there remains the risk that shale gas — through fugitive emissions of methane — will end up with an even more significant carbon footprint than that of oil or coal. *Under current global geopolitical, economic, and energy circumstances, shale gas should be given, at least for now, the benefit of the doubt. Under no circumstance should shale be allowed to constrain the growth of renewable energies.*

Renewable Energy in the Atlantic Basin

1. Currently the Atlantic Basin dominates the global renewable energy scene. Of the nearly 200GW of installed wind capacity in the world, 64 percent is located within the Atlantic Basin. Furthermore, more than 80 percent of the world's current installed capacity in solar power is located within the basin, although admittedly most is still in the northern Atlantic. On the other hand, four-fifths of global activity in biofuels takes place within the Atlantic, and at least much of it is connected to the south. Furthermore, conditions now look more favorable for rapid growth in the southern Atlantic.
2. Global investment in renewable energy has continued to grow (to \$211 billion in 2010). However, as the crisis hit growth and investment in the North, and as political pressures blocked further “green stimulus,” pared back other state-support schemes, and blocked legislation that would facilitate the global pricing of carbon emissions, global renewables investment shifted to the developing world. Much of this has recently been further committed to pushing renewables, even if still insufficiently, despite the intense budget difficulties that many national governments face in the developing world.
3. As political barriers to renewable energy and insufficiently rigorous carbon restrictions continue to cloud the near-term future of renewable energies in the northern Atlantic, a number of southern Atlantic countries — Brazil, Mexico, Argentina, Morocco, and South Africa (in addition to China and India in the extra-Atlantic) — are poised to become world leaders in renewable energies. They are also expected to receive an increasing share of global FDI (much of which will come from China and India), helping to underpin their renewables boom. In 2010 alone, Brazil registered more than \$6 billion in renewable energy investment.
4. The countries of the southern Atlantic are gaining some initial relative advantage in different segments of the alternative energy markets (wind and biomass in Brazil, wind and solar in Morocco, solar water heating and GTL in South Africa). Such countries are likely to benefit in relative terms from their early positioning in the market for alternatives to the currently

configured fossil fuel dominance as such markets expand globally in the future.

5. This rising influence of the developing world — and of the southern Atlantic — within global renewable energy markets has been both cause (providing for larger scales) and partial effect (benefiting from innovation in the advanced economies) of the downward evolution of renewable energy costs experienced in recent years. The cost of solar power has fallen by 60 percent since the summer of 2008 and is now competitive for the first time with the peak-time retail price of electricity in a number of sunny economies, even with few or no subsidies. In many developing countries, distributed use of solar power is already competitive with diesel fuel (used in small-scale distributed generators), its main “off-grid” competitor. Wind turbine prices have also fallen significantly (18 percent per megawatt over the last two years), reflecting the same vibrant competition found all along the solar power supply chain.
6. The price of solar power must still fall significantly, however, before it can compete effectively on a global scale with fossil fuels in electricity generation — even if governments increase fossil fuel prices to reflect more fully the cost of carbon emissions. The cheapest solar power now costs \$120-\$140/MW; onshore wind power in the United States costs \$70/MW and gas-fired power some \$70-\$90/MW; meanwhile, coal-fired electricity is even cheaper than gas and wind.
7. Given the length of the economic crisis and the relatively hostile political atmosphere surrounding the pricing of carbon emissions and state support for renewable energies in the northern Atlantic, growth in renewable energies may moderate for some time in the United States and the EU.
8. In the southern Atlantic, the story could be very different, however, as the center of gravity in the renewable energy industries shifts to the developing world (where China dominates on the global scale), and from the northern to the southern Atlantic.
9. A number of obstacles still complicate the way forward for renewable energies, even in the southern Atlantic. Foremost

among them will be the fallout from the renewables bubbles in the Atlantic Basin, particularly in the solar markets, as the overhang in excess capacity is absorbed and eliminated from the supply chain. Furthermore, the recent pullback in state support, particularly in the northern Atlantic, along with the tightening of global credit (especially for smaller players) is bound to reduce renewable energy growth rates in the EU and even the United States. The end of stimulus spending in the northern Atlantic will only reinforce this tendency.

10. The lack of recent progress at the global climate negotiations has also precluded the formation of a sufficiently high global price for carbon emissions. The way ahead is further clouded by a broad global patchwork of subsidized electricity and fuel end-use prices, along with additional subsidies for fossil fuel production.
11. Despite some rapid renewable energy growth rates, very few countries in the developing world have proved capable of creating clear and attractive incentive schemes. Brazil has been a major exception, but it is now phasing out its feed-in tariffs, and others — such as Morocco and Mexico — have decided against such direct support schemes, at least for now. Brazil, in the end, may be proved right in shifting now to a more competitive model, but to a large degree, its future success will have been built upon the early years of government support through the PROINFA renewables feed-in tariff scheme — suggesting to Morocco and Mexico, perhaps, that more strictly competitive market models, at least for renewables, might still be somewhat premature.
12. Subsidies to fossil fuels should be phased out, efforts should be made to effectively price emissions, and more state support given to renewables rollout. *Such measures are particularly important given the potential for gas to crowd out future renewables growth should the shale gas revolution prove as successful as its many proponents believe.*
13. The issue of financing will remain critical. Actors within the Atlantic Basin should explore the potential financing opportunities to be leveraged from new international financing mechanisms, such as Norway's recently announced Energy+

financing platform, the UN's global REDD+ platform, the Global Environmental Facility (GEF), the Climate Investment Funds (CIF), the Green Climate Fund, the Inter-American Development Bank, and the Africa Development Bank, among others.

Price Environments

1. The quadrupling of the world oil price over the last decade has led to an incipient hydrocarbons boom in the Atlantic Basin, while at the same time contributing significantly to the first true global blossoming of renewable energies. The unfolding global renewables rollout (with its step-jump in scale) has itself contributed significantly to falling break-even prices for most forms of renewable energy. Nevertheless, this decline in production costs has not yet been steep enough to close the cost differential with fossil fuel competitors. Although the ETS carbon price -- for the moment, the most significant international reference -- has generally been weak (\$10 to \$20 per ton, although recently as low as \$2-\$3), it is expected to be \$20 to \$30 per ton over the coming years, with little but upside potential feasible in the future.
2. Prices will need to be high and stable enough to stimulate: 1) sufficient investment (\$800 billion annually, according to the IEA) for supply to continue to meet growth-driven increases in energy demand; but also 2) the additional investment needed (\$90 billion annually) to check developing world carbon emissions sufficiently to avoid breaching the 2 degree Celsius temperature increase limit posited by the UNFCCC.
3. The long-term price trend is clearly upward. With global oil prices hovering around \$100/bbl today, the IEA now projects that prices will average \$103/bbl through the midterm to 2015, rising to \$133/bbl by 2035. In recent years, coal prices have risen just as dramatically as have those of oil, and along a similarly volatile pattern. Given coal's continuing large contribution to the global energy mix — but particularly to the Asian economies, where energy demand is growing the fastest — coal prices in all probability will remain strong. Gas prices have moderated considerably, particularly in the Atlantic Basin,

but only as a result of the shale gas revolution in the United States — stimulated, in part, by historically high gas prices — and this situation has significantly eroded the once-tight link between oil and gas prices.

4. *Strong and rising energy prices will continue to serve as a partial but limited driver of expanded and lower-carbon energy supply in the Atlantic Basin.* However, the supply and quality response — a key precondition for the emergence of an Atlantic Basin energy system — would be strengthened considerably by the progressive elimination of state-induced distortions to the price of energy and carbon.

Energy Policy, Regulation, and Governance

1. High international oil prices, more than any other factors, reinforce the current dominance of energy nationalism over any policy posture that embraces open and inclusive transnational collaboration. Furthermore, competing loyalties to other political, economic, and diplomatic groupings (such as OPEC, the global South, the BRICS, the IBSA trilateral relationship, the BASIC group, and others — even the North’s formal transatlantic relationship) will tend to undermine movement toward energy policy reform and regulatory convergence, to say nothing of the development of an Atlantic Basin consciousness.
2. An Atlantic Basin energy system will have a difficult time taking shape if nationalist energy policies, and internationally competing and internally inconsistent regulatory regimes, continue to weaken potential energy supply, distort the functioning of the Atlantic Basin regional energy markets, and block the rollout of renewables.
3. Energy policy, regulatory regimes, pricing structures, and incentive schemes should be rationalized. Best-practices in policy, regulation, environmental safety, and physical security (particularly for offshore oil and shale gas) should be shared around the Atlantic Basin, and *robust macroeconomic and oil revenue management policies should be fostered in order to avoid “Dutch Disease” or other forms of the oil curse, particularly in the developing countries of the southern Atlantic.*

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4. Another potential barrier to the emergence of an Atlantic energy system is the absence of a diplomatic or governance framework of international relations within the Atlantic Basin resilient enough to sustain the shift of relative power from North to South currently under way, while still developing and deepening the Atlantic system. Today's politically dominant Atlantic frameworks are currently stalled or in a chronic state of malaise. Further development of an Atlantic Basin energy system would probably also require the articulation of at least a proto-Atlantic Basin consciousness, particularly within the southern Atlantic.

Atlantic Basin Consciousness and Geopolitics

1. Nothing even close to an Atlantic Basin consciousness yet exists. Global South identities and loyalties may even generate some initial resistance to the Atlantic Basin concept. However, it is also just as likely that the key emerging countries of the southern Atlantic will identify the Atlantic Basin as a useful strategic hedging device for modifying current geopolitical identities or for moderating more traditional geopolitical dependencies and vulnerabilities.
2. A pragmatic geopolitical use of the Atlantic Basin — demonstrating clear marginal geopolitical value-added — could go far in underpinning a nascent Atlantic Basin consciousness. The development of substantial new energy resources in the Atlantic Basin could significantly reduce crucial strategic Atlantic Basin interests in the Middle East and the Caspian region, leaving China, India, and Russia to sort out the geopolitical headache of the New Great Game increasingly on their own. As soon as even a proto-Atlantic Basin energy system begins to deliver such energy security and other environmental and development benefits, a nascent Atlantic Basin consciousness could emerge and begin to spread.
3. The potential strategic advantages — in terms of energy, economic, and political security — of pursuing an Atlantic Basin strategy are clear: 1) a heightened relative geopolitical autonomy through geopolitical hedging and increased political and economic flexibility in relation to the extra-Atlantic world;

and 2) a strong stimulus for low-carbon transformation and the reduction of energy poverty.

Pathways, Barriers, Risks, and “Black Swans”

1. A number of potential future developments could have significant influence upon the development of an Atlantic Basin energy system. They include: (a) deepening cross-Atlantic investment in biofuels research and production; (b) increasing financing from North America and Europe (some through international financing mechanisms) to promote renewable energies, energy-efficiency improvements, and carbon-neutral land practices in the developing countries of the Atlantic Basin; (c) cross-investments, and technology and knowledge exchange on shale gas experiences and best-practices around the Atlantic Basin; (d) additional South African investment in GTL around the Atlantic Basin; (e) increased investment in Atlantic Basin oil and gas production; and (f) Increased LNG production in Atlantic Africa for consumption in the Atlantic Basin
2. However, a number of preconditions remain only weakly fulfilled, and a number of barriers (including some already mentioned to some degree above) continue to drag on the development of an Atlantic Basin energy system.
 - a. There is continued instability in the northern Atlantic economic and financial environment, which could reduce the economic growth across the Atlantic Basin, thereby diminishing the flow of energy-related investment from North to South.
 - b. Energy and carbon prices are not yet properly aligned in order to generate sufficient investment in the quantity (increased supply) and quality (lower carbon emissions) of Atlantic Basin energy supply, even despite the step-jump in oil prices over the last decade.
 - c. Economic and energy policy management and regulation, and not only in the developing countries, remains weak, ineffective, or distorting across much of the Basin. More flexible and fine-tuned energy policies, and more open but pragmatically regulated energy markets will be

needed around the basin. Energy nationalism (Venezuela, Argentina), institutional weaknesses (Mexico-Argentina, Nigeria-Angola), and transition problems (South Africa, Brazil) represent the principal challenges, particularly in the southern Atlantic.

- d. Furthermore, there are risks that the southern Atlantic oil boom will lead to the “Dutch Disease” and the “oil curse,” as well as to potential border conflicts. Ghana is now likely to become a relevant oil producer and exporter, with all the attendant energy, development, macroeconomic, and foreign policy implications. Although Ghana might be better equipped to deal with the challenge of the “resource curse” than its other West African neighbors, it will need to maintain strict policy vigilance in order to avoid the curse’s corrosive dynamics.
- e. Oil could be a looming “black swan” for Morocco, with enormous strategic implications, opportunities, and risks. The Moroccan government should develop a well-planned strategic response prior to any eventual discovery of oil in its own waters — especially in advance of an oil discovery in any waters it may still contest with other countries.
- f. Although the offshore oil industry is booming around the Atlantic Basin, and as the interpenetration of the equipment and services sectors across the southern Atlantic deepens and intensifies, the re-emergence of the Falklands/Malvinas sovereignty issue stands out as a potential geopolitical hurdle to further development of a southern Atlantic offshore oil ring and an Atlantic Basin energy system. These geopolitical tensions reveal the systems and governance deficits within the southern Atlantic. On the other hand, they also underline the enormous potential of the opportunities forgone as a result of this geopolitical brake upon the development of the energy systems of the region. The Falklands/Malvinas dispute, which diplomatically partially divides North from South, could even stimulate the formation of a southern Atlantic consciousness, perhaps to the detriment of any potentially wider Atlantic Basin system or framework.

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- g. The lack of a diplomatic or political framework of international relations within the Basin strong enough to sustain the shift of relative power from North to South currently under way makes it more difficult to resolve energy border disputes and other geopolitical frictions that periodically can arise within the Atlantic Basin. Such frictions might even nip in the bud any potential Atlantic Basin consciousness, framework, or system. The development of some kind of Atlantic Basin energy framework — or de facto collaborative community — could help resolve such disputes. Such a development, however, will depend of the vision of political leadership, and upon the technical and diplomatic capacities of countries from all across the broad Atlantic Basin.
 - h. There is currently no clearly identifiable Atlantic Basin consciousness. Potential lack of enthusiasm or concern in the northern Atlantic (where economic and financial concerns now take precedence over energy security and the reduction of carbon emissions) or even in the southern Atlantic, where international projection and loyalties have been developing across the global South (as opposed to with the North) hold back the development of such a regional consciousness. Without it, any Atlantic Basin diplomatic framework probably could not take shape, and any future Atlantic Basin energy system would remain relatively limited. If the much-touted Transatlantic Energy Council, a key pillar of the now nearly defunct Transatlantic U.S.–EU Summit architecture, has not come to much, why would Atlantic Basin energy collaboration be any different without the emergence of at least a nascent basin consciousness?

The Potentials of an Atlantic Basin and the Importance of an Atlantic Basin Energy System

1. There is much untapped potential in the notion of an Atlantic Basin and specifically in an Atlantic Basin energy system. Furthermore, any tangible, practical broadening and deepening of any Atlantic Basin energy system would offer the countries of the Atlantic world a number of strategic economic and geopolitical options.

2. The nations of the southern Atlantic could choose to pursue a new “comprehensive Atlanticism” (as opposed to pursuing “strategic integration” within the U.S.-EU relationship, or across the global South, or with the BRICS) in which “the interests of traditional and emerging powers around the Atlantic basin, north and south, align in ways that facilitate the development of wider Atlantic identities and strategies.”
3. An alternative, and probably inferior, strategic possibility for the countries of the southern Atlantic would be to pursue the vector of southern Atlantic regionalism. However, this would become the optimum strategy should the countries of the northern Atlantic fail to credibly demonstrate a commitment to some kind of rearticulated and global “Atlanticism.”²¹⁶
4. Development of an Atlantic Basin energy regionalism could also facilitate the economic transformation of many Atlantic countries, particularly in the southern Atlantic, through increased supply, improved energy access, and basin-wide synergistic effects stimulating the rollout of lower-carbon energy infrastructure and vibrant economic growth. By reducing the need for energy imports from Eurasia, an Atlantic Basin energy system would also enhance the geopolitical weight, autonomy, and flexibility of the countries of the basin.
5. Although a nascent Atlantic Basin energy system may, or may not, now exist, its further development could be critical to any such regional alignment of interests (Atlantic Basin or southern Atlantic) that might allow for wider Atlantic identities and strategies to emerge. Energy frequently serves as a geopolitical axis along which transnational integration competes with nationalist economic warfare. The mere existence of an Atlantic energy system, however incipient or uneven — to say nothing of its potential future framework or governance — would greatly facilitate the former. The absence of an Atlantic Basin energy system — or even its vulnerability to significant economic and political disruption — would help keep the door open, at least, for the latter.

216 See Ian Lesser, “Southern Atlanticism: Geopolitics and Strategy for the Other Half of the Atlantic Rim.” Washington, DC: The German Marshall Fund of the United States, Brussels Forum Paper Series, March 2010

6. For Atlantic Basin countries interested in exploring the potentialities of a reconfigured West, and in crafting a foreign policy that invests strategically in a rearticulated Atlantic, the question of the Atlantic Basin energy system is certainly relevant, if indeed not paramount.
7. Efforts to reinvigorate the traditional U.S.–EU relationship should also consider the usefulness, or even necessity, of incorporating the southern Atlantic — or at least, initially, its key rising national players. As the United States and the EU struggle to respond to recently emerged structural financial limitations at home — a response that has sacrificed progress, and even international leadership, on key energy and climate policy legislation — national players in the developing south of the Atlantic Basin are rapidly overcoming many of the structural impediments to growth and the reduction of poverty that they had experienced in the past, and are now pushing ahead with strategic transformations of their energy sectors in a much clearer fashion than the United States and, in some cases, even Europe. Their development paths may not be perfectly smooth, but their positive dynamics are more intense than in the North.
8. Recognition of this new structural reality from among the traditional actors in the U.S.–EU relationship in the North would build confidence and goodwill between the northern and southern actors of the Atlantic Basin, providing more credible incentive for the southern Atlantic countries — particularly Brazil, South Africa, and Morocco — to align more with the Atlantic Basin than with Eurasia and the Far East.
9. Nevertheless, each of these three emerging market countries of the Atlantic Basin (Brazil, Morocco, and South Africa) faces significant barriers to the low-carbon transformations of their energy economy and stubborn obstacles to the useful application of any Atlantic Basin concept (formally or informally) in their foreign and energy policy strategies in the future. However, an opportunity exists for actors in the northern Atlantic to seek partners from the southern part of the basin in the ongoing effort to eliminate energy poverty, reduce GHG emissions, and stimulate sustainable global growth. The

opportunity also exists for Brazil, South Africa, and Morocco to collaborate in efforts to deepen economic, energy, and political ties within the southern Atlantic. Such a development could generate a nascent Atlantic Basin consciousness in the South, laying the groundwork for a more balanced and productive Atlantic Basin in the future.

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