Natural Gas
Natural Gas
Private Sector Participation and Market Development

Finance, Private Sector, and Infrastructure Network

Introduction

Natural gas has the potential to play a large role in meeting the world's growing energy demand. There are abundant underdeveloped reserves of gas. Its competitiveness in power generation and other uses has increased dramatically. And it offers substantial environmental advantages over other hydrocarbon fuels. Not surprisingly, governments and investors alike are devoting much attention to gas.

This volume examines a range of issues relating to reforming the gas sector and developing gas markets. Among the most critical is creating an acceptable framework for private investment. Surveying reform across countries, the first two Notes show that there has been progress—though unevenly distributed—and that where it has occurred it has been followed by significant investment, greater efficiency, lower prices, and an expanded range of gas services. They also show that for most developing and transition economies the reform agenda—price liberalization, promotion of competition, transparent regulation, and privatization—is far from complete.

The Notes that follow examine the reform experience in countries ranging from those with well-developed gas industries and infrastructure to those whose gas industries are just getting started. In countries with a more mature gas sector a move to full market liberalization is possible (as in Argentina, the United Kingdom, and the United States), but has not always been pursued (as in Hungary, Poland, and Ukraine). Where the sector is young, different models may apply (as in Northern Ireland). Across all countries, however, strong government commitment to reform has proved essential to market development. Clear and early specification of a reform strategy and steps to maximize the potential for competition are critical to success. Lack of transparency and retention of state monopolies have invariably slowed the pace and postponed the benefits of gas development.

The last section in the volume reviews some of the commercial issues faced in expanding the role of gas—the challenges of developing and financing cross-border gas pipeline trade, and the difficulties of attracting investors to projects involving countries with high credit and currency risks. If these issues can be successfully addressed, the rewards will be substantial.

The Notes in this volume are part of a continuing series on oil and gas issues written by World Bank Group staff and invited outside authors and published under the auspices of the World Bank's Finance, Private Sector, and Infrastructure Network. Comments and suggestions are welcome.

CHARLES MCPHERSON
MANAGER
Contents

Natural Gas
Private Sector Participation and Market Development
Natural Gas Sector Trends

A Scorecard for Energy Reform in Developing Countries  link
Robert Bacon

Private Participation in the Transmission and Distribution of Natural Gas—Recent Trends  link
Ada Karina Izaguirre

Developing Gas Markets
Gas Sector Restructuring and Privatization—Lessons from Argentina, Brazil, Poland, Hungary, and Vietnam  link
Peter L. Law and Bent R. Svensson

Regulation in New Natural Gas Markets—The Northern Ireland Experience  link
Peter Lehmann

International Gas Trade—The Bolivia–Brazil Gas Pipeline  link
Peter L. Law and Nelson de Franco

Competition in the Natural Gas Industry—The Emergence of Spot, Financial, and Pipeline Capacity Markets  link
Andrei Juris

Natural Gas Markets in the U.K.—Competition, Industry Structure, and Market Power of the Incumbent  link
Andrei Juris

Development of Competitive Natural Gas Markets in the United States  link
Andrei Juris

Gas Reform in Ukraine—Monopolies, Markets, and Corruption  link
Laszlo Lovei

Trends and Markets in Liquefied Natural Gas  link
Rob Shepherd
Pricing of Gas Transport and Distribution

The 1996–97 Gas Price Review in Argentina

Andres Gomez–Lobo and Vivien Foster

Mitigating Political Risk

World Bank Guarantees for Oil and Gas Projects

Scott Sinclair

Mitigating Currency Convertibility Risks in High–Risk Countries–A New IDA Lending Approach

Karen Rasmussen

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Contents
A Scorecard for Energy Reform in Developing Countries

Robert Bacon

Only a handful of developing countries have fully reformed their energy sectors—oil, gas, and power. A World Bank survey of 115 developing countries shows that on average in mild–1998 just 39 percent of key reform steps had been carried out. Only the upstream oil and gas sector shows a substantially higher degree of reform, largely because of the need to facilitate concession agreements for high–cost exploration and production. Private participation in energy is also fairly limited, as is privatization of existing assets—especially in Sub–Saharan Africa and the Middle East and North Africa. There are large variations among countries in the number of reforms steps taken, with most reforms concentrated in a small number of countries. Reform is most advanced in Latin America and the Caribbean. In the great majority of countries little or no reform has been done.

The scorecard was produced by a project funded by the World Bank and United Nations Development Programme's Energy Sector Management Assistance Programme. The longer paper on which this Note is based is forthcoming and will be available from the World Bank at 202 458 2321 (telephone) or esmap@worldbank.org. The paper includes scorecards for each country.

### TABLE 1 ENERGY REFORM INDICATORS BY REGION, 1998

<table>
<thead>
<tr>
<th>Region</th>
<th>Power</th>
<th>Upstream oil and gas</th>
<th>Downstream gas</th>
<th>Downstream oil (refining)</th>
<th>Downstream oil (wholesale and retail)</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>East Asia and the Pacific</td>
<td>41</td>
<td>47</td>
<td>38</td>
<td>58</td>
<td>21</td>
<td>41</td>
</tr>
<tr>
<td>Europe and Central Asia</td>
<td>45</td>
<td>44</td>
<td>36</td>
<td>45</td>
<td>45</td>
<td>43</td>
</tr>
<tr>
<td>Latin America and the Caribbean</td>
<td>71</td>
<td>50</td>
<td>63</td>
<td>24</td>
<td>33</td>
<td>53</td>
</tr>
<tr>
<td>Middle East and North Africa</td>
<td>17</td>
<td>43</td>
<td>11</td>
<td>17</td>
<td>27</td>
<td>23</td>
</tr>
<tr>
<td>South Asia</td>
<td>50</td>
<td>50</td>
<td>50</td>
<td>44</td>
<td>27</td>
<td>46</td>
</tr>
<tr>
<td>Sub–Saharan Africa</td>
<td>15</td>
<td>59</td>
<td>31</td>
<td>24</td>
<td>20</td>
<td>32</td>
</tr>
<tr>
<td>All regions</td>
<td>34</td>
<td>49</td>
<td>38</td>
<td>35</td>
<td>32</td>
<td>39</td>
</tr>
</tbody>
</table>
Sector Reform Scores

The survey of energy reform covered the power, upstream oil and gas, and downstream oil and gas sectors (box 1). Oil and gas pipelines and power transmission were omitted from the survey if they had already been separated from the rest of the sector. For each sector the survey covered only countries that have the sector and where it has not been entirely under private ownership for the past ten years; sectors that have been under private ownership for ten years are not considered part of the current reform movement. The results are given separately for each sector because the coverage differs among them.

Energy sector reform requires a number of facilitating steps, but the final goal is to introduce private ownership where possible and competition in the parts of energy industries that are not natural monopolies, with monopolistic elements being regulated.

The average reform indicator for all sectors is around 35 percent, except for upstream oil and gas, where it is nearly 49 percent (table 2). These figures indicate that, at the global level, many

**BOX 1 SURVEY QUESTIONS AND METHODS**

The World Bank surveyed energy reform in 115 countries to see what steps had been taken and what milestones achieved in this process. The first four survey questions asked about reform steps that enable private capital investment in a sector that was previously owned by the state. The last two questions asked whether private capital had entered the sector. The six questions are:

1. Has the utility been commercialized and corporatized?
2. Has parliament completely passed a law that allows the energy sector to be unbundled or privatized in part or in whole?
3. Has a regulatory body that is separate from the utility and from the energy ministry started work?
4. Has the core state-owned utility been restructured?
5. Is there any private investment in greenfield sites, either in operation or under construction?
6. Has any of the public utility been privatized?

The questions about downstream oil activities differed slightly from those for power and upstream oil because refining was separate from wholesale and retail functions. For refining the survey asked about private greenfield investment, but for retail and wholesale functions it asked whether prices are freely set, since almost all countries have some private retail gasoline outlets.

All the survey questions could be answered yes or no, making it possible to give precise values to the number of steps taken. Each yes scored one and each no scored zero, giving a maximum of six for a sector when all the questions were answered positively. The number of steps actually taken, expressed as a percentage of this maximum, is termed the reform indicator.

For several reasons the data presented in this Note understate what
remains to be done:

The survey asked whether there was any private participation, so even a small asset or share sale would be counted as a yes and given the same weight as complete divestiture.

All countries were treated as equally important in the questionnaire, so different countries with some privatization received the same weight regardless of the size of the sector.

Some countries have many regions, so success in one region (for example, in one state in India) counts as success for the entire country. In reality, the other states may be far from reform.

The reform indicator was calculated for each sector, for each country, for the aggregate of the countries in the sample, and for each region.

### TABLE 2

**ENERGY REFORM STEPS BY SECTOR**

<table>
<thead>
<tr>
<th>Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sector and sample size</td>
</tr>
<tr>
<td>-----------</td>
</tr>
<tr>
<td>Power, 115 countries</td>
</tr>
<tr>
<td>Upstream oil and gas, 49 countries</td>
</tr>
<tr>
<td>Downstream gas, 55 countries</td>
</tr>
<tr>
<td>Downstream oil (refining), 57 countries</td>
</tr>
<tr>
<td>Downstream oil (wholesale and retail), 72 countries</td>
</tr>
</tbody>
</table>

n.a. Not applicable.

a. Though not among the six main reform steps for the other sectors, freeing retail prices is considered crucial to reform of downstream oil activities. Steps still have to be taken before the fullest gains from private involvement in the energy sector can be realized.

The higher level of reform activity in upstream oil and gas is significant because there is often fierce government opposition to private sector entry in this sector. But a distinguishing feature of upstream oil and gas activities is
that the cost of exploration and development, especially of offshore oil, can be very large, and the risks very great. In cases where the state cannot take on the financing burden, private finance is often recognized as essential and is allowed through the use of concessions. Such concessions may require that laws be changed and state enterprises restructured, but in few cases have countries been willing to privatize existing upstream oil and gas assets.

There is a logical sequence to reform steps if a country is working toward full private sector participation and competition, and the survey results were expected to show this pattern. First, the state company must be corporatized and commercialized. Next, a law permitting private entry must be passed. Then regulation must be implemented. After that the state enterprise should be restructured through vertical and horizontal separation. Private greenfield investment could then be allowed. Finally, existing assets should be privatized. Thus the first and most common step is corporatization and commercialization of the state enterprise, and the final and least common step is privatization of existing assets (see table 2). In power and upstream oil and gas a much larger percentage of countries have permitted private investment than have introduced formal regulation or restructured the industry. Such countries appear not to be preparing for privatization and the creation of competitive markets. Rather, they appear to be augmenting the existing system by admitting private investment on new sites, probably selling to the state enterprise through some type of contract. The small portion of countries that have privatized energy assets confirms this interpretation, especially for upstream oil and gas.

Comparing Reform across Countries

For the most part reform has spread very unevenly across countries, with upstream oil and gas experiencing the most even pattern (table 3). In power more than a third of the 115 countries in the sample had taken none of the six reform steps. The

<table>
<thead>
<tr>
<th>Sector</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power</td>
<td>42</td>
<td>15</td>
<td>16</td>
<td>12</td>
<td>8</td>
<td>10</td>
<td>12</td>
</tr>
<tr>
<td>Upstream oil and gas</td>
<td>5</td>
<td>4</td>
<td>7</td>
<td>15</td>
<td>12</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Downstream gas</td>
<td>12</td>
<td>12</td>
<td>8</td>
<td>6</td>
<td>7</td>
<td>8</td>
<td>2</td>
</tr>
<tr>
<td>Downstream oil (refining)</td>
<td>24</td>
<td>14</td>
<td>11</td>
<td>8</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td>Downstream oil (wholesale and retail)</td>
<td>32</td>
<td>21</td>
<td>9</td>
<td>10</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
</tbody>
</table>

n.a. Not applicable.

Note: This table shows that in power, for example, only twelve countries have taken all six steps, and fifteen have taken only one step.
TABLE 4
COUNTRIES IN EACH REGION TAKING KEY REFORM STEPS IN POWER

<table>
<thead>
<tr>
<th>Reform step</th>
<th>East Asia and the Pacific (9)</th>
<th>Europe and Central Asia (27)</th>
<th>Latin America and the Caribbean (18)</th>
<th>Middle East and North Africa (8)</th>
<th>South Asia (5)</th>
<th>Sub-Saharan Africa (48)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporatization</td>
<td>44</td>
<td>63</td>
<td>61</td>
<td>25</td>
<td>40</td>
<td>31</td>
</tr>
<tr>
<td>Law</td>
<td>33</td>
<td>41</td>
<td>78</td>
<td>13</td>
<td>40</td>
<td>15</td>
</tr>
<tr>
<td>Regulator</td>
<td>11</td>
<td>41</td>
<td>83</td>
<td>0</td>
<td>40</td>
<td>8</td>
</tr>
<tr>
<td>Independent power producers</td>
<td>78</td>
<td>33</td>
<td>83</td>
<td>13</td>
<td>100</td>
<td>19</td>
</tr>
<tr>
<td>Restructuring</td>
<td>44</td>
<td>52</td>
<td>72</td>
<td>38</td>
<td>40</td>
<td>8</td>
</tr>
<tr>
<td>Generation assets divested</td>
<td>22</td>
<td>37</td>
<td>39</td>
<td>13</td>
<td>40</td>
<td>4</td>
</tr>
<tr>
<td>Distribution assets divested</td>
<td>11</td>
<td>30</td>
<td>44</td>
<td>13</td>
<td>20</td>
<td>4</td>
</tr>
<tr>
<td>Reform indicator</td>
<td>41</td>
<td>45</td>
<td>71</td>
<td>17</td>
<td>50</td>
<td>15</td>
</tr>
</tbody>
</table>

Note: Numbers in parentheses are the number of countries in each region's sample.

10 percent most reforming countries accounted for 30 percent of the reform steps that had been taken. This pattern suggests that reform is not a uniform process, but rather that is proceeds rapidly when conditions are favorable—and does not even start when conditions are unfavorable.

Comparing Reform across regions

The country data were grouped by the world Bank's regional classifications to highlight the differences among regions. The results show that power reform is much more advanced in Latin America and the Caribbean than in other regions: 71 percent of the key reform steps have been taken, compared with 15 percent in Sub-Saharan Africa and 17 percent in the Middle East and North Africa (table 4). But even in Latin America and the Caribbean only 40 percent of countries have started to privatize existing generation or distribution assets—while in Sub-Saharan Africa the corresponding figure is just 4 percent.
TABLE 5
COUNTRIES IN EACH REGION TAKING KEY REFORM STEPS IN UPSTREAM OIL AND GAS

<table>
<thead>
<tr>
<th>Reform step</th>
<th>East Asia and the Pacific (5)</th>
<th>Europe and Central Asia (17)</th>
<th>Latin America and the Caribbean (8)</th>
<th>Middle East and North Africa (5)</th>
<th>South Asia (3)</th>
<th>Sub-Saharan Africa (11)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporatization</td>
<td>80</td>
<td>65</td>
<td>63</td>
<td>80</td>
<td>33</td>
<td>73</td>
</tr>
<tr>
<td>Law</td>
<td>60</td>
<td>65</td>
<td>63</td>
<td>60</td>
<td>67</td>
<td>91</td>
</tr>
<tr>
<td>Regulator</td>
<td>40</td>
<td>24</td>
<td>50</td>
<td>0</td>
<td>33</td>
<td>36</td>
</tr>
<tr>
<td>Restructuring</td>
<td>60</td>
<td>29</td>
<td>25</td>
<td>40</td>
<td>100</td>
<td>55</td>
</tr>
<tr>
<td>Concessions</td>
<td>40</td>
<td>65</td>
<td>63</td>
<td>80</td>
<td>67</td>
<td>91</td>
</tr>
<tr>
<td>Privatization</td>
<td>0</td>
<td>18</td>
<td>38</td>
<td>0</td>
<td>0</td>
<td>9</td>
</tr>
<tr>
<td>Reform indicator</td>
<td>47</td>
<td>44</td>
<td>50</td>
<td>43</td>
<td>50</td>
<td>59</td>
</tr>
</tbody>
</table>

Note: Numbers in parentheses are the number of countries in each region's sample.

TABLE 6
COUNTRIES IN EACH REGION TAKING KEY REFORM STEPS IN DOWNSTREAM GAS

<table>
<thead>
<tr>
<th>Reform step</th>
<th>East Asia and the Pacific (4)</th>
<th>Europe and Central Asia (27)</th>
<th>Latin America and the Caribbean (9)</th>
<th>Middle East and North Africa (6)</th>
<th>South Asia (3)</th>
<th>Sub-Saharan Africa (6)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporatization</td>
<td>100</td>
<td>59</td>
<td>56</td>
<td>50</td>
<td>100</td>
<td>33</td>
</tr>
<tr>
<td>Law</td>
<td>50</td>
<td>33</td>
<td>78</td>
<td>0</td>
<td>67</td>
<td>33</td>
</tr>
<tr>
<td>Regulator</td>
<td>25</td>
<td>41</td>
<td>78</td>
<td>0</td>
<td>33</td>
<td>33</td>
</tr>
<tr>
<td>Restructuring</td>
<td>25</td>
<td>30</td>
<td>56</td>
<td>17</td>
<td>67</td>
<td>33</td>
</tr>
<tr>
<td>Investment</td>
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<td>22</td>
<td>56</td>
<td>0</td>
<td>33</td>
<td>33</td>
</tr>
<tr>
<td>Privatization</td>
<td>0</td>
<td>33</td>
<td>56</td>
<td>0</td>
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<td>17</td>
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<tr>
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<td>38</td>
<td>36</td>
<td>63</td>
<td>11</td>
<td>50</td>
<td>31</td>
</tr>
</tbody>
</table>

Note: Numbers in parentheses are the number of countries in each region's sample.

The regional picture for upstream oil and gas is very different from that for power. The average indicator for all regions is around 50 percent, and for Sub-Saharan Africa it is nearly 60 percent (table 5). In African countries where there is upstream production there has been an almost universal willingness to allow private concessions, which are associated with the need for state oil companies to be corporatized and commercialized and laws...
permitting private entry to be passed. Still, only one Sub-Saharan country has been willing to privatize upstream oil and gas assets.

In downstream gas Latin America and the Caribbean has again seen the most activity, with all steps being taken equally often, including privatization (table 6). Other regions have done little

TABLE 7
COUNTRIES IN EACH REGION TAKING KEY REFORM STEPS IN DOWNSTREAM OIL (REFINING)

<table>
<thead>
<tr>
<th>Reform step</th>
<th>East Asia and the Pacific (4)</th>
<th>Europe and Central Asia (22)</th>
<th>Latin America and the Caribbean (11)</th>
<th>Middle East and North Africa (6)</th>
<th>South Asia (3)</th>
<th>Sub-Saharan Africa (11)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporatization</td>
<td>75</td>
<td>59</td>
<td>45</td>
<td>33</td>
<td>67</td>
<td>55</td>
</tr>
<tr>
<td>Investment</td>
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<td>18</td>
</tr>
<tr>
<td>Privatization</td>
<td>50</td>
<td>45</td>
<td>18</td>
<td>17</td>
<td>33</td>
<td>0</td>
</tr>
<tr>
<td>Reform indicator</td>
<td>58</td>
<td>45</td>
<td>24</td>
<td>17</td>
<td>44</td>
<td>24</td>
</tr>
</tbody>
</table>

Note: Numbers in parentheses are the number of countries in each region's sample.

TABLE 8
COUNTRIES IN EACH REGION TAKING KEY REFORM STEPS IN DOWNSTREAM OIL (WHOLESALE AND RETAIL)

<table>
<thead>
<tr>
<th>Reform step</th>
<th>East Asia and the Pacific (8)</th>
<th>Europe and Central Asia (26)</th>
<th>Latin America and the Caribbean (11)</th>
<th>Middle East and North Africa (5)</th>
<th>South Asia (5)</th>
<th>Sub-Saharan Africa (17)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporatization</td>
<td>50</td>
<td>50</td>
<td>36</td>
<td>40</td>
<td>60</td>
<td>29</td>
</tr>
<tr>
<td>Privatization</td>
<td>0</td>
<td>42</td>
<td>18</td>
<td>40</td>
<td>20</td>
<td>24</td>
</tr>
<tr>
<td>Free prices</td>
<td>13</td>
<td>42</td>
<td>45</td>
<td>0</td>
<td>0</td>
<td>6</td>
</tr>
<tr>
<td>Reform indicator</td>
<td>21</td>
<td>45</td>
<td>33</td>
<td>27</td>
<td>27</td>
<td>20</td>
</tr>
</tbody>
</table>

Note: Numbers in parentheses are the number of countries in each region's sample.

to allow private investment on greenfield sites and almost nothing to privatize existing assets.

The reform effort in refining is notably low in Sub-Saharan Africa, the Middle East and North Africa, and Latin America and the Caribbean (table 7). Thus in Latin America and the Caribbean there has been less enthusiasm for privatization of refining than for privatization of power, upstream oil and gas, and downstream gas. In Europe and
Central Asia, where many countries have domestic refining capacity, a large proportion have privatized these assets.

The downstream wholesale and retail oil sector is very different from the other sectors. Besides existing in every country, in some 37 percent of countries the sector had involved private participation for at least ten years. In countries where this had not been the case the willingness to privatize was generally low, especially in Latin America and the Caribbean and East Asia and the Pacific (Table 8). As with refining, many countries in Europe and Central Asia privatized wholesale and retail functions. In some regions downstream wholesale and retail oil activities appeared to be viewed as a strategic sector that the government was unwilling to sell, while in Europe and Central Asia governments have been willing to divest themselves of this underperforming sector. This contrasts with the pattern in the upstream oil and gas sector, where Latin America and the Caribbean has the highest proportion of privatization and all other regions have virtually no privatization.

TABLE 9
COUNTRIES THAT HAVE ALLOWED PRIVATE INVESTMENT THAT HAVE TAKEN OTHER REFORM STEPS

<table>
<thead>
<tr>
<th>Percent</th>
<th>Corporatization</th>
<th>Law</th>
<th>Regulator</th>
<th>Restructuring</th>
<th>Privatization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Countries with independent power producers</td>
<td>63</td>
<td>57</td>
<td>50</td>
<td>57</td>
<td>50</td>
</tr>
<tr>
<td>All countries</td>
<td>44</td>
<td>33</td>
<td>29</td>
<td>35</td>
<td>25</td>
</tr>
<tr>
<td>Upstream oil and gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Countries with concessions</td>
<td>74</td>
<td>79</td>
<td>38</td>
<td>50</td>
<td>18</td>
</tr>
<tr>
<td>All countries</td>
<td>67</td>
<td>69</td>
<td>31</td>
<td>43</td>
<td>14</td>
</tr>
<tr>
<td>Downstream gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Countries with private investment</td>
<td>80</td>
<td>67</td>
<td>67</td>
<td>67</td>
<td>60</td>
</tr>
<tr>
<td>All countries</td>
<td>60</td>
<td>40</td>
<td>40</td>
<td>35</td>
<td>27</td>
</tr>
<tr>
<td>Downstream oil (refining)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Countries with private</td>
<td>92</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
<td>62</td>
</tr>
<tr>
<td>All countries</td>
<td>54</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
<td>28</td>
</tr>
</tbody>
</table>

n.a. Not applicable.
Does Private Investment Encourage Other Reforms?

In the early days of reform one strategy advocated for the power sector was to encourage the entry of independent power producers. This approach was considered less problematic for government because it did not involve the sale of national assets or the immediate labor shedding that a private owner might require. It was hoped that independent power producers would set a good example for the rest of the sector and eventually force other players to become more efficient and privatize assets. If that were to happen the sector would ideally need a law permitting private entry and a regulator—even though independent power producers, when governed by long-term take-or-pay contracts, do not require either to operate successfully. The same argument applies to other energy sectors with respect to private entry into greenfield investment.

To test whether governments that were willing to allow private investment in new projects were also willing to undertake other reform steps, the relationship between these steps was calculated. For example, forty-three countries have independent power producers, and of these 57 percent have passed a privatization law (table 9). Among the complete power sample of 115 countries, thirty-eight (33 percent) had passed a privatization law. Thus countries that have admitted independent power producers have been more ready to take other reform steps.

In power, downstream gas, and refining countries that have allowed private investment are more likely to have taken other reform steps, including privatization of existing assets. The difference in the reform indicator between countries with

| TABLE 10 |
| REGIONS WITH PRIVATE INVESTMENT AND PRIVATIZATION OF ASSETS BY SECTOR |

Percent

<table>
<thead>
<tr>
<th>Sector</th>
<th>All regions</th>
<th>East Asia and the Pacific</th>
<th>Europe and Central Asia</th>
<th>Latin America and the Caribbean</th>
<th>Middle East and North Africa</th>
<th>South Asia</th>
<th>Sub-Saharan Africa</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Power</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Independent power producers</td>
<td>40</td>
<td>78</td>
<td>33</td>
<td>83</td>
<td>13</td>
<td>100</td>
<td>19</td>
</tr>
<tr>
<td>Privatization</td>
<td>25</td>
<td>33</td>
<td>41</td>
<td>50</td>
<td>13</td>
<td>40</td>
<td>6</td>
</tr>
<tr>
<td><strong>Upstream oil and gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Concessions</td>
<td>69</td>
<td>40</td>
<td>65</td>
<td>63</td>
<td>80</td>
<td>67</td>
<td>91</td>
</tr>
<tr>
<td>Privatization</td>
<td>14</td>
<td>0</td>
<td>18</td>
<td>38</td>
<td>0</td>
<td>0</td>
<td>9</td>
</tr>
<tr>
<td><strong>Downstream gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Private investment</td>
<td>27</td>
<td>25</td>
<td>22</td>
<td>56</td>
<td>0</td>
<td>33</td>
<td>33</td>
</tr>
<tr>
<td>Privatization</td>
<td>27</td>
<td>0</td>
<td>33</td>
<td>56</td>
<td>0</td>
<td>0</td>
<td>17</td>
</tr>
<tr>
<td><strong>Downstream oil</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Does Private Investment Encourage Other Reforms? 12
How Far Has Reform Gone?

Commercialization and corporatization, legal reform, regulation and restructuring are all crucial to energy reform. But by themselves these four steps do not bring about the improvements sought. To secure those improvements, countries must also take the next two steps: allowing private investment and privatizing assets. Only 24 percent of countries have privatized existing energy assets, and only 40 percent have allowed new private investment in the sector (table 10). Though there are large regional differences, even in the two regions with the most reform experience—Latin America and the Caribbean and Europe and Central Asia—just 36 percent of countries have allowed existing energy assets to be privatized. In East Asia and the Pacific, the Middle East and North Africa, South Asia, and Sub-Saharan Africa this figure is around 15 percent. In all regions except Europe and Central Asia there is a notable difference between the willingness to permit private participation in greenfield sites and the willingness to privatize existing assets.

Robert Bacon (rbacon@worldbank.org), Oil and Gas Division

Private Participation in the Transmission and Distribution of Natural Gas—Recent Trends

Ada Karina Izaguirre

The 1990s have seen a significant increase in private participation in the transmission and distribution (transport) of natural gas in developing countries. Until 1990 private participation in the construction and ownership of natural gas transport facilities in these countries was limited to a few isolated cases. The increasing participation of the private sector in gas transport has resulted mainly from a growing demand for new gas transport facilities coinciding with a growing consensus in favor of private participation in infrastructure. The increasing demand for gas transport facilities has been driven by the strong growth in energy demand, discoveries of important natural gas fields, and concerns about the environment. Private involvement in the construction or ownership of gas transport infrastructure has been prompted not only by the acceptance of private participation in infrastructure, but also by public sector budget constraints.
Between 1990 and 1997 twenty-six developing countries introduced private participation in the transmission and distribution of natural gas (figure 1). This Note, which draws on the World Bank's PPI Project Database, provides an overview of the patterns and trends in the projects in these countries. The database covers only projects that transport natural gas to end users; captive pipelines owned by private upstream gas producers and condensate operations are not included (box 1). The form of private participation varies—ranging from greenfield projects to export natural gas from Algeria to Europe or to create a natural gas plant.

The World Bank's Private Participation in Infrastructure (PPI) Project Database covers private participation in infrastructure in developing countries. The database compiles information on privately owned or managed electricity, telecommunications, transport, water, and natural gas transmission and distribution projects. This Note focuses on the natural gas projects that reached financial closure between 1990 and 1997, surveying regional trends in and types of private participation.

**Figure 1**
Developing Countries with Transmission and Distribution Projects with Private Participation, 1990–97

**BOX 1**
**PPI PROJECT DATABASE: PROJECT CRITERIA AND DATABASE TERMINOLOGY**

*Database coverage*

To be included, a project must have reached financial closure and directly or indirectly serve the general public.

The sectors covered are electricity, natural gas, telecommunications, transport, and water.

The period covered is 1984–97.

The natural gas sector includes two segments: transmission and distribution. The database excludes liquefied natural gas plants, movable assets, incinerators, stand-alone solid waste projects, and small projects such as windmills.

The database covers developing countries, as defined and classified by the World Bank, in East Asia and the Pacific, Europe and Central Asia, Latin America and the Caribbean, the Middle East and North Africa, South Asia, and Sub-Saharan Africa.
Definition of private participation. The private company must assume operating risk during the operating period or assume development and operating risk during the contract period. In addition, the operator must consist of one or more corporate entities with significant private equity participation that are separate from any government agency.

Definition of a project unit. A corporate entity created to operate infrastructure facilities is considered a project. When two or more physical facilities are operated by the same corporate entity, all are considered as one project.

Project types

Divestitures. A private consortium buys an equity stake in a state−owned enterprise. The private stake may or may not imply private management of the company.

Greenfield projects. A private entity or a publicprivate joint venture build and operate a new facility. This category includes build–owntransfer and build–own–operate contracts as well as merchant power plants.

Operations and management contracts. The private entity takes over the management of a stateowned enterprise for a given period. This category includes management contracts and leases.

Operations and management contracts with major capital expenditure. A private consortium takes over the management of a state−owned enterprise for a given period during which the private entity also assumes significant investment risk. This category includes buildtransfer–operate, build–lease–transfer, and buildrehabilitate–operate–transfer contracts as applied to existing facilities.

Definition of financial closure. For greenfield projects and for operations and management contracts with major capital expenditure, financial closure is defined as the existence of a legally binding commitment of equity holders or debt financiers to provide or mobilize funding for the project. The funding must account for a significant part of the project cost, securing the construction of the facility.

For operations and management contracts, there must be a lease agreement or a contract authorizing the commencement of management or lease service. For divestitures, the equity holders must have a legally binding commitment to acquire the assets of the facility.

Sources

World Wide Web
Commercial databases
Specialized publications
Developers and sponsors
Regulatory agencies

Contact

The database is maintained by the World Bank's Private Participation in Infrastructure Group. For more information contact Mina Salehi at 202 473 7157 or msalehi@worldbank.org.
distribution market in Mexico to the privatization of existing assets in Argentina and Hungary. During 1990–97 the private sector took on the operations or construction risk of seventy–seven natural gas transport projects, with investments totaling US$18.9 billion (figures 2 and 3).

The diverse development levels of the natural gas sector in developing countries raise policy issues for private participation that are quite different from those in other infrastructure sectors. Except for countries in Europe and Central Asia and a few in Asia and Latin America, most developing countries have limited or no gas resources or transport facilities (figures 1 and 4). Some countries have promoted private involvement in existing facilities, while others have relied on the private sector to establish new gas networks. A third group of countries has no gas network—public or private.

Although private participation in natural gas transport projects has increased significantly in recent years, it remains limited. Still, four trends are evident:

Divestitures and greenfield projects are more common than operations and management contracts.

Stand–alone transmission and distribution projects are more common than integrated (transmission, distribution, and sometimes production) projects.

Export–oriented projects are starting to emerge.

Projects are concentrated in certain regions and countries.

**Divestitures and Greenfield Projects Dominate**

Of the total investment in private gas transport projects, about 56 percent has gone to the fortyeight divestitures and 40 percent has gone to the twenty–seven greenfield projects (figure 5). As might be expected, divestitures have occurred in countries with well–developed pipeline networks, while greenfield projects have occurred mainly in countries with little or no transport infrastructure for natural gas.

Operations and management contracts with significant capital expenditure have been rare in gas transport facilities, particularly relative to the water sector. By 1997 only two operations and management contracts involving significant capital expenditure had been signed. One was for the rehabilitation and operation of the natural gas transmission system in Kazakhstan. The other was for the expansion and operation of a small distribution system in Turkey. Operations
Figure 3
Investment in Private Natural Gas Transport Projects in Developing Countries, 1990–97

Figure 4
World Gas Resources Trillions of cubic meters
Figure 5
Investment in Private Natural Gas Transport Projects in Developing Countries by Type of Project, 1990–97

and management contracts (without capital expenditure) and lease contracts have not featured as a form of private participation in the natural gas sector.

**Investments Focus on Stand-alone Projects**

Most private investment in gas transport projects has been concentrated in vertically deintegrated facilities. Of the total invested, 64 percent has been captured by the twenty-two projects involving the operation or construction of transmission facilities (figure 6 and table 1). Most of these projects have been in Latin America and the Caribbean (twelve projects). Stand-alone distribution facilities, in turn, have been concentrated in Europe and Central Asia (twenty-five) and Latin America and the Caribbean (twenty-one). The predominance of stand-alone projects might be explained by increasing attempts by government to create more competitive markets for natural gas supply, building on experiences in the United Kingdom and the United States.

There have been just five integrated-utility gas projects involving private participation, and most have been in Europe and Central Asia (Latvias Gaze in Latvia, Eesti Gas in Estonia, Lietuos Dujo in Lithuania, Gazprom in the Russian Federation, and Petronas Gas in Malaysia). Private involvement in these projects has fallen short of full private ownership.

**Export-oriented Pipelines Emerge**

Another feature of the private participation in natural gas has been the implementation of large export-oriented pipeline projects. The natural gas industry requires access to gas fields, which may or may not exist in a country. Thus the development or expansion of a domestic gas industry has required international gas trade. Five private pipeline projects of this type, representing total investment of US$4 billion, reached financial closure between 1990 and 1997: the Yadana gas pipeline from Myanmar to Thailand, the Maghreb gas pipeline from Algeria to Europe, the Gas–Andes pipeline from Argentina to Chile, and the sections of the Yamal gas pipeline in Belarus.
and Poland. Among those projects, the Argentine–Chilean gas pipeline was the first to introduce natural gas into a country (Chile). The project, developed by a fully private consortium, is part of a business plan to develop Chile’s natural gas industry.

More cross-border projects are expected to be implemented in the next few years. In addition to the Bolivia–Brazil pipeline now close to completion (see page 33), there are plans for international transmission pipelines in most regions. Examples include proposals to develop pipelines from Turkmenistan to Turkey, from Indonesia to Singapore, from Bangladesh and Oman to India, from Argentina to Chile and Uruguay, and from Egypt to Israel and other countries in the Middle East.

**Investments Reflect a Regional and National Concentration**

Investment in private natural gas transport projects is concentrated in Latin America and the Caribbean. Thirty-three projects have reached financial closure in the region, mobilizing investments of US$9.3 billion, or 49 percent of the total.

![Figure 6](image)

*Figure 6*
Investment in Private Natural Gas Transport Projects in Developing Countries by Segment, 1990–97

<table>
<thead>
<tr>
<th>TABLE 1</th>
<th>PRIVATE NATURAL GAS TRANSPORT PROJECTS IN DEVELOPING COUNTRIES BY SEGMENT, 1990–97</th>
</tr>
</thead>
<tbody>
<tr>
<td>Segment</td>
<td>Number of projects</td>
</tr>
<tr>
<td>Distribution</td>
<td>50</td>
</tr>
<tr>
<td>Transmission</td>
<td>22</td>
</tr>
<tr>
<td>Transmission and distribution</td>
<td>5</td>
</tr>
</tbody>
</table>
investment in private projects in the sector between 1990 and 1997 (table 2). Countries in Europe and Central Asia have also been active in opening their natural gas utilities to the private sector, awarding thirty-three projects representing total investment of US$3 billion during the same period. Private sector activity in other regions has been limited to a few projects.

As in the electricity and water sectors, a few countries capture most projects and investments.3 The

<table>
<thead>
<tr>
<th>Region</th>
<th>Total investment in projects with private participation (1997 US$ millions)</th>
<th>Number of projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>East Asia and the Pacific</td>
<td>3,131</td>
<td>5</td>
</tr>
<tr>
<td>Europe and Central Asia</td>
<td>3,087</td>
<td>33</td>
</tr>
<tr>
<td>Latin America and the Caribbean</td>
<td>9,274</td>
<td>33</td>
</tr>
<tr>
<td>Middle East and North Africa</td>
<td>3,271</td>
<td>2</td>
</tr>
<tr>
<td>South Asia</td>
<td>75</td>
<td>3</td>
</tr>
<tr>
<td>Sub-Saharan Africa</td>
<td>40</td>
<td>1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>18,876</strong></td>
<td><strong>77</strong></td>
</tr>
</tbody>
</table>

Source: PPI Project Database.

The top five countries ranked by investment in projects involving private participation accounted for 33 percent of all projects and almost 67 percent of total investment in 1990–97 (table 3). Among those five countries, two (Argentina and Algeria) captured about half of the total investment in the sector. The list of top five countries changes significantly when the countries are ranked by number of projects, although the high concentration of projects in a few countries remains (table 4). These changes in ranking can be partly explained by divestiture approaches taken by the Czech Republic and Kazakhstan, which privatized their natural gas utilities through mass (voucher) privatization schemes.

A breakdown of investment by project reveals a similarly high concentration of resources in few projects. The top five projects accounted for more than 40 percent of total investment in the sector in 1990–97 (table 5). Three of these projects were in Argentina, representing around 37 percent of the investment in divestitures. The Maghreb gas pipeline from Algeria to Europe, in turn, accounted for 45 percent of the investment in greenfield projects.
Latin America and the Caribbean

The private sector has been involved in the transportation of natural gas in the six Latin American countries (Argentina, Bolivia, Brazil, Chile, Colombia, and Mexico) that have developed a local gas industry. In most of these countries private participation in natural gas projects has been part of broader sector reform that has usually included the establishment of new regulatory frameworks and the vertical separation of the sector into its three basic business units (production, transmission, and distribution). New legal frameworks in these countries have also required mandatory open access to pipelines for third parties in order to promote competition in natural gas markets. Argentina and Chile have been the most market–oriented reformers in the region, creating competitive market structures, transferring investment decisions to the market, and allowing full private ownership of transmission and distribution assets.

Most natural gas reforms in Latin America have also been a component of broader energy reforms. Six of the seven countries started to reform their natural gas sectors at the same time that they were liberalizing their electricity sectors.

Latin American countries have chosen different forms of private participation depending on the initial development of their natural gas facilities. Countries with a fully developed network, like Argentina, or with main transportation assets, like Bolivia and Brazil, have opted for divestitures. Fifteen of the seventeen divestitures in the region are located in these three countries. Other countries with limited or no transportation networks—such as Chile, Colombia, and Mexico—have focused on constructing facilities through greenfield projects. The fifteen greenfield projects in the region are all in these three countries. More projects are expected in these countries, and in others such as Uruguay and Peru, as the private sector leads the drive to make natural gas available to all major urban centers.

Europe and Central Asia

Private participation in natural gas transport in Europe and Central Asia has focused on the privatization of existing assets. Of the thirty–three private gas transport projects in the region, twenty-nine have been divestitures, accounting for 59 percent of the investment in the region. The privatization mechanism has differed across countries. Hungary sold controlling stakes to private consortia, reflecting the priority it puts on improving the efficiency and reliability of existing assets. The Czech Republic, Kazakhstan, and the Russian Federation opted for mass privatization programs. And Estonia, Latvia, and Lithuania privatized their natural gas companies by creating joint ventures with Gazprom, Russia's partially privatized and vertically integrated natural gas company.

Although private participation in natural gas activities has increased significantly in the region, the new investment that has come with divestitures has been minimal. The main reasons appear to be low retail natural gas tariffs, which have impaired the financial viability of natural gas utilities, and underdeveloped legal and regulatory frameworks.

East Asia and the Pacific

East Asian countries can be considered in two groups. The first group comprises countries with existing gas transport facilities, such as the Republic of Korea, Malaysia, and Thailand. In these countries (except Korea) natural gas transmission and distribution is still a business reserved for the public sector. This situation mirrors that in these countries' electricity sectors, which remain dominated by state–owned enterprises. The second group comprises countries with limited or no gas transport facilities, such as China, Indonesia, and the Philippines.
Private participation in the region has been restricted to a few greenfield projects, mainly for the construction of new transmission pipelines (three projects) and one small distribution system. The only divestiture, which was partial, took place in Malaysia and took the form of a public offering aimed at raising funds rather than transferring control to the private sector. This situation is expected to change as privatization proposals in Korea and greenfield projects in Indonesia and the Philippines are implemented.

### TABLE 3
**TOP FIVE DEVELOPING COUNTRIES BY INVESTMENT IN PRIVATE NATURAL GAS TRANSPORT PROJECTS, 1990–97**

<table>
<thead>
<tr>
<th>Country</th>
<th>Total investment in project with private participation (1997 US$ millions)</th>
<th>Number of projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>Argentina</td>
<td>6,284</td>
<td>10</td>
</tr>
<tr>
<td>Algeria</td>
<td>2,570</td>
<td>1</td>
</tr>
<tr>
<td>Malaysia</td>
<td>1,436</td>
<td>2</td>
</tr>
<tr>
<td>Hungary</td>
<td>1,324</td>
<td>7</td>
</tr>
<tr>
<td>Colombia</td>
<td>938</td>
<td>5</td>
</tr>
<tr>
<td>Total</td>
<td>12,551</td>
<td>25</td>
</tr>
</tbody>
</table>

*Source: PPI Project Database.*

### TABLE 4
**TOP FIVE DEVELOPING COUNTRIES BY NUMBER OF PRIVATE NATURAL GAS TRANSPORT PROJECTS, 1990–97**

<table>
<thead>
<tr>
<th>Country</th>
<th>Number of projects</th>
<th>Total investment in projects with private participation (1997 US$ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Argentina</td>
<td>11</td>
<td>6,284</td>
</tr>
<tr>
<td>Kazakhstan</td>
<td>11</td>
<td>a</td>
</tr>
<tr>
<td>Mexico</td>
<td>10</td>
<td>604</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>8</td>
<td>a</td>
</tr>
<tr>
<td>Hungary</td>
<td>7</td>
<td>1,324</td>
</tr>
<tr>
<td>Total</td>
<td>47</td>
<td>8,211</td>
</tr>
</tbody>
</table>

*a.Both countries privatized their gas utilities through mass privatization, so there is no divestiture revenue.*

*Source: PPI Project Database.*

posals in Korea and greenfield projects in Indonesia and the Philippines are implemented.
South Asia

Private participation in South Asia has been limited to three small greenfield projects to develop or expand distribution facilities in India. But if

<table>
<thead>
<tr>
<th>Project</th>
<th>Country</th>
<th>Total investment (1997 US$ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maghreb Gas pipeline from Algeria to Europe</td>
<td>Algeria/Morocco</td>
<td>2,556</td>
</tr>
<tr>
<td>Transportadora de Gas del Sur</td>
<td>Argentina</td>
<td>1,939</td>
</tr>
<tr>
<td>Petronas Gas Sdn Bhd</td>
<td>Malaysia</td>
<td>1,265</td>
</tr>
<tr>
<td>Transportadora de Gas del Norte</td>
<td>Argentina</td>
<td>1,070</td>
</tr>
<tr>
<td>Distribudora de Gas Metropolinata</td>
<td>Argentina</td>
<td>969</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>7,798</td>
</tr>
</tbody>
</table>

*Source:* PPI Project Database.

recent proposals to privatize natural gas facilities in India and to build cross-border greenfield transmission pipelines from Bangladesh or Oman to India are implemented, there should be a significant increase in private participation in the region over the next few years.

Middle East and North Africa

Private participation in natural gas in the Middle East and North Africa has focused on one export-oriented greenfield project (the Maghreb gas pipeline in Algeria) and one domestic pipeline (Tunisia). But private participation in the region should increase over the next few years if projects awarded in Egypt to provide natural gas to areas with no supply and other export-oriented pipeline proposals are implemented.

Sub-Saharan Africa

Private participation in natural gas in Sub-Saharan Africa has been limited to one greenfield project, the CI–11 gas pipeline in Côte d'Ivoire. There is also a proposal for the Nigerian government and Chevron to build a West African gas pipeline. The limited activity in the region is explained mainly by the lack of gas reserves and the limited transport infrastructure in the region (except in South Africa). Small domestic markets in most countries have also limited the development of gas distribution infrastructure.
Conclusion

Private participation in the transmission and distribution of natural gas has increased significantly in recent years and should continue to expand. Experiences in Argentina and Chile show that the private sector can play the leading role in developing or expanding the natural gas industry. As in other infrastructure sectors, the key role for the government is to establish an appropriate enabling environment, including well-defined policies and a sound regulatory framework. The growth in privately financed and operated export projects promises to bring the economic and environmental benefits of natural gas to a larger number of countries.

1 All dollar amounts are in 1997 U.S. dollars. The PPI Project Database records total investment, not private investment alone, in infrastructure projects involving private participation. There were no natural gas projects involving private participation in developing countries in 1990 and 1991.


3 See Gisele Silva, Nicola Tynan, and Yesin Yilmaz, "Private Participation in the Water and Sewerage Sector—Recent Trends" (Public Policy for the Private Sector, September 1998), and Ada Karina Izaguirre"Private Participation in the Electricity Sector" (Public Policy for the Private Sector, December 1998).


5 Most natural gas distribution facilities in Korea are owned by longestablished investor–owned utilities.

Ada Karina Izaguirre (aizaguirre @worldbank.org), Consultant, Private Participation in Infrastructure Group

Gas Sector Restructuring and Privatization
Lessons from Argentina, Brazil, Poland, Hungary, and Vietnam

Peter L. Law and Bent R. Svensson

Since the mid–1990s international oil and gas companies have shown strong interest in developing gas markets in World Bank client countries. Sometimes the focus is on developing local gas markets for industry and power generation, and sometimes on exporting gas to a neighboring country. In most cases, however, the government is strapped for cash and needs to attract private investors to realize capital–intensive gas projects. More often than not, the starting point is an oil and gas sector where fuel prices are distorted, dominated by a single vertically integrated state monopoly that essentially regulates itself, with weak oversight from a government ministry.

This Note reviews experiences in five countries that have embarked on gas sector reform—Argentina, Brazil, Poland, Hungary, and Vietnam. Each case study reflects a gas market at a different stage of development, with varying dependence on gas imports and a range of approaches to legal and sector restructuring. The Note focuses on the development of each sector’s structure and the legal and regulatory framework, and on the strength of the new government institutions set up to implement and monitor the new framework.

Argentina

In 1992 Argentina became the first country in Latin America to pursue wholesale restructuring and privatization of its natural gas sector. Today Argentina consumes some 20 billion cubic meters of gas a year, most of which is
domestically produced. The gas market is mature, accounting for nearly half of primary energy consumption. Argentina has imported gas from Bolivia since the 1970s, and it now exports gas to Chile.

Legal Framework

The legal framework for the energy sector contains a set of acts specific to downstream gas services that are totally separate from those dealing with hydrocarbon exploration and production and other energy forms.

The 1992 Gas Law formed the basis for the privatization of the state-owned Gas del Estado and established the framework for the new industry structure, tariff setting, and network access (figure 1). The law took less than two years to design and approve—a relatively short time for reform of this magnitude. At the time it was passed the law was unique among developing countries for its transparency and procompetitive stance. The law mandates private ownership and industry unbundling and avoids conflicting interests through restrictions on cross-ownership. Gas distributors and producers cannot own a majority shareholding in transmission. Distribution companies have regional monopolies but do not have exclusive rights to supply large consumers. Transmission companies have no regional monopolies and cannot buy or sell gas. The law requires that third parties have access to gas transmission lines, and while it sets no restrictions on the import of natural gas, an enterprise wishing to export gas is required to obtain government authorization.

The Gas Law also created Enargas to regulate the downstream gas sector. Funding and staffing needs were initially underestimated. The annual budget, US$8.5 million in the first year, doubled after two years. With the exception of a US$5 million start-up budget from the government, Enargas has from the beginning been funded "independently" by levies on the privatized

Figure 1
Gas Sector Reform in Argentina
industry. This setup helps to minimize the risk of political interference.

The prices of gas and competing fuels were raised to international levels before privatization, and the principles of fuel price liberalization were embodied in the gas legislation.

**Sector Restructuring**

At the time the reform began Gas del Estado had a monopoly in the downstream gas sector, operating all of the country's transmission and distribution lines. It bought gas from Yacimientos Petroliferos Fiscales (YPF), the state oil and gas production company and by far the country's largest producer. The government opted to restructure (unbundle) the industry before privatization.

Gas del Estado was reorganized into two transmission companies (both of which were obliged to offer services on a nondiscriminatory basis) and eight regional distribution companies. Buenos Aires was divided into two distribution areas served by both transmission companies, thereby introducing some competition in supply. The six (now seven) other distribution companies cover the rest of Argentina. While these distribution companies have a right of first refusal for the construction of new networks in their service areas, consumers can bypass distribution companies if cheaper gas is available.

Downstream privatization was achieved in 1992 by a simultaneous sell−off of the entire downstream gas infrastructure through international competitive tender. Restrictions were placed on the number of units that could be awarded to winning bidders—for example, a winning bidder could not own both transmission companies or more than two distribution companies. The process proved highly successful, attracting fifty−five bids from international consortia and raising some US$2 billion—much more than had been expected. Privatization created a highly competitive downstream gas sector where private investors have to carefully assess their business risks.

Since privatization an additional US$2 billion has been invested in industry expansion, and further investments are planned for gas exploration and production and for new export pipelines. The main issues in the sector today are considered second−generation issues, such as how to ensure a properly functioning secondary market for transmission capacity.

One important issue remains unresolved, however. Before its privatization YPF controlled more than 80 percent of Argentina's natural gas reserves and production, and it still controls around half. Thus YPF retains a dominant position in upstream gas supply, where true competition has yet to be achieved.

**Brazil**

In 1995, in a step to allow private participation in the energy sector, Brazil's constitution was changed to remove the monopoly of Petrobras, the state oil and gas company. Since then reforms have proceeded quickly. The gas sector is poised for transformation from a small industry that consumes just 4 billion cubic meters of gas a year, derived from a few domestic oil and gas fields, to a major industry sustained by large gas imports. Gas imports will start in 1999 with the completion of a US$2 billion gas import pipeline from Bolivia. Even though the pipeline is not yet complete, its full capacity—11 billion cubic meters a year—has been booked by shippers. A second major import pipeline from Argentina and liquefied natural gas imports are being planned.
Legal Framework

A Hydrocarbon Law was passed in 1997 to open the sector to private participation and competition. The law was designed and implemented in less than two years.

The law covers upstream and downstream oil and gas development (except gas distribution). For upstream activities it defines the legal framework for awarding exploration concessions. For downstream activities it includes provisions for negotiated third-party access to oil and gas infrastructure, and allows private companies to import and export hydrocarbons (subject to authorization by the regulatory agency) and gain access to the market.

The law includes a three-year transition period to achieve full deregulation of fuel prices and does not place restrictions on cross-ownership in the gas chain. In 1994, well before gas reform began, the government had started raising the prices of the main competing fuels (fuel oil and liquefied petroleum gas) and removing subsidies. The timetable to achieve full deregulation included in the Hydrocarbon Law assured potential investors in the gas sector that price risks were small. By the time the Hydrocarbon Law was passed and the Bolivia–Brazil pipeline was becoming a reality, competing fuel prices were close to international levels.

The law created the Hydrocarbon Sector Regulatory Agency to regulate the sector. The agency's staff is expected to increase from about 150 today to 350 by the end of the transition period in 2000. The agency does not yet have an independent funding source. During 1998 the agency's budget, approved by Congress, was about US$120 million, but only half of this was actually spent. The agency will soon have new and more “independent” sources of revenue from bonus payments made by the industry after the bidding for new exploration areas.

Designing and implementing downstream regulations has been very time consuming, and it may have been better to create separate agencies to oversee upstream exploration and development and downstream service activities. The key future challenges for the regulatory agency are to ensure smooth harmonization and implementation of regulation at the state and federal levels and to introduce real competition in a sector still dominated by Petrobras.

Sector Restructuring

Until the Hydrocarbon Law was passed, Petrobras had a legal monopoly on the import, production, and transmission of natural gas and petroleum for all of Brazil. Individual states were responsible for distribution. Today majority private ownership is allowed in all areas of the natural gas business, but because of its traditional role, Petrobras will likely remain dominant in the production and transmission of oil and gas for some time. This dominance will ease when Petrobras reduces its shareholding in the Bolivia-Brazil pipeline company as stipulated by the Brazilian government. Moreover, Petrobras is taking only a minority role in gas distribution, an activity that has largely been sold off to foreign and domestic private companies.

Brazil has been successful in attracting private investment for the Bolivia–Brazil pipeline and for the Rio de Janeiro gas distribution company, as well as for several smaller distribution companies.

Poland

Poland has a well-established natural gas infrastructure, distributing some 10 billion cubic meters a year to towns and villages throughout the country. Less than half the gas originates from domestic production; the rest is imported by pipeline from Russia. Gas accounts for only 8 percent of primary energy in a sector dominated by indigenous coal, but there is good potential for increasing the share of gas, particularly for heat and power generation. Domestic production is declining, however, and increasing dependence on imported gas is anticipated.
Poland expects to access most of its additional requirements through its participation in the Europol gas pipeline. The pipeline, now under construction, will form part of a new arterial route for Russian supplies to Western Europe. Poland also recently agreed to import modest volumes from North Sea suppliers, which represents a first step toward supply diversification.

**Legal Framework**

Two key laws govern Poland's energy sector—the Geological and Mining Law (1994) and the Energy Law (1997). The Geological and Mining Law deals with upstream exploration and exploitation of oil and natural gas (as well as other minerals). Under this law the government has provided attractive petroleum exploration and development contract terms, and after a slow start, several foreign companies have signed exploration licensing agreements. Still, the best prospective areas have been reserved for the Polish State Oil and Gas Company.

The Energy Law is a downstream law designed to deal with the transmission, distribution, and trading of so-called network fuels, including electricity, natural gas, liquid fuels, and district heat. The basic principles set out in the law are separation of the policymaking, regulation, and ownership functions of the state, price liberalization, demonopolization, privatization, and introduction of third-party access. The law took about five years to design and be approved by Parliament—an extended period that reflects the complexity of political consensus-building in Poland and the long debate within Poland and the European Union (which Poland soon expects to join) on how competition should be introduced in the gas and electricity sectors.

The Energy Law is very general, avoids detail, and is widely applicable across the network fuels. Comprehensive regulation specifying the details needed to implement the law is under preparation. Without this, it will not be possible to regulate the sector and private companies will lack incentive to invest.

The law places no restrictions on cross-ownership of infrastructure. It mandates third-party access only for domestic producers, a move intended to keep powerful foreign gas companies such as Gazexport (the export arm of Russia's Gazprom) at a safe distance from the market.

The Energy Law stipulates that there will be a transition period of two years (until 2000), after which energy prices should be set by competition or, in the case of natural monopolies, by regulation. Since 1990 Poland has raised industrial gas prices to Western European levels (and residential gas prices somewhat above industrial prices), but until the Energy Law was passed, potential investors considered government control of gas prices to be a major risk.

The Energy Law created the Energy Regulatory Agency to regulate retail tariffs of network fuels, a daunting task given the breadth of its jurisdiction and the technical complexity of Poland's energy networks. The agency has now issued some 2,000 licenses to energy sector enterprises, a tremendous achievement—especially since the agency has just 30 staff members (out of an anticipated 200). The agency's next major task is to begin the process of approving tariffs for the electricity and heating sectors, followed by approval of tariffs for the gas sector in 2000.

**Sector Restructuring**

The Polish State Oil and Gas Company is a vertically integrated company responsible for natural gas imports, domestic oil and gas production, and gas transmission, storage, and distribution. It holds a de facto monopoly on these activities by virtue of its dominant position in the market. Although the company is the only producer of natural gas in Poland, this might change if foreign exploration efforts are successful.
The company is currently being restructured: noncore drilling and service companies are being privatized, and the new industry structure is expected to separate hydrocarbon prospecting and production, gas transmission, and gas distribution. But restructuring has been slow and barriers to private entry have been high, resulting in almost no private investment in downstream natural gas development. However, Poland is in the preaccession phase for integration with the European Union (EU) and will ultimately have to open its gas markets in line with other EU member countries and adjust its policies to comply with the EU Directive on the Internal Market Liberalization for Natural Gas.

**Hungary**

Hungary was the first Eastern European country to attempt reform and privatization of its gas sector. In the early 1990s gas consumption was around 11 billion cubic meters a year, with half produced domestically and half imported from Russia. Given the good potential for expanding the market, privatization was expected to attract serious interest from Western European gas companies. In addition, a new pipeline between Hungary and the Western European gas network was planned (and completed in 1996), offering the prospect of diversifying supplies and arranging gas import deals with Western European suppliers.

Today the main players in the Hungarian gas sector are the majority privately owned company Magyar Olaj−és Gázipari Rt (MOL)—which deals with hydrocarbon exploration and production, refining, and natural gas transmission, storage, and wholesale distribution—and six majority privately owned regional gas distribution companies that serve some 2 million customers.

**Legal Framework**

The two key acts governing the gas sector are the Mining Act (1993) and the Gas Act (1994). The Gas Act covers downstream gas activities and established the Hungarian Energy Office to regulate the sector. The energy office is responsible for proposing changes in gas prices, though final approval rests with the government. The Gas Act stipulates that gas supply (transmission and distribution) should be subject to a license but includes no specific requirement for suppliers to offer third-party access to transport facilities.

Price reform came quite late in the reform effort. In 1995 a ministerial decree on gas pricing stipulated that from 1997 gas prices should be set according to a formula intended to provide an 8 percent regulated rate of return to MOL and the distribution companies, with annual price revisions until 2001. The pricing mechanism was based on a price cap that included three main components: actual input costs, expected cost changes due to such factors as inflation and exchange rate variation, and measures for efficiency improvements. The new pricing system was intended to rationalize gas prices, which were heavily subsidized in the early 1990s (particularly for households), and entitled consumers to compensation if a company's rate of return rose above a certain level.

Since privatization, efforts to implement the new pricing system have encountered political obstacles, and price increases to the residential sector have been lower than was stipulated by the price review rules. MOL has argued that it has not been allowed to recover the full cost of imported gas, and raising gas prices remains a politically charged issue.

**Sector Restructuring**

In 1991 MOL was established as a joint stock company by consolidating the numerous enterprises previously held under the Hungarian National Oil and Gas Trust. Since then shares in MOL have been sold to domestic and foreign investors. But Hungarian privatization law stipulates that the state must retain at least 25 percent of the company plus a "golden share." This will ensure that the state continues to exert significant control.
Today MOL is Hungary's only producer of natural gas and only licensed wholesale distributor. It owns all high-pressure gas transmission lines, is not required to offer third-party access, and has a right of first refusal to purchase all natural gas imports. Although MOL has no legal monopoly on gas exploration and production, for all practical purposes it holds a de facto monopoly in all gas activities except distribution.

The distribution entities were restructured into joint stock companies, and in 1992 the government decided to sell the majority of shares in these companies to foreign investors. Institutional reform had barely started, however, and the government had neither committed to resolving the gas pricing issue nor implemented a proper regulatory framework. In the end the government revoked the invitation to bid for private tenders and the first attempt at privatization failed. The second attempt was made in 1996 after regulations on gas pricing were in place. The six regional distribution companies were offered for sale based on a 50 percent sale of shares plus one share, with a golden share retained by the state. Private investors had to commit to expanding the distribution networks and transferring their management skills to the company. In return the buyers would retain an exclusive right to supply the areas covered by the distribution systems. This second attempt at privatization was highly successful. International competition attracted twenty-four prequalified foreign bidders and raised some US$500 million, or twice the companies' book value.

Since privatization MOL has gained a firm foothold in the gas distribution business and now holds a minority shareholding in five of the six regional distribution companies. However, Hungary expects to be among the first Eastern European countries to join the European Union, which will require MOL to offer third-party access to its transmission lines to comply with the EU directive on gas.

**Vietnam**

Vietnam's gas industry is starting from scratch. The first move was in 1995, when associated gas from the White Tiger offshore oil field was landed onshore. In 1998 about 1.0 billion to 1.5 billion cubic meters of this gas was consumed by two power stations near Ho Chi Minh City. A project for exploiting nonassociated gas from two fields in the Nam Con Son basin is now being negotiated between a consortium of private producers and Petrovietnam, with about 3 billion cubic meters a year of gas production from the first phase planned to be used for power generation. Vietnam's hydrocarbon potential is much larger than these numbers suggest, however. Prices for petroleum fuels are at international levels, and domestically produced coal is priced close to this level.

**Legal Framework**

The Petroleum Law was passed in 1993, followed in 1996 by an implementation decree. Both deal with the exploration, development, and production of oil and gas. However, all upstream activities are assigned exclusively to Petrovietnam, the government enterprise authorized to conduct petroleum operations and enter into petroleum contracts. The Petroleum Law states that petroleum contracts can be in the form of production sharing contracts or joint ventures with private companies, and specifies model contract provisions. There is no legislation for downstream petroleum operations such as gas transmission, gas processing, and gas distribution.

Although the Petroleum Law sets up a new agency (State Management of Petroleum Operations) as the regulating entity for the oil and gas sector, the government is leaning heavily on Petrovietnam to perform the regulatory functions instead. Thus there is a potential conflict of interest.
Sector Structure

Petrovietnam receives associated gas at no cost and transports it onshore through its pipeline. The gas is consumed by Electricity of Vietnam, the state power monopoly, but a number of independent power producers are involved in negotiations for power generation contracts. The government has appointed Petrovietnam as an exclusive gas trader to initiate and develop the gas market in Vietnam. This move creates a risk of high costs, inefficiently allocated resources, and a slowdown in gas market development. It will also discourage investors from investing in the downstream gas industry.

Because of the lack of downstream legislation, the basic agreements for developing the Nam Con Son basin—including gas prices, infrastructure access, and rights and obligations—will initially be incorporated into the contracts between private producers, transporters, the state company that will purchase the gas, and the government. But this situation is not ideal. It would have been better if regulations for gas transmission and distribution licenses, the setting and approval of gas transmission tariffs, the definition of the third-party access rules, and technical standards had been in place. Such regulations would increase transparency, reduce the perceived risk by potential investors, and facilitate speedy development of the gas market.

Lessons

The case studies show that the legal framework for gas may range from separate laws for upstream and downstream operations to a single law covering both or even an umbrella law encompassing petroleum and electricity as well as gas. The best arrangement is separate laws for the upstream and downstream sectors because their roles are so different. These laws should be supported by regulations, licenses, and contracts, including the detailed commercial, technical, and environmental regulations needed to implement the laws. Implementation and monitoring should be supported from the outset by an adequately funded and staffed regulatory institution. The regulator should be financed by the industry to ensure funding independent of government.

Of the countries studied, Argentina comes the closest to best practice. Argentina introduced separate and detailed upstream and downstream laws and a well-designed regulatory framework before privatization—an approach that proved attractive to foreign investors. Vietnam, by contrast, lacks such a legal and regulatory framework, and investments in upstream activities began with production sharing contracts before the Petroleum Law was passed. With no regulatory framework in the downstream sector, there is a significant risk that negotiations will be delayed and downstream developments slowed.

Argentina’s restructuring and unbundling of the industry before privatization was also important, not only for successful privatization but also for the highly competitive industry that resulted. Reform transformed the Argentine gas industry overnight—from a public monopoly to a very competitive private industry. There were two key reasons for this outcome: the government was committed to privatization, and detailed legislation was introduced aimed at making the gas sector highly competitive. Poland and, to some extent, Hungary show that competition and privatization can be held back if a traditional integrated monopoly remains even after a new legal and regulatory framework has been put in place. Countries starting from scratch can avoid this market dominance or monopoly problem.

The case studies support the need to liberalize gas prices early in the reform process. The first privatization attempt in Hungary failed largely because of the government’s failure to produce a clear pricing policy—in contrast with the successful experience in Argentina.

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Regulation in New Natural Gas Markets—
The Northern Ireland Experience

Peter Lebmann

So far gas market liberalization has generally occurred in mature markets—particularly where much of the pipeline system has already been laid, as in Argentina, Britain, and the United States. In these cases a competitive structure is appropriate. In new markets, however, it may be difficult to introduce a competitive regime from the outset, and a different approach and form of regulation, such as a period of exclusive licenses, may be needed. In 1997 the Northern Ireland authorities awarded Phoenix Natural Gas an exclusive license for a limited period to develop a new gas market from scratch in the greater Belfast area. This Note explains the rationale for a period of exclusivity and describes Northern Ireland's approach to gas market regulation.

The Northern Ireland authorities had been eager to develop a natural gas market, both for environmental reasons and to make the province more attractive to foreign investors. Their effort was triggered by the conversion to natural gas of a power plant in Northern Ireland, with commissioning in 1996. The plant was owned by British Gas (now BG), and the gas is transported from Britain by a subsea pipeline. This pipeline provided an opportunity to deliver natural gas to homes and industry.

To take up this opportunity, a license for natural gas for the greater Belfast area was granted to Phoenix Natural Gas in a tender limited to only one other candidate. Phoenix was originally a 100 percent subsidiary of BG, though Keyspan Energy now has a 24.5 percent shareholding. Phoenix was granted a combined license for transport and supply, but different approaches were used for the two activities. An exclusive transport license lasts twenty years, but competition in supply will be allowed after only two to eight years.

Northern Ireland contains 600,000 households, with just over 250,000 in the greater Belfast area.

The economics of supplying gas to areas outside Belfast are difficult, though better opportunities may develop. Indeed, in a new gas industry it can be argued that the initial development license should be granted only for part of a region or country. In that case it may be best to develop the network as a series of regional franchises. That way, two or more licensees will be well placed to compete in each other's areas once the industry matures.

Monopoly in Transportation

The authorities accepted British Gas/Phoenix's argument that a long (twenty−year) transportation monopoly period was needed to attract an investor into the market. The necessary investments appeared to British Gas/Phoenix to be fairly marginal. Major marketing risks stemmed from having to displace coal, liquefied petroleum gas, and oil in the residential market and from the dependence of Phoenix on the decisions of a single body, the Northern Ireland Housing Executive, the public housing authority that owns more than a quarter of the houses in greater Belfast. There were also substantial technical and financial risks. The authorities decided that all these risks would be compounded if multiple infrastructure licenses were granted.

The authorities also agreed with British Gas/Phoenix that a single license would have other advantages. A single developer is more likely to develop an optimal, well−designed "backbone"network (avoiding, for example, multiple pipes and wires running down the same street). And a single developer is easier to deal with in terms of granting approvals, planning traffic, making contingency plans, and providing local authority support services.
Development Obligations

One of the authorities' primary goals was to secure the construction of an extensive natural gas pipeline system in Belfast. Thus investment obligations were a key part of the license. Several challenges arise when an investment program is expected of an exclusive licensee: how to ensure that the investment takes place, what sanctions to put in place if it does not, and how to deal with unforeseen circumstances.

The license requires Phoenix to complete its network in twelve years and to perform the work in each of Belfast's twelve districts in a specific order, within a specified timeframe. Moreover, a pipeline must run within 50 meters of 90 percent of the homes in each district. This was a much more detailed blueprint than Phoenix would have liked. Phoenix argued that it already had major sunk investments—in medium- and high-pressure pipelines—and so had the necessary commercial incentives to connect up the maximum load. The detailed blueprint created a risk that Phoenix will fail to meet its obligations. Two safeguards for Phoenix reduce but do not eliminate the risk:

The regulator can agree to changes in the order and dates of pipeline construction if there are good reasons for doing so.

Phoenix does not have to lay pipes past housing that the Northern Ireland Housing Executive had not converted to, and does not intend to convert to, natural gas.

If Phoenix does not meet its obligations, it will lose its exclusive license in the districts where it fails. Thus other companies could then be granted transportation licenses.

Transportation Charges

From the outset Phoenix has maintained separate charges for the use of the transport network by gas suppliers and for the supply of gas to final customers. Until competition is introduced, the transport charge will simply be a transfer price between Phoenix's distribution and supply businesses.

Both Phoenix and the authorities recognized that the price to final customers would have to be kept low for many years to persuade customers to switch to gas and that the overall costs of supplying gas would be dominated by the transport charges. Thus the debate over pricing focused on the transport charges; the supply prices were less contentious.

Standard approaches to setting transport charges are not appropriate for a new industry. The regulatory asset base starts from zero, changes rapidly, and is unpredictable. If charges are based on a return on assets, they would be exceptionally high at the outset (because of low utilization) and would change sharply from year to year. Thus it was decided to set transport charges at a level that is expected to provide an 8.5 percent real pretax return on cash flows over twenty years, with calculations based on forecast capital and operating costs, sales levels, and mix of sales. Phoenix considered this return rather low given the risks involved in the project. But there was some upside from the prospect of additional transport revenue after the initial twenty-year license period. The big question mark was the enormous uncertainty about all the forecasts. To address this uncertainty, it was agreed that there would be a reforecast every five years, with one possible additional forecast in the initial five-year period. Under these reforecasts the previous five years will be "water under the bridge"—that is, Phoenix will retain any gains and bear any losses if developments differ from what was forecast. Thus there are incentives for efficient and rapid market development. However, prices for the remaining period of the license would be adjusted in light of changes in the forecasts so that the net present value over the remaining period, given the new forecasts, would be the same as in the original net present value calculations.
One of the most controversial issues in the negotiations over transport charges was how to deal with changes in the distribution of gas sales among market segments and with the effects of such changes on costs and average prices. In addressing these matters the authorities wanted to prevent excessive profits for Phoenix, but also to provide incentives for rapid development of the network and market.

**Competition in Supply**

In a mature utility industry it is generally desirable to separate the transport business and the supply business, as there is different scope for competition and different competitors in the two sectors. In a developing industry, however, too strict a separation is undesirable. For example, the transport arm and the supply arm should plan an integrated rollout of the network to avoid major cost inefficiencies. That process involves information sharing and cooperation that might be unacceptable in a mature industry. Moreover, the cost allocations between infrastructure and marketing are blurred in the early days of a new industry.

Phoenix will face competition in supply in domestic and small industry markets (less than 2.2 million kilowatt−hours a year) in late 2004. Given that customers are being connected gradually over the eight−year exclusive license period, the average monopoly supply period for these customers will be four to five years. The monopoly period is shorter for larger industrial customers—from two to three years, with each district opening up to competition on a rolling basis.

The scope for competition may be limited given the small or nonexistent margins between transport and supply charges for many years. Still, Phoenix wanted an initial exclusivity period. The company was concerned that potential competitors would protest and that the authorities would take action if competition did not develop when it was permitted on paper. In the end the exclusivity periods agreed on were quite short—partly because the rest of the United Kingdom has competitive gas markets.

**Prices to final Customers**

A key challenge for the new gas industry is to win customers who are using competing fuels. The gas industry sometimes argues that it needs neither regulation nor gas−to−gas competition because there is strong competition between fuels. In a mature market with many gas customers, interfuel competition may need to be supplemented, especially in the residential market. But where a gas industry is being established, the industry's argument is valid.

Thus in Northern Ireland there is no regulation of gas prices to consumers, other than rules barring discrimination, for the first five years of the license. After that the regulator can introduce a price formula if he decides that customers' interests are not adequately protected by competition between fuels or within the gas market. This regulation applies only to consumers using less than 2.2 million kilowatt−hours a year; larger industrial customers are not subject to regulation of final prices.

The license sets out extremely broad principles for determining prices to customers if and when regulation is introduced. Moreover, there is a provision for a ruling by the Monopolies and Mergers Commission if the regulator and licensee cannot agree on prices.

**Cooperative Approach to Regulation**

The former regulator for electricity in Northern Ireland has become the joint gas and electricity regulator. But for several reasons the common adversarial approach to regulation is inappropriate in the new gas market. The uncertainty and pace of change mean that the ground rules will change rapidly—both sides need to recognize this. The lack of an asset base and the absence of "entrenched"high operating costs will also affect the
regulator's approach. In any case the normal regulatory battle—where the regulator wants low prices and the company wants high profits—will likely be replaced in the early years by a major shared objective: both sides want rapid penetration of the market. Furthermore, at the initial stages the fledgling industry will be a small or medium-size company and should not be burdened by unnecessarily high costs of funding the regulator's office, staffing a big regulatory affairs team, and funding inquiries from the Monopolies and Mergers Commission.

**Conclusion**

A lack of good precedents and credible competing offers made negotiations over the gas license unusually difficult in Northern Ireland. For good reasons, the approach taken to choosing the licensee was partly but not fully competitive. In some circumstances a more competitive process might be better. Still, the license that emerged may be useful for anyone working on the regulation of new gas industries.

In the two years since license discussions were concluded, Phoenix has completed the initial development of its network, meeting all regulatory targets and overcoming some inevitable difficulties. Moreover, Phoenix's gas prices have been lower than was anticipated.

Still, the market has posed some tough challenges. Competing fuel prices have been low (especially for oil), and threatened competitors, especially in residential markets, have fought back. The Northern Ireland Housing Executive, which had needed to demonstrate impartiality between fuel suppliers, has only recently announced that natural gas is the preferred fuel. As a result fewer of the executive's properties have been refurbished with gas than was expected. There has also been a shortage of appliance retailers and, more important, qualified installers.

It is still early days, but so far it has been the market rather than regulation that has had the major impact on the development of the Northern Ireland gas industry.

This Note has been prepared with the help of Gearoid Lane, Chris Murray, and Martin Plackett of Centrica, United Kingdom.

1 The European gas directive, which provides separately for emerging markets, recognizes this.

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**International Gas Trade—**

**The Bolivia–Brazil Gas Pipeline**

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The Bolivia–Brazil natural gas pipeline will transport natural gas more than 3,000 kilometers and cost US$2.1 billion to construct. Despite the large benefits for both Bolivia and Brazil and the involvement of reputable private partners, the perceived risks and complexities of this large project made financing it a challenge: the pipeline links supply in one country to a potential market in another, neither country has a record of independent regulation or economic fuel pricing, and the pipeline will be the first major gas infrastructure project involving the private sector in Brazil, where the natural gas market is underdeveloped and distribution infrastructure still very limited. This Note describes the factors that shaped the project, the way the financing came together, and the role the pipeline will play in liberalizing...
the Brazilian hydrocarbon sector.

When the pipeline project started to get off the ground in the early 1990s, the Brazilian hydrocarbon sector was dominated by government owned entities and prices were heavily regulated. At the federal level the oil and gas company Petrobras, the main player in the project, still had a monopoly on exploration, exploitation, refining, and maritime and pipeline transportation. Natural gas distribution was reserved for stateowned distribution companies, although petroleum distribution was open to foreign investors. Prices were equalized across regions, and the prices of liquefied petroleum gas (LPG) and fuel oil were subsidized. For Petrobras exploiting Brazil's modest natural gas reserves had been secondary to producing oil, and the share of natural gas in the energy market in the early 1990s was a mere 2 percent. Petrobras had introduced natural gas only in 1988, supplying small quantities to the existing São Paulo distribution network as associated gas from local oil fields. But with Brazil forecasting strong growth in energy demand, natural gas gained appeal as a means to offset increasing dependence on more expensive fuels. Meanwhile, Bolivia needed to find a new market for gas exports. The country had been exporting gas by pipeline to Argentina since the 1970s, with these export sales representing some 80 percent of Bolivia's total gas production, but new discoveries in Argentina gave notice that this was no longer tenable. The idea for natural gas trade between Bolivia and Brazil had been around since the 1930s, and in 1990 the two governments decided to give a gas export pipeline another serious look. After a preliminary feasibility study the two state monopolies, Petrobras in Brazil and Yacimientos Petrolíferos Fiscales Bolivianos (YPFB) in Bolivia, signed a gas sales contract in 1993.

**Private Investors Emerge**

Neither government was in a position to fund the pipeline project. As a first step to raise private finance, Petrobras embarked on a series of roadshows in 1994 to choose private equity partners for a new pipeline company on the Brazilian side. Petrobras ultimately selected the BTB consortium, comprising British Gas, Tenneco (now El Paso Energy), and Broken Hill Proprietary, to form the Brazilian transport company (Transportadora Brasileira Gasoduto Bolivia–Brasil, S.A. [TBG]). This company, with an initial 51 percent ownership by Petrobras, would

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**Figure 1**
The Bolivia–Brazil Natural Gas Pipeline
own the Brazilian part of the pipeline. However, the private partners began to signal to the government that fair access to downstream markets and market-based pricing policies would be important for the realization of the project—policies in line with those recommended earlier by the World Bank to the Brazilian government as key for the development of the hydrocarbon sector. In late 1995 an amendment to the Brazilian constitution removed the Petrobras monopoly, subject to an implementation law that was approved by Brazil's Congress in August 1997.

On the Bolivian side an agreement of association was reached between Enron and YPFB that included the development of the Bolivian section of the pipeline. YPFB was being prepared for capitalization and sale by international tender. A hydrocarbon law passed in 1996 committed Bolivian reserves to the export project and defined a diminished (but still critical) role for YPFB as the aggregator and shipper of future gas exports to Brazil. The capitalization of YPFB followed shortly after, and two private exploration and production companies and one oil and gas transportation company eventually won the international competitive tender. The Bolivian transportation company, Gas Transboliviano S.A. (GTB), was formed for the gas export project as a private joint venture among Enron, Shell, and Bolivian pension funds.

The project structure allowed a degree of crossborder ownership by each sponsor group, and special committees were formed with representation from all sponsors to resolve technical and financial issues and ensure cross-border harmonization of the project. This feature proved effective in helping to speed up project development.

**A Financing Plan Takes Shape**

In 1997 the project still lacked a firm financing plan. The project required a large, bulky, up-front investment with a gradual buildup of tariff revenues, and a final gas price that would provide incentives for a speedy uptake of gas by potential customers—industrial users and power plants. Market soundings had indicated a lack of capacity for long-term commercial funding. Commercial debt would be high cost with short maturities (eight to ten years) because of perceived Brazilian country risk, regulatory risk, and supply risks, resulting in debt service difficulties and a final gas price that could severely limit market penetration during the critical initial years. (Commercial lenders perceived some supply risks, since known Bolivian reserves were only sufficient to meet 80 percent of the gas sales contract. But in the World Bank's view the risks were likely to be small because the capitalization of YPFB had attracted some US$1 billion of private capital for further exploration and development.)

In 1997 the World Bank and its multilateral counterparts, convinced that both countries were serious about opening their hydrocarbon sector...
sectors to competition and private participation, decided to appraise the project on the understanding that transmission tariffs (and private investor rates of return) would be regulated to ensure that any benefits of extended maturities resulting from their loans and guarantees would be passed on to final consumers. A World Bank analysis showed the project to be economically viable. The analysis also showed it to be the best of several alternatives, including using different pipeline routes from Bolivia, constructing a pipeline from Argentina to Brazil, and constructing large gas−fired power plants in Bolivia and transporting the power to Brazil using highvoltage transmission lines. (The final pipeline route was selected to minimize environmental impact, and the project includes measures to protect the interests of indigenous people living near the pipeline; box 1.)

On the Brazilian side multilateral lending and partial credit guarantees offered the prospect of longer loan maturities and a gas price just right to penetrate the market. Thus the World Bank agreed in December 1997 to provide a direct loan of US$130 million and to continue preparing a partial credit guarantee of US$180 million to TBG. Other multilaterals, including the Inter−American Development Bank, provided financing totaling US$380 million. The multilateral financing covered 40 percent of the financing requirements as senior debt, Petrobras provided another 40 percent sourced from bilateral agencies, and the equity sponsors provided the rest.

On the Bolivian side only 20 percent of financing was available from shareholder equity. With the Bolivian government unprepared to provide sovereign guarantees, little progress was being made to close the financing gap. The Brazilian government, realizing that this threatened to delay the project until a new government was elected, urged Petrobras to quickly seek a solution. Petrobras responded through two mechanisms. First, it agreed to finance a fixed price turnkey construction contract for the Bolivian section of the pipeline, with repayment to be made through the waiver of future transportation fees. Second, it agreed to prepurchase part of the uncommitted upside capacity of the pipeline on both sides of the border, an arrangement that became known as the transport capacity option.

Who Takes the Risks?

Petrobras bears most of the project risk on both sides of the border. YPFB will collect gas from the producers, and the gas will be transported to the border under a ship−or−pay contract with GTB (figure 2). Here, Petrobras will take ownership of the gas for delivery to the five Brazilian state gas distribution companies under similar transportation arrangements with TBG.

The supply risk on the Bolivian side falls on YPFB. But this risk is small because of additional supply likely to become available from new discoveries in southern Bolivia and possibly northern Argentina. The biggest risk lies in the market in Brazil. Four of the five distribution companies are newly created and need to construct new gas distribution networks. Moreover, gas will have to

<table>
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<tr>
<th>Box 1 Protecting Social and Environmental Interests</th>
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<td>Pipeline construction activities must follow a detailed environmental management plan that sets standard construction techniques and social procedures to minimize any negative impact. The indigenous people residing in the pipeline's area of influence have been encouraged to participate in decisions that could affect them in any way. To protect the natural habitats, the local environmental protection agencies have been strengthened. And in view of the possibility that the pipeline project could stimulate future exploration activities in Bolivia, the project includes measures to ensure that any such activities will comply with the best environmental practices.</td>
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The arrangements for implementing the project's social and environmental standards are being overseen by a sponsors committee with responsibility for coordinating all environmental issues relating to the pipeline in both countries. The committee is supported in the field by an environmental inspection consulting firm, which determines whether all the environmental protection provisions are being met. In addition, an environmental auditor will carry out independent audits of the project's environmental and social compliance. Finally, an ombudsman reporting directly to the World Bank and the other multilaterals was appointed to ensure effective liaison between the project, local or regional government agencies, and civil society (including nongovernmental organizations), to monitor implementation of the social and environmental compensation programs as well as respond to concerns raised by civil society.

Moreover, through its turnkey construction contract, Petrobras takes the construction risk on the Bolivian side. And if the pipeline in Brazil is not built on time, it is Petrobras that will incur financial penalties payable to YPFB and the distribution companies.

Toward Sector Liberalization

The size and scope of the pipeline give it the leverage to play a key role in opening the Brazilian hydrocarbon sector to competition and private participation. The project and accompanying policy reforms will establish the principles of unbundling and transparent pricing in transactions between gas supply, transportation, and distribution. The pipeline will help promote interfuel competition in Brazil by allowing a large increase in gas supply and the policy framework will open the gas sector to more players by introducing the principles of third-party access.

During the project preparation stage it was still unclear to what extent Brazil's hydrocarbon sector would be opened to competition, as the hydrocarbon law was not passed until later. The World Bank therefore sought to include good practice policy principles relating to open access, ownership, and pricing in the authorization agreement between the government of Brazil and TBG that sets out the parameters under which the pipeline will eventually operate. These policies include nondiscriminatory third-party access, the adoption of distance-related transmission tariffs for the upside capacity of the pipeline, and the requirement that TBG would act only as a gas transporter and not engage in gas trading or up-stream or downstream cross-ownership.

Although Petrobras will be the dominant shareholder of the Brazilian transportation company for a transition period, the Brazilian government has agreed with the World Bank to eventually maximize private participation in the project. To initiate this too quickly would risk unraveling the many complex project agreements already reached and fail to maximize the value of the Petrobras shares. The government will therefore submit a plan for eventual reduction of Petrobras's shareholding in a way that will ensure the best chances for commercial success.

As part of the agreements reached with the World Bank, the Brazilian government has devel-
oped a plan to phase out fuel price subsidies and deregulate petroleum product prices within a three–year transition period (from August 1997). The concept of distance–based transport tariffs, a departure from the traditional pricing mechanisms, will encourage use of the best fuel supply option in each area of Brazil.

Open access to transmission systems, combined with increased private participation in upstream development, will be a major force in controlling extraction costs and increasing supplies of domestic gas in Brazil. It will ultimately lead to wider choices for consumers, allowing large consumers to negotiate directly with producers and importers for the best commercial terms.

**Implementing the Project**

Because of the enormous construction effort and tight deadlines entailed by the pipeline project, the sponsors decided to offer construction packages for international competitive bidding on the basis of individual construction spreads, allowing contractors to bid for single or multiple spreads. This approach would ensure a good number of qualified domestic bidders capable of mobilizing substantial resources—and the lowest overall price. The Bolivian section (about 500 kilometers) was offered as a single spread, the trunkline from the border to São Paulo (1,500 kilometers) as six spreads, and the southern leg (1,100 kilometers) as five spreads. Each of these sections attracted between ten and twenty bids from international construction companies, sometimes in association with regional companies, and final prices were some 25 percent less than the original construction estimates. These benefits of transparent competitive bidding should be passed on to final consumers through lower transport tariffs and more competitive gas prices. The construction of the main trunkline to São Paulo was completed on schedule in December 1998, and the southern leg is expected to be completed in October 1999.

The financial closing of the project occurred in December 1998 with the signing of the loan agreements between the project sponsors and the multilaterals, although the loans had been approved a year earlier. Because of the commitment shown by the multilaterals, project sponsors had felt confident enough to start the procurement process for equipment in June 1997, well in advance of financial closing.

Although construction of the Bolivia–Brazil pipeline is not yet complete, the project has given enormous stimulus to efforts to develop the gas market in Brazil and to exploration efforts in Bolivia and Argentina. Other project sponsors plan to construct a second gas import pipeline from Argentina to Porto Alegre, Brazil.

When construction of the Bolivia–Brazil pipeline began, no third–party shippers came forward to purchase the upside transport capacity. So, in an effort to ensure full utilization of the pipeline and in anticipation of the development of the gas market's potential, Petrobras purchased the pipeline's upside capacity. But the new Brazilian Hydrocarbon Regulatory Agency (Agencia Nacional do Petrolo, or ANP) will require Petrobras to resell this capacity to third parties if these parties can demonstrate their commitment to an imminent and realizable project. And as the pipeline expands (through construction of pipeline loops and new compression), third parties will be able to book transport capacity.

**Conclusion**

The financing of the pipeline project has led to a highly dynamic situation in Brazil, with a small public sector quickly being transformed into a privately oriented gas industry of major significance in Latin America.

The financing of the pipeline has relevance for other regions too. Many prospective international gas pipeline projects are under consideration—projects in Central and South Asia, and projects proposing pipelines from Russia to China and from Turkey to Eastern Europe. Given the large investments required, the main challenge is to design financing schemes that work. There are few blueprints to draw on. The World Bank can
play a key transitional role in such projects. But there needs to be demonstrable commitment to opening the natural gas industry to competition and private investment and establishing sound regulatory and pricing policies.

1 The São Paulo distribution network was originally constructed to distribute manufactured gas.

2 To counter Petrobras's bargaining power, the distribution companies used collective negotiations to achieve acceptable price and take–or–pay conditions, an approach that proved highly effective.

3 The bidding followed World Bank procedures for international competitive bidding.

4 The ANP is becoming functional with technical assistance financed by the World Bank.

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Competition in the Natural Gas Industry
The Emergence of Spot, Financial, and Pipeline Capacity Markets

Andrej Juris

Countries in Asia, Europe, and North and South America are introducing reforms to boost efficiency and attract new private investment in their natural gas industries. The trend has been to unbundle along vertical and horizontal lines and to open wholesale gas markets to new entrants. These new entrants stimulate competition and the development of new markets—in gas supply, in financial gas contracts, and in pipeline capacity. Such has been the success of these new markets—especially in the United States and the United Kingdom—that it has prompted a search for other potential markets in the industry. This Note describes the underlying structural and trading arrangements in the gas and pipeline markets. Two companion Notes examine these markets in the United Kingdom and the United States.

The Emergence of Gas and Pipeline Markets

Government's traditional control of gas companies and intervention in their operations and investment decisions often led to distorted prices, inefficient operation, and deteriorating infrastructure. Thus reforms have aimed at limiting government's role in the industry's day–to–day operations and establishing an effective regulatory framework under which market forces would balance demand and supply in segments of the industry where competition is feasible, and only those segments where competition is not feasible would remain subject to economic regulation.

A traditional, vertically integrated gas industry typically has only one market, where natural gas and transportation services are sold as a "bundle" to final consumers (figure 1). Introducing open access to pipeline transportation or unbundling supply from transportation creates two distinct markets: the gas market, where participants trade natural gas as a commodity and minimize price and supply risks, and the transportation market, where participants trade transportation services for shipping gas through the pipeline system (figures 2 and 3).
The increasing complexity of transactions in both markets calls for the use of intermediaries and for spot markets that promote efficient pricing and minimize transaction costs. Well-functioning spot markets concentrate trading in a central location where gas supplies and pipeline capacity are easily accessible. Spot market trading typically arises first in natural gas because of the viability of competition in the gas market. As deregulation of the gas industry continues, however, markets may also emerge in other segments, such as natural gas storage, metering and meter installation, pipeline construction, and system balancing.

But markets cannot be created in all segments of the gas industry, so reformers must consider the viability of competition and markets in each segment separately. The market for natural gas has great potential for competitive supply and demand because economies of scale are relatively unimportant in natural gas production and trading.

Multiple firms can operate in the market unless it is extremely small, and prices of natural gas can be freely determined by market forces. By contrast, the natural monopoly characteristics of pipeline transportation prevent efficient operation of multiple pipeline firms in the same market unless it is extremely large. As a result, tariffs for pipeline transportation must be subject to economic regulation to prevent an incumbent pipeline company from exercising its market power.

Both structural and regulatory changes have generally played an important part in reforms of the natural gas industry. In the United States, however, reform has focused on gradual regulatory changes, since the industry was already vertically unbundled. The government created a competitive wholesale gas market by deregulating wholesale gas prices and unbundling the supply of natural gas from transportation on interstate pipelines. And it promoted flexibility in pipeline transportation services by allowing resale of firm transportation contracts in a secondary market. Under way for more than ten years, the deregulation process has now shifted its attention to the retail gas market.

Gas reform in the United Kingdom did involve both structural and regulatory changes, but in an inappropriate sequence. Gas supply to large consumers was liberalized and opened to competition in 1986, but the government failed to vertically unbundle British Gas, the former monopolistic gas company. Independent supply companies could not compete effectively with British Gas, which controlled access to transportation and thus gas supply. Only after repeated regulatory interventions in the gas market in the early 1990s and an intricate separation of British Gas into two companies in 1996 could competition flourish in the wholesale gas market. Correcting the initial failure to decentralize the industry structure took ten years. But the new industry structure offers better conditions for liberalizing the retail gas market.

Argentina and several other countries in Latin America adopted a more radical approach to reform, vertically unbundling the industry and deregulating the wholesale gas market in one quick stroke. In these countries gas reform was part of a larger economic reform package to enhance efficiency and investment in all major infrastructure sectors.

The Natural Gas Market

In the natural gas market, where natural gas is traded as a commodity separate from transportation services, participants typically trade natural gas under contracts. These contracts are of two main types, physical and financial, traded in different markets. The main participants in both the physical and the financial gas markets may include producers, traders, suppliers, pipeline companies, and distribution utilities, depending on the
industry’s degree of vertical and horizontal unbundling.

**The Physical Gas Market**

Participants in the physical gas market trade contracts for the physical delivery of natural gas—physical gas contracts (sometimes referred to as cash gas contracts). These contracts differ in two main dimensions, the purpose of the transaction and the duration of supply, and thus divide the physical gas market into several segments. A purchase of gas for resale takes place in the wholesale gas market, and a purchase for end use in the retail gas market. Wholesale transactions are concluded between producers, traders, suppliers, pipeline companies, and distribution firms.

**MARKETS IN THE NATURAL GAS INDUSTRY**

![Figure 1](Image1.png)

Figure 1
Vertically Integrated Natural Gas Industry

![Figure 2](Image2.png)

Figure 2
Open Access and Wholesale Competition
while retail transactions occur between suppliers and industrial or residential consumers.

Differences in the duration of gas supply divide gas contracts into three classes:

Short−term gas contracts, for supply of up to one calendar month.

Medium−term gas contracts, for supply of one to twelve months.

Long−term gas contracts, for supply of more than one year.

Natural gas transactions were traditionally based on long−term supply contracts between integrated gas companies and their customers. Because these contracts fixed the price and volume of gas to be supplied over a specified period, they reduced supply and price risks. But they provided little flexibility to reflect the economic value of natural gas under changing market conditions. For example, the economic value of natural gas tends to be high during extremely cold weather, when gas supply and transportation capacity are generally constrained. If the contract price of natural gas is fixed, supply and demand do not adjust in response to the higher value. Demand may exceed supply, and gas shortages may occur. In such a situation demand must be rationed by administrative rules—an interruption of supply—rather than prices.

Deregulation of the gas industry and greater flexibility in natural gas supply change the importance of long−term supply contracts. Participants in deregulated gas markets need to balance their supply and demand in both the long and the short term so they can react to changing market conditions. Short−term balancing can be achieved by trading in the short−term (spot) market, where producers, traders, suppliers, distribution utilities, and large end users enter into daily trades. Spot market participants can acquire natural gas supplies relatively quickly and choose the time and quantity of supply based on needs and price. That flexibility allows them to form a portfolio of long and short−term contracts that minimizes supply and price risks in both the long and the short run.

Spot markets typically develop where buyers and sellers are concentrated, such as at a pipeline interconnection near a large metropolitan area or at a major terminal in a gas−producing region. The Henry Hub in Louisiana and the Bacton terminal in the United Kingdom, for example, are both located at the entry point to a major pipeline network in a large producing region. By aggregating supply and demand, spot markets offer industry participants the benefits of intensive competition among buyers and sellers, high liquidity, and greater efficiency in the pricing
of natural gas.

In a well-functioning spot market short-term (spot) prices reflect the economic value of natural gas. Gas industry participants use spot prices to value supply contract portfolios and make decisions about the size and timing of consumption. Thus spot markets in natural gas serve the same function as other commodity or stock exchanges—they reveal the market value of the commodity traded. In the United States spot prices of natural gas at Henry Hub are a common indicator of market value.

Spot prices tend to be volatile, however, responding to changes in underlying factors of supply and demand such as the weather, available pipeline capacity, or consumption patterns. Participants in spot markets, unable to predict the future prices of natural gas, are exposed to price risk. Their demand for tools to minimize this price risk leads to the development of a financial gas market.

The Financial Gas Market

The contracts traded in the financial gas market serve two main purposes: they minimize the price risk in the natural gas spot market, and they minimize the basis risk resulting from the changing price differential between physical and financial gas contracts. Financial gas contracts also serve as an instrument for speculation and price arbitrage in the gas market. They are seldom used for physical delivery of natural gas.

The most common financial gas contracts are forward contracts, swaps, futures, and options.

Forward contracts and swaps are typically custom-tailored, with every aspect negotiated by the parties to the contract. Futures and options are standardized contracts typically traded in established commodity exchanges such as the New York Mercantile Exchange (Nymex) in the United States.

Transactions in the financial gas market involve the transfer of risks between market participants with different risk characteristics and risk management skills. For example, a distribution company with an obligation to serve final customers tends to be exposed to price risk because it cannot adjust its demand in response to changes in spot prices. Intermediaries such as traders or brokers tend to be experts in managing risk and can therefore better absorb the price risk. A transfer of price risk from the distribution utility to intermediaries minimizes the overall exposure to price risk and the costs of risk management.

A financial gas market will emerge in countries where the physical gas market has reached a certain level of maturity and a large share of natural gas is traded under short-term contracts. Since only a few countries have a mature spot market, the financial gas market is a relatively new concept. Only the United States and the United Kingdom have active financial gas markets today. Nymex, in the United States, developed and actively trades three natural gas futures and options contracts for delivery in three major spot markets in the United States and Canada. The International Petroleum Exchange, in London, trades a natural gas futures contract for delivery at the National Balancing Point, a notional balancing point in the pipeline system of BG (the pipeline transportation spin-off of British Gas). Financial gas markets are likely to emerge in other countries as deregulation continues.

The Transportation Market

Contracts traded in the transportation market cover transportation services, the supply of pipeline capacity and movement of natural gas needed to deliver gas to a desired location. Pipeline companies sell transportation contracts to shippers—any industry participants that want to move natural gas—in the primary transportation market. In some instances holders of firm transportation contracts may resell them to other market participants in the secondary transportation market.
The Primary Transportation Market

The contracts purchased by shippers in the primary transportation market give them the right to transport natural gas under specified conditions. The most important distinctions among transportation contracts are the duration and the reliability of the services provided. Contracts can be long, medium, or short term. And they can provide firm or interruptible service, a distinction that determines the priority given to a shipper during capacity shortages. Transportation contracts also specify the location, timing, and volume of natural gas shipments.

The natural monopoly characteristics of pipeline transportation require that the primary transportation market be regulated to limit the market power of pipeline companies and promote efficient allocation of resources. A pipeline company must incur substantial fixed costs to construct the pipeline system before it can provide transportation services. And these fixed costs dominate the company's cost structure because the variable costs of shipping natural gas through the system tend to be relatively low. Pipeline transportation exhibits economies of scope as well as scale. Once the pipeline is constructed, a company typically uses the same facilities to offer different transportation services.

Deregulation of natural gas markets creates a need for flexible transportation services. Market participants need to be able to match their gas supplies with transportation services. And they often require short-term balancing of natural gas supply and demand to optimize the cost and reliability of natural gas deliveries. They can achieve such balancing only if they can match their port–

If transportation contracts establish transferable property rights to pipeline capacity, contract holders can trade the contracts freely and the secondary market can flourish.

The Secondary Transportation Market

Holders of unused firm transportation contracts can resell these contracts in the secondary transportation market. Buyers and sellers in this market may be almost any participant in the primary transportation market, though pipeline companies are excluded because of their market power. Secondary transportation markets came into existence in the United States in 1992, when the Federal Energy Regulatory Commission introduced a capacity release program requiring interstate pipelines to allow holders of firm transportation contracts to release, or sell, any unused portions of their reserved pipeline capacity to other network users. The United Kingdom introduced a similar program of pipeline capacity resale in 1996 under the Network Code of British Gas.

The resale of transportation contracts promotes efficient allocation of transportation capacity. As a result of short-term changes in supply and demand, some pipeline users will not utilize all their contracted capacity, while others will lack capacity to ship their gas. In the absence of a secondary market holders of unused capacity cannot sell it to those who need it and pipeline capacity may go unused. A pipeline company can use spare capacity for interruptible services, but efficiency may be compromised because interruptible tariffs tend to undervalue
available capacity. By contrast, the resale of firm transportation contracts allows contract holders to realize market value for unused pipeline capacity. Thus it can lead to optimal allocation of transportation capacity among market participants, based on their willingness to sell or pay. The efficiency of capacity allocation is sometimes constrained, however, by regulation of the resale price, which tends to be capped to reduce the potential for exercise of market power.

To promote efficiency in the secondary transportation market, it is important to assign property rights to transportation capacity to a large number of shippers. If transportation contracts establish transferable property rights to pipeline capacity, contract holders can trade the contracts freely and the secondary market can flourish. But if transportation contracts establish property rights that are not transferable, the resale of contracts is impossible unless it is intermediated by the pipeline company. Contract holders may still engage in side-dealing by using their spare capacity for delivery of third-party gas, but these deals often involve high transaction costs. Firm capacity contracts that give their holders the right to reserved pipeline capacity typically establish property rights. But the transferability of such contracts depends on prevailing regulation.

The resale of transportation contracts can take several forms. Auctions in which shippers bid by price can be used for trading both long- and short-term transportation contracts, although they may be too time-consuming for resale of short-term contracts. Transactions in which shippers mutually agree on the conditions for contract resale give the parties a great deal of flexibility and so are well suited for all types of transportation contracts. But this form of trading may be too costly for smaller and less informed participants that have to shop around for the best deal.

Short-term transportation contracts may be traded in a transportation spot market. To promote liquidity and efficient pricing in this market, transportation contracts need to be standardized in all important dimensions. The resale of short-term transportation contracts not only promotes efficient allocation of contracts. It also facilitates the simultaneous clearing of gas and transportation markets by enabling market participants to match their spot gas transactions with short-term transportation contracts. Spot markets in transportation contracts are developing in the United States, where electronic systems for trading natural gas and transportation contracts link large numbers of buyers and sellers.

**Market Prospects**

Having achieved considerable success in wholesale market competition, the United Kingdom and the United States are moving toward competition in retail gas supply to small consumers, under arrangements that will allow consumers to choose among gas suppliers and reap efficiency gains like those in the competitive wholesale gas market. The services needed to support retail competition, such as metering and billing, are also targets for the introduction of competitive provision. The unbundling of pipeline transportation has led to marketlike operation of natural gas storage facilities, with storage operators taking advantage of seasonal and daily price variations in nearby spot markets. Active trading of short-term transportation contracts will eventually give rise to a financial transportation market where participants can minimize the price risks in the physical transportation market. And with continued advances in technology and in the understanding of how the natural gas industry operates, more opportunities for competitive provision of goods and services will surely emerge.

Natural Gas Markets in the U.K. Competition, Industry Structure, and Market Power of the Incumbent

Andrej Juris

The deregulation of the U.K. natural gas industry has facilitated new entry and competition in almost all segments of the industry except pipeline transportation. The new regulatory framework, developed largely by the Office of Gas Regulation (Ofgas), has allowed market forces to stimulate the development of a variety of specialized services and market transactions to meet customer needs. But the entire process has been difficult because of a flaw in the initial industry structure: the government privatized British Gas as a vertically integrated company. The U.K. experience shows that leaving gas supply integrated with pipeline transportation and tying up gas in long term contracts impede competition. This Note reviews the U.K. reform and the development of new spot, on–system, and "Flexibility Mechanism" markets.

Initial Reforms

Before 1986 British Gas operated as the publicly owned, vertically integrated transporter and supplier of natural gas in the United Kingdom. Only gas production was open to competition, and this segment was dominated by multinational oil companies. In 1986 the government privatized British Gas, choosing to leave it a single, vertically integrated company in order to speed the transaction and maximize the sale proceeds. At the same time it separated the gas market into three major segments:

The wholesale market, where gas is traded between producers, traders, British Gas, and independent suppliers.

The contract market, where gas is supplied to large consumers (initially those consuming more than 25,000 therms a year, now those consuming more than 2,500 therms a year) by British Gas or independent suppliers.

The tariff market, where gas is supplied to small consumers (those with annual consumption below the threshold for large consumers) by British Gas.

The government opened the wholesale and contract gas markets to promote efficiency and lessen the traditional dominance of British Gas. It permitted large consumers to contract for natural gas directly with procedures. And it allowed independent gas shippers, traders, and suppliers to arrange gas supplies for large consumers in order to create competition in wholesale supply.1 The tariff market remained closed to competition, and British Gas continued to be the sole supplier of natural gas to small consumers. The government believed, rightly at the time, that competition in gas supply to small consumers was not economically feasible. Wholesale and contract gas prices were liberalized, while Ofgas regulated retail tariffs to protect consumers from the market power of British Gas.

Structural Lessons

The initial decision not to unbundle British Gas in 1986 hindered development of a competitive gas market. Because British Gas controlled the entire pipeline system and held long–term gas supply contracts with producers, it was able to retain a de facto monopoly in the wholesale and contract gas markets and control entry by independent gas suppliers. In an attempt to improve access to gas supplies and transportation, Ofgas introduced the 90:10 rule in 1989, which prohibited British Gas from contracting more than 90 percent of gas deliveries from any field on the U.K. continental shelf. The 90:10 rule effectively forced producers to market their gas to independent suppliers,
promoting the development of wholesale gas trading at the "beach," the entry terminals of the British Gas pipeline systems.

The 90:10 rule did not, however, remove the main source of the problem: the ability of British Gas to control access to its pipeline network. Complaints about the company's market power prompted another set of regulatory measures in the early 1960s, when Ofgas asked British Gas to release more natural gas to independent suppliers and to build "Chinese walls" separating its gas supply and pipeline transportation businesses. The intention was to increase independent suppliers' access to natural gas from producers and to level the playing field for suppliers contracting for pipeline transportation.

British Gas complied by selling about 5 billion cubic meters of natural gas (roughly 3 percent of the total gas supply) to independent suppliers and by creating two divisions, British Gas Energy and British Gas Trans Co. But the prospect of further regulatory intervention once the retail gas market was liberalized led the company to seek more permanent structural change. In 1996 it decided to split its assets into two companies: Centric, a gas production, sales, and supply business, and BG ple, a transportation and storage business. This separation, or "demerger," of British Gas was completed in 1997.

The demerger finally corrected the government's failure to restructure the industry at the time of the privatization. The costs of the failure had been significant. The industry's flawed structure resulted in frequent regulatory interventions in the markets and disputes between Ofgas and British Gas. This increased the regulatory risk and cost of capital for British Gas, which saw a big drop in the market value of its assets. Between the fall of 1993 and mid–1996, when the disputes were particularly intense, the market value of the assets fell by half—from £15.5 billion to £7.7 billion. And the demerger itself was a costly exercise, with the company paying millions of pounds in accounting and legal fees.

The U.K. experience shows that if a single company controls access to gas supplies and transportation capacity, as British Gas did, competition may be inhibited. Simply removing administrative barriers to entry in gas supply and deregulating gas prices are not enough to ensure competitive gas markets. A move from monopolized to truly competitive gas markets requires structural and regulatory changes that protect new entrants from the market power of the incumbent. It took almost a decade to remedy the failure to unbundle British Gas before its privatization. Only after U.K. regulatory authorities intervened in the acquisition of natural gas from producers and the incumbent's operation of the pipeline network could real competition emerge in natural gas supply.

**New Markets**

Competition has fostered new ways of trading natural gas, reflecting market participants' need for more flexible gas supply arrangements. Spot markets have formed at major terminals, allowing market participants to balance their short–term supply and demand by trading natural gas. As a result of new pipeline operating rules, a flourishing spot market has developed within the pipeline system. The pipeline operator also uses market pricing to determine the costs of balancing supply and demand over the pipeline network.

While the natural gas markets are substantially deregulated, gas transportation remains heavily regulated because of the natural monopoly characteristics of pipeline transportation. British Gas–followed by its transportation spin–off, BG–has remained the single operator of the U.K. pipeline system, and transportation charges are regulated. The secondary transportation market is just beginning to emerge, with resale of pipeline capacity among
shippers allowed only since 1996.

As markjets for wholesale (and, increasingly, retail) gas supply have become more and more competitive, the quantity and quality of services available to market participants have improved, and consumers have benefited from declining real prices for natural gas even as consumption has been increasing. Residential prices fell by 24 percent in real terms between 1986 and 1995, and industrial prices by 47 percent. During the same period consumption increased by 38 percent. The deregulation of wholesale and contract markets has attracted more than forty suppliers, all competing fiercely. The increased competition in the contract market is reflected in the diminishing market share of British Gas, which fell from 80 percent in 1992 to 33 percent by the end of 1996. The industry operates much more efficiently than it did before 1986, and consumers have reaped the benefits.

**Market Dynamics**

The trading and contracting of natural gas in the United Kingdom have changed dramatically since the privatization of British Gas in 1986. Traditionally, most natural gas was sold under long- and medium-term contracts between producers and British Gas at the wholesale level and between British Gas and consumers at the retail level. After the contract market was liberalized in 1986, long-term contracting became insufficient to meet the needs of the growing number of participants in the wholesale and contract gas markets. Independent suppliers and large consumers demanded contractual and supply flexibility to allow them to efficiently balance their short-term supply and demand. Independent suppliers also sought a trading location that would give them unrestricted access to gas deliveries, outside the control of British Gas.

Aided by regulatory measures, the market response to the demand for greater flexibility and better location was the development of spot markets. First, wholesale gas trading moved to the “beach” where natural gas supply from more than forty producers promised sufficient availability of natural gas and flexibility in delivery conditions. Second, the concentration of trading at entry terminals promoted the development of spot markets, where natural gas is continuously traded. More trading opportunities were created when British Gas separated its gas supply and pipeline transportation operations. The introduction of the British Gas Network Code in 1996, which set out the rights and responsibilities of users of B’s pipeline network, created two additional gas markets within the pipeline system of British Gas.

Participants in the U.K. gas market now use four mechanisms for trading natural gas (figure 1):

- Bilateral contracts.
- Spot markets.
- The on-system market.
- The Flexibility Mechanism.

**Bilateral Contracts**

Bilateral contracts represent the traditional form of natural gas trading in the United Kingdom. Producers and British Gas typically concluded
Mechanisms for Natural Gas Trading in the United Kingdom

long-term take-or-pay, or "depletion," contracts under which British Gas covered a share of the financing of a producer's field development cost in exchange for assured future gas deliveries.

The opening of natural gas supply to competition has introduced new contractual relations in the gas market as producers and independent suppliers have looked for ways to achieve greater supply and price flexibility. This has initiated the development of a wide range of long-, medium-, and short-term supply contracts with delivery provisions to meet specific demand and supply characteristics of contracting parties.

But the opening of the gas market to competition also exposed British Gas to transition costs, net liabilities resulting from over contracting. In 1996 it held take-or-pay obligations to purchase about 4.6 billion cubic feet of gas a day (bcfd) from producers over the next five years, while gas sales were projected at 4.35 bcfd, on the assumption that BG would maintain a 90 percent share in the tariff market in 1998. That resulted in an estimated surplus of 0.25 bcfd, or 5 percent of take-or-pay obligations, with a value of £528 millions. Although this surplus is not a significant volume, it still represented almost 30 percent of spot market sales in 1996. Thus if BG delivered its surplus gas to spot markets, it would drive down spot market prices and potentially harm its position in the retail gas market. In the event, the losses have probably been mitigated by delays in the introduction of retail competition.

Spot Markets

Spot market trading has developed with the opening of natural gas supply to competition. As the large number of contractual relations between producers and suppliers made it infeasible to always negotiate all aspects of supply contracts, demand arose for the
standardized contracts suited for spot market trading. Another factor in the development of spot market trading has been the gradual shift in natural gas transactions to locations where producers and suppliers can rely on standardized delivery conditions and have the best access to the pipeline system.

Natural gas spot markets have developed at six onshore terminals of the British Gas pipeline network, where the concentration of producers' gathering pipelines and the transportation pipelines of British Gas promised good availability of both gas supplies and transportation capacity. The spot markets enable participants to balance their supply and demand in the short term by buying or selling natural gas in one or more central delivery locations. The high volume of natural gas trading in the spot market has led to greater standardization in supply conditions, such as in the duration of delivery, and thus in gas supply contracts. This standardization of contracts promotes market liquidity and efficiency in spot gas prices.

Spot market gas trading in the United Kingdom is bilateral, involving producers and shippers, or on a brokerage basis, with traders often acting as intermediaries. Spot trading started in 1989–90 as a bilateral telephone market between producers and independent suppliers, but trade volumes were low because most producers' gas supply was contracted by British Gas. Over time there has been a large increase in volume and in the number of traders.

The most active spot markets are at the Bacton and St. Fergus terminals, which are well connected with large producer and consumer areas. The most common contracts traded in these markets are day-ahead and monthly gas contracts, specifying delivery on the next day and in the coming months. Other contracts traded in spot markets include:

- Balance gas contracts, for delivery in the rest of the current month.
- Quarterly and annual gas contracts, for delivery in a specific quarter and year.
- Time spread contracts, for the exchange of contracts with different delivery periods.

Despite the increasing volume of gas traded in spot markets, trading remains relatively thin and illiquid. Trading volumes at Bacton in 1996 ranged from 2 million to 8 million therms a day, only 5 to 10 percent of the total daily supply. Prices at the terminal varied accordingly—from 9 pence to 14 pence a therm. The U.K. gas market appears to be relatively small to support efficient functioning of five to six spot markets. Perhaps a more central location is needed where most of the country's natural gas supplies could be traded. British Gas, inspired by the growing use of natural gas spot trading, introduced a central location within its pipeline system when it launched its on-system market in 1996.

The On-system Market

The on-system market is basically a natural gas spot market with the delivery point at the National Balancing Point (NBP), a notional point in BG's pipeline network at which BG balances its high-pressure pipeline system. In effect, all gas supplies transported through BG's high pressure pipelines can be traded at the NBP.

A transaction in the on-system market typically involves shippers that own transportation contracts and are willing to sell or purchase natural gas. Selling shippers use their reserved pipeline capacity to deliver natural gas to the NBO, where they sell it to interested buyers. Buying shippers then use their pipeline capacity to transport the gas from the NBP to the desired location. Transactions are facilitated by BG, which keeps track of traded volumes and provides transportation services.

The on-system market has become increasingly popular among shippers because of its central location, accessibility, and low transaction costs. The whole range of natural gas contracts, much the same as those traded in a spot market, are
traded daily in the on–system market. Traded volumes in the on–system market, and possibly in other spot markets, are likely to increase as the share of Centric, the British Gas supply and trading spin–off, in the liberalized retail market diminishes and more gas becomes available from producers as a result.

The strong prospects of the on–system market and its potential for efficient pricing of physical gas contracts have led the International Petroleum Exchange (IP) in London to develop its first natural gas futures contract based on delivery at the National Balancing Point. The introduction of the

The Flexibility Mechanism allows market–based determination of the value of the natural gas needed to restore the balance in BG’s pipeline system.

IPE Natural Gas NBP contract on January 31, 1997, marked the beginning of financial gas trading in the United Kingdom and in Europe. The contract has found broad acceptance among gas traders because of its central delivery location and smooth administration. By July 31, 1997, the volume traded under such contracts had reached almost 30 million therms, equal to about 40 percent of the United Kingdom's daily production of natural gas.

The BG’s Network Code requires all shippers to balance their gas shipments through the pipeline system—that is, to maintain their injections and withdrawals of natural gas below a specified tolerance level—on both a daily and a monthly basis. Shippers can balance their shipments by buying or selling natural gas in the highly liquid on system market, where the price of natural gas determines the cost of maintaining their balance. But shippers do not always maintain their daily balance, and the whole pipeline system may become unbalanced if the sum of individual imbalances exceeds a certain tolerance level. The pipeline operator must then inject or withdraw natural gas to restore the balance in the pipeline system. The value of the natural gas in these transactions is not reflected in the on–system price, because BG cannot participate in on–system trading. To facilitate the pricing of this gas, British Gas introduced the Flexibility Mechanism in 1996.

The Flexibility Mechanism

The Flexibility Mechanism allows market–based determination of the value of the natural gas needed to restore the balance in BG's pipeline system. BG trades this natural gas in an auction. Interested shippers post their bids on an electronic network, specifying volumes and the prices at which they want to buy or sell. BG buys natural gas if it expects that injections into the system will be less than withdrawals, and sells natural gas if it expects the reverse. BG accepts the bids that cover the expected system imbalance and that either minimize the cost of buying natural gas or maximize the revenue from selling it. The price of the last accepted bid determines the system marginal price at which transactions between BG and shippers are concluded. BG solicits bids from shippers daily, so that they are always available.

As in any auction, competition among shippers promotes efficient pricing of natural gas traded under the Flexibility Mechanism. If shippers want to ensure that BG accepts their bids, they will reveal their true willingness to buy or sell natural gas. BG can construct a market (supply and demand) from shippers' bids, and decide which ones minimize the cost of restoring the system balance. Since the last accepted bid determines the price for all transactions, the system marginal price reflects the economic value of natural gas needed to restore the balance in BG's pipeline system.

The cost of restoring the system balance under the Flexibility Mechanism is recovered from the shippers that cause the imbalance. Undisciplined shippers must either pay the system marginal price for the natural gas below the tolerance level of their shipments or accept the system marginal price for natural gas that is above the tolerance level. Since the system marginal price is typically higher than the price of natural gas sold or
lower than the price of natural gas purchased in the spot market, undisciplined shippers experience losses on their imbalances in addition to any imbalance penalties imposed by BG. These potential losses deter shippers from violating the balancing rules of the Network Code.

Conclusion

The U.K. experience shows that the development of competitive natural gas markets must be supported by an appropriate industry structure and regulation to protect new entrants from the market power of the incumbent. To promote competition, the liberalization of entry to gas supply and of gas prices must be accompanied by open access to gas supplies from producers and to transportation capacity for delivering natural gas to consumers. The practices of tying up natural gas in long–term supply contracts and integrating gas supply with pipeline transportation must be eliminated to enable independent suppliers to acquire natural gas in the wholesale market, gain equal access to pipelines, and start to compete on equal footing with the incumbent gas company.

Developing competitive natural gas markets can require frequent regulatory changes and interventions, as it did in the United Kingdom. But these interventions can lead to many controversies and disputes among industry participants and between the industry and the regulator, often with harmful effects for both companies and consumers. The cost of increased regulatory risk of political intervention discourage investment in the gas sector. So it is important to introduce structural changes at the beginning of the reform to set the stage for developing markets and competition later in the reform.

Market forces have proved to be vital and effective in the gas industry, once appropriate structural and regulatory measures establish some breathing room. New entrants in gas trading, shipping, and supply can emerge overnight and introduce new methods of transacting business, such as spot market trading. By concentrating trading in one location, spot markets like the U.K. on–system market can serve a vital function for market participants that require flexibility in gas supply and efficient pricing or natural gas. And spot market pricing of natural gas can be used for valuation of system balancing, as it is in the Flexibility Mechanism of BG.


1 Categories of market participants are defined in the Network Code of BG plc, the pipeline transportation spin–off of British Gas. Shippers are firms with shippers licenses that buy gas from producers, sell it to suppliers, and contract with BG to transport the gas to consumers. Suppliers are firms with supplier licenses that buy gas from shippers and then sell it to consumers. They do not deal directly with producers or BG. Since many companies in the United Kingdom have both supplier and shipper licenses, these terms are used interchangeably here. Traders are firms that buy and sell natural gas in a spot market and do not deal directly with consumers or BG.

2 Based on data from the U.K. Department of Trade and Industry.


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Development of Competitive Natural Gas Markets in the United States

Andrej Juris

The United States enjoys a highly competitive natural gas market and an increasingly efficient market for pipeline transportation. Consumers have benefited from changes to both the structure and the regulation of the industry in the past ten to fifteen years. These changes have lowered natural gas prices and broadened the range of services offered by gas companies. This Note reviews the forces driving the regulatory changes and the effects of the changes on the functioning of gas markets. It also provides an overview of natural gas trading mechanisms in the United States. The focus is primarily on the wholesale natural gas market, the market most affected by deregulation.

Deregulation of the Gas Industry

The U.S. natural gas market is the world's largest, with a total supply in 1996 of 25.6 trillion cubic feet. About 75 percent of this supply is produced domestically, with the balance from storage withdrawals and imports (12 percent each). Gas production is concentrated in the South, along the Gulf Coast in Louisiana and Texas, and in smaller producing regions in Alaska, the Southwest, and the central United States. But most natural gas consumers are in the Northeast, the Midwest, and the Pacific Coast region, all areas where imports of Canadian gas play an important part in meeting demand. The geographic imbalance between producers and consumers means that large quantities of natural gas must be transported long distances across the country and the continent. So even small inefficiencies in production or transportation of natural gas can have a large economic effect on the gas industry.

The U.S. natural gas industry has gone through a full cycle of government regulation in the past sixty years. During the first several decades of the century the industry enjoyed limited oversight by the government. That changed in 1938, when the Natural Gas Act established a basis for regulating the prices and activities of gas companies. Over the next forty years regulation gradually increased its reach as new regulatory institutions and policies emerged. Interstate transactions came under regulation by the Federal Power Commission (FPC), later succeeded by the Federal Energy Regulatory Commission (FERC), while intrastate transactions were regulated by state agencies.

Overregulation

By the 1970s regulatory agencies controlled almost all aspects of business in the industry. Regulation was applied not only to industry segments characterized by natural monopoly, such as pipeline transportation, but also to competitive segments, such as production and wholesale supply. The excessive control burdened companies and distorted natural gas prices and consumption patterns.

Excessive regulation of gas producers, for example, led to gas shortages in the 1970s. In the 1950s the FPC had started to regulate prices at the wellhead where interstate pipeline companies purchased natural gas from producers. But with hundreds of active wellheads in the country, the commission was unable to process all the tariff applications. By 1960 it had completed 10 out of 2,900 applications. It was forced to adopt an "area rates" approach, setting a uniform tariff for all producers in the same geographic area. Although this step decreased the number of tariff cases, the approval process was still very slow, averaging ten years per case.

The area rates were based on average historical costs of production. These averages became very low relative to the increasing costs of production in the 1960s and early 1970s. Producers found sales of natural gas to interstate
pipelines unprofitable and curtailed gas supply to the interstate

Even small inefficiencies in production or transportation of natural gas can have a large economic impact on the gas industry.

market. They found it more profitable to supply gas to the intrastate market in Texas or Louisiana, for example, where wellhead prices were unregulated or considerably higher than in the interstate market. As a result interstate pipelines faced shortages of gas supply and consumers in the Northeast and Midwest experienced supply interruptions.

To attract producers back to the interstate market, the FPC adopted new regulation in the mid1970s. A uniform national wellhead tariff was set at an average of current and expected costs of gas production, leading to a quintupling in wellhead prices. However, the new regulation did not eliminate the main cause of gas shortages—the regulation itself. National tariffs based on average costs seldom reflected the true economic value of natural gas—the price that would exist in a competitive market. And even if national tariffs did reflect economic value, they applied only to supply contracts concluded after 1975. Supply contracts concluded earlier were priced at low historical tariffs. Since interstate pipelines had a large portfolio of old gas contracts, the average wellhead costs of natural gas were well below the economic value. Consumer demand was therefore much higher than it would have been in a competitive market. This aggravated supply shortages. The costs of gas shortages in the 1970s were estimated at US$2.5 billion to US$5.0 billion a year.

Deregulation

Gas shortages prompted deregulation aimed at promoting efficiency in production and bulk supply of natural gas. The main strategy was to allow free competition among producers and suppliers in the wholesale gas market. The process was launched in 1978 when Congress adopted the Natural Gas Policy Act, authorizing the FPC to liberalize interstate natural gas markets. The FPC adopted a number of regulatory measures that partially liberalized wellhead prices of gas, allowed competition in the wholesale gas market, and enhanced regulation of interstate gas pipelines. Congress adopted additional legislation in 1989 and 1992 further liberalizing wellhead gas prices and interstate natural gas transactions.

Among the most important measures adopted by FERC was Order No. 436 of 1985, which introduced open access to interstate pipeline transportation and limited the use of long–term contracts. Local distribution utilities and large end users were allowed to purchase natural gas directly from producers, bypassing interstate pipeline companies. Companies that agreed to provide open access to their interstate pipelines were allowed to charge an open access tariff, regulated by FERC, for provision of transportation services. To promote competition in the bulk supply of natural gas, FERC allowed gas marketing companies to arrange purchases and sales of natural gas on behalf of other industry participants.

Figure 1
Traditional Structure of The U.S. Gas Industry, Before 1985
Deregulation of the gas industry followed when FERC adopted Order No. 636 of 1992, which required the interstate pipeline companies to unbundle natural gas sales from pipeline transportation by setting up separate affiliates to handle these activities. This removed an incentive for interstate pipeline companies to distort bulk supply competition by restricting access to pipelines.

To minimize distortions in the gas market caused by regulated prices for interstate pipeline transportation, Order No. 636 also enhanced the method for calculating transportation tariffs and introduced a program for the resale of firm transportation contracts. This program, the capacity release program, allows shippers (any users of pipeline transportation) to purchase pipeline capacity from shippers that have temporary or permanent excess reserved capacity. The capacity release market promotes the efficient allocation of transportation contracts among shippers and allows gas market participants to match transportation contracts to their gas supply contracts.

The two orders dramatically changed the operation of the gas industry, from tight regulation to free competition in the wholesale gas market. But implementation of the orders imposed large transition costs on some industry participants, which naturally opposed changes. Opposition to Order No. 436 was particularly strong. The transition costs related to Order No. 436 were estimated at US$11.7 billion in 1986, half the total book value of
interstate pipelines in 1984, at US$23.4 billion. The actual value of transition costs was $10.2 billion as of 1995.2

Only after FERC worked out a mechanism to distribute the costs among all industry participants could the orders be successfully implemented and competition flourish.

The costs arose in the following way. Before 1985 interstate pipelines entered into long-term supply contracts to purchase from producers and sell to distribution companies. Many of these contracts were concluded at very high wellhead prices—prices that pipelines, fearing a recurrence of the supply interruptions of the 1970s, were willing to pay. The uneconomic costs of gas purchases at the wellhead were borne by distribution companies and final consumers, since regulators allowed a pass-through of gas purchase costs to consumers. Order No. 436 allowed distribution companies to exit these long-term supply contracts with pipeline companies and purchase natural gas directly from producers. But pipeline companies were not allowed to exit their contracts with producers and so were left with large contractual obligations that they were unable to meet. The pipeline companies challenged the order in court, and FERC had to issue a new order (Order No. 500 of 1987) allowing the companies to pass on up to 75 percent of the transition costs to producers, distribution companies, and large consumers. Only then did the interstate pipeline companies begin to implement the open access regime on a large scale.

Order No. 636 completed the deregulation of the wholesale gas market by liberalizing entry into gas marketing. It was followed by a series of FERC orders to promote competition in the wholesale gas market and increase flexibility in interstate pipeline transportation. FERC is now focusing on developing short-term capacity resale and standardizing gas supply and transportation contracts.

**Impact**

Deregulation has changed the structure of the U.S. gas industry. Until 1985 the industry was vertically separated into production, pipeline transportation, and distribution (figure 1). However, all transactions were tightly regulated and completed under long-term contracts. The introduction of open access to interstate pipeline transportation in 1985 gave rise to the competitive wholesale gas market, and gas marketing emerged as a new segment of the industry (figure 2). The unbundling of interstate pipeline transportation completed the wholesale market’s transformation into a fully competitive market in 1992 (figure 3).

The liberalization of gas marketing and wholesale gas prices attracted many new companies

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**Figure 4**

Average Nominal Natural Gas Prices In The United States, 1984–95
into the wholesale gas market. The fierce competition that ensued among marketing firms and gas producers increased the pressure on wholesale gas prices. The price competition benefited not only wholesale market participants, but also final consumers of natural gas. Nominal prices of natural gas decreased or remained stable for all consumer categories after 1985 (figure 4). This meant a substantial decrease in real prices. Wellhead prices dropped on average 26 percent in real terms between 1988 and 1995, while prices at city gates (the entry points to pipeline networks for local distribution) fell by 24 percent.

Although there was an overall decline in retail gas prices, the distribution of benefits was uneven. Large consumers such as electric utilities and industrial consumers, which now purchase about 75 percent of their gas requirements in the competitive wholesale market, saw a 26 to 31 percent decline in real prices between 1988 and 1995. Most small consumers, however, are still captive to local distribution companies, and only about 25 percent of gas consumed by commercial users is purchased directly in the wholesale gas market. As a result commercial and residential consumers saw only a 12 percent decline in the average real price of natural gas between 1988 and 1995.

The Functioning of a Competitive Gas Market

After fifteen years of deregulation the wholesale gas market in the United States is fully liberalized and very competitive. Producers, pipeline companies, marketers, distribution companies, and large consumers trade natural gas in a large number of regional markets. Natural gas transactions are mostly arranged by gas marketers, which buy and sell natural gas on behalf of producers, distribution companies, and large consumers. Most trading takes place in spot markets at major market centers and hubs on interstate pipelines (figure 5). Important trading activity also occurs in financial gas markets (futures and options), where participants minimize the price risks in natural gas spot markets. And recently electronic trading systems have developed that allow the trading of natural gas and pipeline capacity in all major markets in the United States and Canada.

Gas marketers

Gas marketing companies are a dynamic and competitive segment of the U.S. natural gas industry. The share of deliveries they arrange increased from 20 percent of the total in 1987 to 49 percent in 1995. The first marketing companies emerged
in the late 1980s, but the main boom occurred after implementation of Order No. 636 in 1992, as producers, pipeline companies, and distribution companies formed marketing subsidiaries to take over natural gas acquisition and sales.

Marketing companies benefit other participants in the gas market by minimizing transaction costs and supply and price risks. They group the supply and demand needs of market participants and match them with appropriate contracts on a large scale. This intermediation reduces the costs of transactions by freeing buyers and sellers from having to shop for the best contract. At the same time, by aggregating contracts, marketers can diversify the supply and price risks of individual contracts. These risks often arise when market participants with different supply and demand characteristics try to arrange transactions on a bilateral basis. Because marketers can pool contracts in one portfolio, they are better able to absorb fluctuations in supply or demand.

As natural gas markets have become increasingly complex, marketing companies have sought to expand their size and scope in order to accommodate the diverse needs of their clients. In 1995 and 1996 a wave of mergers increased the concentration of sales. In 1994 the top ten marketers arranged average daily sales of about 31 billion cubic feet of natural gas, 42 percent of total U.S. daily consumption. In 1996, after mergers between several large players, the top four marketers alone accounted for this volume of sales. Despite this concentration, small marketers continue to play an important role, particularly in local markets, which arc commercially unattractive for major players.

Hubs and Spot Markets

Over the past ten years natural gas transactions in the wholesale market have gradually moved from wellheads to hubs at major interconnections of interstate and intrastate pipelines. Today most gas trading in the United States takes place in large hubs and market centers. Hubs are typically operated by one or several interstate pipeline companies, which own the pipelines interconnected at the hub. Hubs allow market participants to acquire natural gas from several independent sources and ship it to several different markets. This eliminates the need to contract natural gas and pipeline capacity all the way from the wellhead to the consumption site. Instead, shippers can combine supply routes across several hubs to diversify supply risks and minimize costs. Hub operators offer a wide variety of service–ranging from physical transportation of natural gas to storage, processing, and trading–providing great flexibility for shippers and marketers in trading and delivering natural gas.

Hubs have become very popular among marketers and other players in the wholesale gas market. More than fifty have been created across the United States since the first one, the Henry Hub, was established in May 1988 in Erath, Louisiana. The Henry Hub, which is also the largest hub in the United States, is a major natural gas interchange operated by Sabine Pipe Line Company, a subsidiary of Texaco. At this hub marketers and traders have access to large consumer markets in the Midwest, Northeast, and Southeast and along the Gulf Coast through nine interstate and three intrastate interconnecting pipelines. The market participants transported about 550 million cubic feet of gas a day through the Henry Hub in 1995.

Almost all major hubs in the United States have developed into spot markets where natural gas is traded continuously. The most important natural gas spot market is at the Henry Hub. This highly liquid and efficient spot market determines the market price of natural gas on a continuous basis. The Henry Hub spot price plays a key role in the U.S. gas industry. Gas industry participants use the spot prices to evaluate their contract portfolios and make consumption or investment decisions. And the Henry Hub is the pricing point for the first financial gas contract, the New York Mercantile Exchange (NYMEX) natural gas futures contract.
Financial Gas Market

Participants in natural gas spot markets in the United States face substantial price risks, as spot gas prices occasionally become highly volatile. A cold spell in February 1996, for example, caused extreme changes in spot prices at the Henry Hub. The average spot price in February 1996 was US$4.41 per million British thermal units (Btu), a record high compared with the average annual price of about US$2 per million Btu. The spot price at Henry Hub peaked at more than US$15 on February 2, 1996, and some industrial customers in Chicago paid a city gate price of US$45 per Btu.3

Most players in the gas market dislike high volatility in gas prices and seek ways to diminish the price risk in the financial gas market. They are aided by a large number of intermediaries—gas marketers that compete fiercely to structure the best ways of minimizing price risk for customers.

The U.S. financial gas market had its beginnings in the late 1980s, when several financial institutions began to offer custom–tailored natural gas futures contracts. As noted, the first standardized financial gas contract was introduced by NYMEX in April 1990, in the form of a natural gas futures contract with delivery at the Henry Hub. In April 1992 NYMEX added a natural gas options contract for delivery at the same location. NYMEX and the Kansas City Board of Trade have since introduced three more natural gas futures and options contracts, with three different delivery locations, to reflect regional differences in the market value of natural gas.

Financial gas trading has proved popular among gas market participants. Between 1991 and 1995 the volume of natural gas futures contracts traded increased from 0.42 trillion cubic feet to 80 trillion—four times the physical consumption of natural gas in 1995. The turnover in futures trading was US$125 billion in 1994, about 60 percent more than the turnover in physical gas that year. Most financial gas trading is conducted by marketers (which held 34 percent of the open interest on natural gas futures in the first quarter of 1996), producers (25 percent), and financial institutions (20 percent).

Electronic Trading and Market Centers

The introduction of electronic trading systems in the past few years has led to the development of market centers connected to multiple hubs by electronic networks. Electronic trading allows market participants to trade not only natural gas, but also pipeline capacity and storage services at all interconnected hubs and pipelines. It also facilitates communication between pipeline companies, shippers, and hub operators. Many electronic trading systems are linked to other commercial networks that supply information and news relevant to the gas industry.

Electronic trading has its origins in the electronic bulletin boards established by interstate pipeline companies in 1993 to support resale of pipeline capacity. Standardization of these electronic bulletin boards simplified the trading of pipeline capacity and showed the advantages of electronic trading. In late 1994 three commercial electronic trading systems were introduced that allowed market participants to trade natural gas and pipeline capacity electronically across several markets and pipelines. By the end of 1996 almost all major pipeline companies in the United States had introduced electronic systems.

The largest electronic trading system in the United States today is Altra Streamline, which is linked to eight market centers and forty–five interstate pipelines in the United States and Canada. The average daily volumes traded in this system range from 10 million to 200 million cubic feet of natural gas. Many small systems are integrating with larger ones to offer shippers and marketers a wide variety of services across all major gas markets in the United States. Electronic trading systems have great potential in the world of deregulated natural gas and power industries: they can link marketers to all major regional gas and electricity markets in the United States.
3: Conclusion

The U.S. experience in gas industry deregulation shows that the development of competitive gas markets must be supported by continuing improvement of the regulatory framework for the gas industry. Such measures as liberalizing wholesale gas prices and the bulk supply of natural gas free market forces in segments where competition is both feasible and socially desirable. Regulators also must focus on improving the regulation of pipeline transportation and minimizing its distortive effect on competitive gas markets. Introducing flexibility into pricing and other conditions of transportation contracts—such as delivery locations or the balancing of gas shipments—and standardizing pipeline operations promote more efficient use of pipelines and benefit all industry participants.

The U.S. experience also shows the viability of competition in the deregulated wholesale gas market and the important role of gas marketers and spot markets in increasing the efficiency of gas transactions and prices. Liberalized wholesale prices create many profit opportunities in the gas market, and these attract new entrants to production, marketing, and supply. Many of the new entrants bring new services and products that increase the range and quality of choices for gas industry participants.

Deregulation of the U.S. gas industry is far from complete, however. Regulation of charges for interstate pipeline transportation and capacity release still limits the efficient allocation of transportation contracts. But the most important task, and the biggest challenge for regulators, remains the deregulation of retail gas markets in individual states. These issues will continue to keep U.S. gas regulators busy.


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Gas Reform in Ukraine Monopolies, Markets, and Corruption

Laszlo Lovei

Reform of the natural gas industry in Ukraine has lacked a blueprint, and its direction has remained ambiguous. That ambiguity is the result of a conflict between those who advocate vertically integrated, opaque, monopolistic structures and those who want a transparent, competitive gas market governed by stable rules. This conflict will likely continue for several years, making the ultimate outcome difficult to predict. More by accident than by design, the reform produced a number of innovative features that might be of interest for other countries planning to restructure and privatize their gas industries.
In 1990 Ukraine consumed 115 billion cubic meters of natural gas (figure 1), representing about 40 percent of primary energy consumption. Over the next seven years gas consumption dropped to about 80 billion cubic meters a year. In 1997 industrial enterprises used 40 percent less gas than in 1990, households, budgetary entities, and district heating companies used 43 percent less, and power plants used 62 percent less. Despite the decrease, gas accounted for more than half of primary energy consumption in 1997, making Ukraine one of the world's most gas-intensive economies.

Ukraine has significant proven and probable gas deposits, both onshore and offshore. Today domestic gas fields produce about 18 billion cubic meters of gas a year (figure 2). The rest of domestic gas demand is covered by imports from Russia and Turkmenistan (though Russia was expected to become the sole external supplier in 1998). Ukraine is on the main export route for Russian gas to the rest of Europe. As payment in kind for the transit service, Ukraine receives up to 30 billion cubic meters a year of gas from RAO Gazprom. (RAO Gazprom, Russia's largest company, produces about a quarter of the world's natural gas.) Ukraine has extensive gas storage facilities (capable of storing an active volume of 32 billion cubic meters), a well-developed transmission system (10,000...
kilometers of highpressure lines), and an extensive distribution system (60,000 kilometers of small–diameter pipes). In early 1998 the gas industry employed about 110,000 people.

A 1994 parliamentary decision banned the privatization of transmission and distribution pipelines and the related infrastructure, so these formally belong to the State Property Fund and are not included among the assets of the gas companies. Until recently Ukrgazprom, a fully state–owned company, was the main domestic gas producer and operated gas transmission and storage facilities. About fifty oblast– and citybased distribution companies were responsible for the operation and maintenance of the distribution networks. Ukrgaz, a former association of gas distribution companies, managed stateowned shares in the gas distribution companies. Gas production, transmission, and distribution activities were supervised by the State Oil and Gas Committee, the main government agency responsible for implementing the government's gas strategy and the de facto representative of the state as the owner of gas industry companies. Gas exploration was supervised by the State Geology Committee. The Ministry of Economy regulated gas prices and transportation tariffs.

**Main Challenges and Initial Reforms**

In early 1995 the Ukrainian government faced three major challenges in the gas sector: reversing the decline in gas production, ensuring that only those that paid for imported gas received it, and preserving Ukraine's strategic position on the east–west gas transport corridor in Europe. In 1994 RAO Gazprom announced that a major new line through Belarus and Poland would be constructed to carry gas from the Yamal peninsula to Germany. Early construction of this line would enable RAO Gazprom to divert some of the gas flows that currently go through Ukraine.

The first reform step addressed the problem of declining domestic gas production. Gas production had the potential to increase to 30 billion cubic meters a year following large investments in exploration and production over a period of about five years. But these investments would have to come from abroad because Ukraine lacked sufficient financial resources, technology, and know−how. Recognizing this, the State Geology Committee started awarding exploration (and later, production) licenses to private (mostly foreign) companies in 1995.

The second reform step addressed the problem of inadequate payments for gas imports. Until 1996 Ukrgazprom was the sole importer of gas in Ukraine. This monopoly fit well with the State Oil and Gas Committee's centrally planned approach to balancing gas supply and demand. It also suited RAO Gazprom because import volumes, prices, and payments were negotiated with and guaranteed by the Ukrainian government. But highly subsidized domestic gas prices led to the rapid accumulation of payment arrears in 1992–94.

Even after industrial gas prices were raised to the import parity level in early 1995, the state continued to build up external arrears at an unsustainable rate because payment discipline was poor and state−owned distribution companies were reluctant to cut off delinquent customers. In 1996, under pressure from the International Monetary Fund, the government took a radical step: sovereign guarantees for gas imports were eliminated, and private gas traders were given exclusive rights to import and sell gas to all consumers in specific oblasts assigned to them by the Cabinet of Ministers. With this measure Ukraine became one of the first countries in the world where gas transmission and distribution were unbundled from gas import and supply.

**Continuing Problems**

Awarding exploration and production licenses to foreign companies and transferring responsibility for gas imports to private traders had mixed results. On the positive side, foreign direct investment started to flow to the upstream gas industry, traders managed to improve payment discipline among industrial customers, and the government stopped accumulating additional debt to Russia and Turkmkenistan. On the negative side, none of the main multinational oil and gas companies found the legal and regulatory framework attractive enough to make
large-scale investments in gas exploration and production, the frequent redistribution of supply franchises among traders led to occasional violence and to accusations of corruption, and payment discipline remained low among households, district heating companies, and power plants. Even on external debt, success was only partial. RAO Gazprom claimed that the Ukrainian government was responsible for the arrears accumulated by private traders because the traders were pressured by central and local governments to maintain supplies to politically important customers, and were afraid of losing their franchises if they ignored "national interests." In the summer of 1998 the government accepted responsibility for US$1.37 billion of debt incurred in 1997–98.

Although the system was left largely intact in 1997—the only notable changes were the redistribution of supply franchises in favor of politically influential traders and the permission given to Ukrgazprom to import a limited amount of gas—the need for additional reforms was widely acknowledged. Even Ukrgazprom, a company that had opposed any change in the status quo, argued that it could not ensure the reliability of the transmission system unless it stopped giving gas to privileged consumers at low prices and mostly without payment. In fact, Ukrgazprom should have been the most profitable company in Ukraine in 1997. It produced 14 billion cubic meters of gas at a cost of about US$400 million, about 30 percent below market value. It also received from RAO Gazprom 30 billion cubic meters of gas with a market value of US$1.2 billion to US$1.4 billion as payment for the transit service, while the cost of providing this service was about US$700 million.

Several shippers—RAO Gazprom, a number of gas traders, and a private gas producer—pointed to deficiencies in the tracking and control of gas flows in the transmission and distribution network, deficiencies that made it extremely difficult to enforce commercial contracts between gas sellers and buyers. Potential foreign investors in the upstream gas industry noted the lack of assurances about their access to the transmission and distribution network and their ability to market gas to third parties. A commission created by Parliament to investigate "irregularities" in the energy sector demanded that territorial supply monopolies be abolished and a properly functioning gas market be established.

**Competing Reform Concepts**

Two very different reform concepts emerged in the debate. The first, put forward by Ukrgazprom and the State Oil and Gas Committee, favored increased state control over the gas industry through the vertical integration of gas producers, transporters, and distributors. This setup, it was argued, would improve the flow of revenue from consumers to producers and facilitate the reallocation of profits to priority investments. The second reform concept, developed by the Ministry of Economy, National Agency for Development and European Integration, and World Bank, advocated reduced state intervention through the separation and privatization of Ukrgazprom's production, transmission, and marketing activities, elimination of exclusive gas supply franchises, privatization of gas distribution companies, liberalization of gas prices, and establishment of an independent regulatory body to ensure open access to the transmission and distribution network. Various presidential decrees and Cabinet resolutions issued in 1997 attempted to combine these two concepts into a coherent reform plan, with limited practical results.

A change of government in mid–1997 opened a window of opportunity for those who wanted to eliminate the regional gas import and supply monopolies awarded to selected gas traders. The newly formed Cabinet announced that the gas market would be divided into two segments in the coming year. The first segment, for the import and supply of gas to industrial consumers, would be assigned to private gas traders without any restrictions.
on service areas or prices (figure 3). The second segment, for the supply of gas to households and district heating companies, would be assigned to gas distribution companies selling Ukrgazprom's domestically produced and transit fee gas at prices fixed by the Ministry of Economy. Subsequently, the State Oil and Gas Committee issued requirements that gas traders had to meet to receive import permits. After some relaxation of these requirements, more than twenty traders were authorized to import and sell gas to industrial consumers at freely negotiated prices in 1998.

Meanwhile, the State Property Fund sold the majority of the shares of several gas distribution companies to company managers, employees, and local financial investors at very low prices. The low share prices resulted from a number of factors that deterred strategic investors:

- The assets of the companies did not include the pipelines (since pipelines could not be privatized).
- The rights of the companies to operate and manage the pipelines in the long term were unclear.
- The price of gas marketed by the distribution companies was set at US$66 per thousand cubic meters, including a distribution fee of US$5.34 per thousand cubic meters—barely enough to cover recurrent costs.
- Local governments and influential politicians remained strongly opposed to the curtailment of gas supplies to delinquent consumers.

**Developments in 1998**

Payment collections from households and district heating companies remained low in the first six months of 1998. The newly privatized gas distribution companies kept enough revenue to cover their wages and other recurrent costs and sent what was left to Ukrgazprom. Still, Ukrgazprom's financial situation continued to deteriorate. The supply to industrial consumers was at risk because few traders were sufficiently creditworthy to purchase gas from RAO Gazprom. Nevertheless, price liberalization led to a significant drop in the prices paid by large consumers, particularly when part of the payment was in cash.

In early 1998 supporters of a vertically integrated industry structure focused their efforts on establishing Naftogaz, a company whose assets would include everything that the state owned in the oil and gas industry. It was argued that Naftogaz could solve the problem of low payment collec—
tion because it could take away the right to manage and operate distribution assets from gas distribution companies that performed poorly. Its supporters also claimed that Naftogaz could increase foreign direct investment in oil and gas production because it could enter the assets of its oil- and gas-producing subsidiaries into joint ventures (until then, only the State Property Fund was authorized to privatize these and other gas industry assets). Finally, supporters claimed that Naftogaz could provide funding for priority investments because it could reallocate profits among its subsidiaries.

These arguments were apparently accepted by all the relevant government agencies, and in February 1998 a presidential decree ordered the government to establish Naftogaz. Naftogaz can also be seen as an attempt by the government to regain control over the privatization process in the oil and gas sector in response to the increasing influence of the Parliament over the State Property Fund. As a gesture to those who argued for separation rather than integration, the presidential decree also ordered the implementation of organizational steps to unbundle gas production, transmission, and supply functions, although this unbundling was expected to take place within the framework of Naftogaz. A government resolution issued in June approved the charter of Naftogaz and appointed its chairman and supervisory board.

In a May 1998 meeting to discuss the recommendations of a World Bank–government working group on gas reform, advocates of the second reform concept argued that the nonpayment problem could not be solved unless the management of transmission and distribution assets were transferred to strategic investors, that controlling corruption would require introducing a transparent, cash-based gas marketing mechanism, and that full-scale privatization (rather than joint ventures) was needed to revitalize domestic gas production. At the end of the meeting agreement was reached on an action plan that included, among others, the following steps to be taken during 1998–2001:
Setting up in 1998 of a state−owned joint stock company to operate the transmission network, and appointment in 1999 of a consortium of domestic and foreign companies to manage the shares of this company for at least fifteen years. State ownership in the consortium will be limited to 25 percent plus one share. The allocation of transmission capacity will be market−based, ensuring equal treatment of all domestic shippers.

Introduction in 1999 of incentives and criteria to improve the collection performance of gas distribution companies. Where performance is poor, rights to operate the distribution system and supply gas to nonindustrial customers will be transferred to other entities (domestic or foreign) with a proven track record.

Starting in mid–1998, organization of quarterly gas auctions where gas traders and large consumers can purchase gas from Ukrgazprom for cash.

Improvements in 1998–99 in the metering, tracking, and balancing of gas flows, including the introduction of contractual arrangements for the settlement of differences on a daily and monthly basis.

Separation and privatization of the gas production activities of Ukrgazprom and the gas exploration activities of the State Geology Committee.

If implemented, the action plan will go a long way toward restoring the financial health of the gas industry, increasing budget revenues, addressing the complaints of investors in gas exploration and production, and ensuring the reliable transit of gas from Russia to Central, southern, and Western Europe. Several well−connected parties will be negatively affected, however. Private traders, for example, may lose their best customers when financially liquid industrial companies can purchase their gas at auctions. Central and local governments will be much less able to ensure the supply of gas to cash−strapped budgetary entities and public utilities. Managers who cannot adapt to a market environment and workers who are redundant will lose their jobs. Government officials who benefit from nontransparent gas trading arrangements will also be worse off.

To date, government performance in implementing the action plan has been mixed. The first gas auction, in the summer of 1998, failed because of a high preset minimum price and limited advertisement. Half a billion cubic meters of gas were sold at a subsequent auction shortly afterward at a slightly lower minimum price. At the third auction, in late October, just 9 million cubic meters of gas were sold for US$37 per thousand cubic meters (equal to the minimum price), reflecting the weakening demand for gas due to the recent depreciation of the hryvnia and a downturn in the economy. It remains to be seen whether the government (or its agent, Naftogaz) will be willing to lower the minimum price in order to sell more gas through auctions.

In September 1998 Ukrgazprom and Ukrgaz were reorganized into three companies: a gas transportation company that owns transmission and distribution assets, a gas trading house, and a gas production company. All three companies, however, remain under Naftogaz. Preparations have not started for the privatization of the gas production company and the award of a longterm management contract for the gas transmission system.

A presidential decree ordered the transfer of responsibility for regulation of the gas industry from the Ministry of Economy and the State Oil and Gas Committee to the National Electricity Regulatory Commission (although the Ministry of Economy will continue to set household gas prices for a limited period). Given the time required to recruit gas specialists and implement necessary organizational changes, the regulatory commission is not expected to be ready to discharge its new functions until mid−1999. The State Oil and Gas Committee, having been stripped of its ownership and regulatory functions, has refused to go out of business without a fight, and is lobbying for the preservation of its technical (that is, noneconomic) regulatory functions.
Lessons

Because gas reform in Ukraine has had no blueprint, its direction has remained ambiguous. That ambiguity is the result of a conflict between those who advocate vertically integrated, opaque, monopolistic structures and those who want a transparent, competitive gas market governed by stable rules. The probability is low of a strong jolt—such as a significant and lasting curtailment of Russian gas deliveries to Ukraine to stop the accumulation of payment arrears—signaling the need to end the "unholy" alliance between politicians and gas traders. (Russia, at least in the short term, has no alternative route to European gas markets.) Thus the conflict between those supporting reform and those opposing it will likely continue for several years. Eventually, however, Russia will likely have one or two alternatives to the unreliable Ukrainian transit system, creating strong incentives for players in the Ukrainian gas industry to clean up their act.

A number of lessons emerged during the first three and a half years of gas reform. These may be of use for reformers in the former Soviet Union and elsewhere:

The apparent contradiction between an externally imposed goal—that state guarantees for gas imports should be eliminated—and the conviction of domestic decisionmakers—that the government's operational control over the gas industry should be preserved—was resolved by introducing private regional supply monopolies. Although the new arrangements reduced the state's exposure to the risk of nonpayment, this benefit came at a high cost. A few politically connected traders captured a large part of the gas market, corruption skyrocketed, and the moral authority of the government eroded.

Ukrgazprom's ability to absorb the cost of nonpayment for domestically produced and transit fee gas without catastrophic consequences (at least in the medium term) reduced decisionmakers' sense of urgency to initiate reform, demonstrating that gains do not motivate governments as strongly as do actual losses.

The regulatory, taxation, and market access difficulties experienced by the first investor in gas exploration and production strongly deterred other potential investors despite favorable drilling and production conditions.

The sale of the majority of the shares of the gas distribution companies to workers and managers did not solve the payment collection problem. In the absence of strategic investors, the companies continued to lack the commercial focus, experience, and independence needed to stand up to political pressure and aggressively pursue delinquent households, public utilities, and budgetary entities.

The liberalization of gas supply provided certain immediate benefits to industrial consumers, but the development of a vibrant competitive gas market requires clear network access rules, better metering, tracking, and balancing of gas flows, and new contractual arrangements.

Even the first step toward a spot market—setting up a system of occasional gas auctions—requires strong political commitment to overcome opposition from suppliers and traders that stand to lose customers.

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Trends and Markets in Liquefied Natural Gas

Rob Shepherd

"It was the best of times, it was the worst of times, it was the age of wisdom, it was the age of foolishness, it was the epoch of belief, it was the epoch of incredulity, it was the season of Light, it was the season of Darkness, it
was the spring of hope, it was the winter of despair, we had everything before us, we had nothing before us ..."
Quoting the opening of Charles Dickens's *Tale of Two Cities* in connection with the current state of the liquefied
gas (LNG) industry may, if anything, be overly optimistic, beset as the industry is with low prices and
stuttering demand in its Asian stronghold. But it is hard to resist calling on these contrasts to characterize the
LNG industry, for despite its problems, there are glimmerings of change that could profoundly improve its lot.

LNG is essentially a niche fuel. Liquefying and shipping gas is expensive, so the LNG route is attractive for
developers only where there is no local market or where capacity in the local market is insufficient to take all the
available local supplies. LNG requires large investments by the buyers in terminal and regasification facilities, so
it generally flourishes only where there is a shortage of indigenous gas supplies and where competition from
pipeline gas is limited. In bulk, LNG is suitable for transport only by sea, so its use in landlocked areas is
confined to small peak shaving plants or isolated locations such as central Australia.

Not surprisingly, there are only a handful of LNG projects, and most supply East Asia, which lacks indigenous
resources (table 1). But the earliest LNG supplies went from Algeria to Europe and the United States. Europe still
takes significant quantities (just under a quarter of world demand), and the United States receives a trickle (soon
to be augmented by the startup of the Trinidad project).

LNG commands a significantly higher price in Japan, the Republic of Korea, and Taiwan (China) than it does in
Europe or the United States. So more supply has been economic to develop, and since the Pacific Rim has both
ample gas reserves and limited local markets, that region dominates LNG trade, with more than three-quarters of
total supply.

**In LNG, History Matters**

To find the roots of the current situation, it is necessary to go back to the 1980s. The 1970s had been years of
expansion for LNG, and by the end of the decade Japan was receiving LNG from Alaska, Brunei, Abu Dhabi, and
two Indonesian plants at Arun and Bontang, all under long-term take-or-pay contracts closely tied to crude oil
prices. The first Malaysian plant was under construction and would start up in 1983. But the second oil shock of
1979 and the restructuring it engendered set back demand in Japan. The buyers—particularly the power
companies—found out just how rigid those long-term take-or-pay contracts could be. They took the full volumes,
but were not happy. New LNG became difficult to sell. The Australian project did not come on stream until 1989,
after significant delays. By that time oil prices had dropped, Japan had recovered, and power demand in the
country was growing so rapidly that it could be met only by building gas-fired power plant. Suddenly LNG was
in demand again. Korea, in 1986, and Taiwan (China), in 1990, had begun to take LNG, having bought
incremental capacity from the Indonesian

<table>
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<tr>
<th>Current Country</th>
<th>Potential Country</th>
<th>Current Project</th>
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<tr>
<td>Algeria</td>
<td>Pacific</td>
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<td>Australia</td>
<td>North West Shelf</td>
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**TABLE 1**

**CURRENT AND POTENTIAL LNG SUPPLIES**
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<tr>
<th>Country</th>
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<td>Brunei</td>
<td>Brunei NWS Expansion</td>
<td>Indonesia</td>
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<td>Malaysia I and II</td>
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<td>Oatargas</td>
<td>Russian Federation</td>
<td>Sakhalin 1</td>
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<td></td>
<td>Ras Laffan LNG a</td>
<td>Russian Federation</td>
<td>Sakhalin 2</td>
</tr>
<tr>
<td>Trinidad and Tobago</td>
<td>United States</td>
<td>United States</td>
<td>Alaska North Slope</td>
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<td>Atlantic LNG a</td>
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<tr>
<td>United States</td>
<td>Kenai (Alaska)</td>
<td>Caribbean basin</td>
<td>Atlantic Expansion</td>
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<td>Nigeria</td>
<td>Third Train</td>
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<tr>
<td></td>
<td></td>
<td>Trinidad and Tobago</td>
<td>Atlantic Expansion</td>
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</tbody>
</table>

a. Expected to start production in 1999.

The Korean market began growing at a phenomenal rate.

The resurgent demand was met largely by expansion of existing plants. A second plant was constructed in Malaysia alongside the first, and Bontang continued to be expanded. All the other existing plants managed to squeeze out more LNG. Why were no new plants built? For three main reasons.

First, the cost of constructing LNG plants had risen sharply. Because few plants are built, there are few contractors and process licensors with a proven track record, and thus little competition. High LNG prices before 1986 and the emphasis on reliability of supply reinforced this tendency. Buyers and project sponsors insisted on proven technology and experienced contractors. Designs were lavishly gold-plated (an LNG plant can often produce at least 15 percent more than its nameplate capacity, and Australian and Malaysian plants routinely produce 25 percent more). Greenfield plants also seemed uneconomic when compared with expansion, particularly after the fall in oil and LNG prices in 1986. While an expansion might need only marginal additional investment, a greenfield LNG plant involves not only a central gas processing unit, but also site preparation, harbor, marine, tankage, accommodation, utilities, and the general infrastructure to establish and support the operation in a remote location.

Second, an expansion does not have the same scale problems as a greenfield project. A typical liquefaction train by the late 1980s was about 2.5 million metric tons (3.5 billion cubic meters) a year—a volume that the market could easily digest. But the minimum scale for economic viability on a new site had come to be seen as 6 million metric tons a year—a much harder prospect to place even in quickly growing markets.
Third, speed was important, and it is quicker to expand existing plants than to build new ones. LNG projects are extremely complex, and it normally takes at least two or three years to set up the venture structure of a new one.

By the early 1990s all the expansion possibilities had been soaked up. By this time, encouraged by the buoyant demand if not by the prevailing prices, several new projects were emerging, mainly in the Middle East. Project sponsors were heard to say that the buyers needed the LNG and that prices would therefore have to rise to make new projects economic. Qatargas, based on the enormous reserves of Qatar's North Field, got in ahead of any real competition and sold 4 million metric tons a year to Chubu Electric in Japan, quickly followed by 2 million more to seven other Japanese buyers. It had started up in 1997, eight years after the last greenfield project in Australia, and was supported by a guaranteed minimum price (or so it appeared).

Not surprisingly, buyers were resistant to higher prices, and Japanese power companies shifted their preferences toward coal. Some of the project sponsors started to consider whether costs could be reduced to make greenfield plants economic without increasing prices.

Then demand growth started to ease, at least in the Japanese market, coming to a crashing halt in 1998. Yet gas continued to be found, and prospective projects to increase. By 1995 it had become apparent that there was more LNG than the traditional markets could absorb. Projects would have to become more competitive and find new markets. Nevertheless, on the strength of soaring Korean demand, two new projects, Oman LNG and Ras Laffan, will start up this year.

Meanwhile, there was at last some activity in the Atlantic basin. After some thirty years of trying, the Nigerian project finally began to supply LNG buyers in Europe. And a rejuvenated Trinidad project will supply the U.S. market as well as Spain. All four projects point in new directions, and the rest of this Note focuses on where they might lead us.

**Potential Supply—And its Implications**

More than 100 million metric tons a year of potential LNG is seeking a market. Given open markets and enough finance, the industry could more than double in size in half a dozen years.

The traditional markets in Asia will be unable to absorb the potential supply before 2015—or even 2020. The Pacific projects, all advertising startup dates between 2001 and 2005 (though with varying degrees of unreality), face an unpalatable prospect. The performance of an exploration company depends not only on its ability to find oil and gas but also on its ability to commercialize discoveries as rapidly as possible. In a highly capital-intensive industry the discount rate relentlessly ticks away value. Something must be done to rescue the projects. Three conclusions are emerging.

First, the projects must be made more competitive, not just with one another but now also against low oil prices. This conclusion is being accepted only reluctantly. LNG projects have scarcely had to compete with one another in the past and have generally had little problem competing with oil at US$18 or more a barrel. For most of the life of the LNG industry the available gas barely sufficed to meet the needs of importers. Competition takes three main forms: competing on cost, offering more market–friendly terms, and calling on established buyer relationships.

Second, new markets must be opened up. Oman LNG tried to open a new market in Thailand but ultimately failed against competition from pipeline gas imports and the contracting economy. The emphasis is now on India and China.
Third, producers can get out while the going is good. BP is the only producer to have done this, selling its gas resources in Papua New Guinea. Two other projects, Pac Rim in Canada and Cristóbal Colón in Venezuela, have stopped trying to market LNG, having failed to put economic schemes together. In all these cases there are possible alternative uses for the gas.

**Finding Ways to Compete on Cost**

LNG is forced to be more competitive in the Atlantic trade than in the Pacific. There is competition from pipeline gas in the target markets in Europe and the United States, and prices are lower than in East Asia. Not surprisingly, the Nigerian and Trinidad projects lead the way in the pursuit of low cost.

**Shipping**

Nigeria's main innovation was to use idle ships. For many years there has been a pool of unemployed ships, built speculatively on the assumption that a spot trade in LNG would develop, or freed up by the failed Algeria–U.S. project or the failed Indonesia–California project. Because buyers in Japan insisted on new ships for new trades, the ships languished except for occasional shortterm charters.

Shell acquired some of these ships cheaply for Nigeria LNG at the end of the 1980s–well before the project needed them, as it turned out. It was a brave move that paid off handsomely in the end. Nigeria LNG earned enough from short−term charters to cover the cost of the ships before they reached Nigeria. And high demand for LNG in Japan and Korea that could be supplied from spare capacity in existing LNG plants created a need for ships that Shell was only too pleased to fill.

The Trinidad project has also benefited from the use of secondhand ships, two retired from the Phillips Marathon Alaska–Tokyo route, one from the Abu Dhabi project, and one of the U.S. Marad ships, now owned by Trinidad partner Cabot. But under normal conditions, cheap secondhand ships are not necessarily the bargain they appear to be. Usually they have to be acquired well before they are needed, and they need upgrading to ensure that they last for the life of the new project, or at least for much of it. If they then must be laid up for a year or two, the initial cost advantage can be eroded. Moreover, the number of used ships available has declined, while the demand has increased to the point where the benefits of used ships have virtually disappeared.

**Plant Cost**

Although BP was probably the first to call attention to the need for improving the cost and economic performance of new LNG schemes, Trinidad made the real breakthrough. Although new to LNG exports, the Trinidad partners were determined not to build a high−cost plant. They applied the cost savings lessons that low oil prices had forced on offshore developments in such high−cost areas as the North Sea. At the same time Phillips, with Bechtel, was attempting to market an updated version of the cascade liquefaction technology developed for the early Alaskan plant and not used since. The Trinidad team not only produced a design suited for the purpose, it sought bids for two front−end engineering design contracts, one for the Phillips technology and the other for the APCI process that has been used for all other recent plants. This strategy enabled it to obtain truly competitive bids for the main contract for plant construction.

The results were startling. All the bids came in at less than US$250 per metric ton a year of installed capacity–30 to 40 percent less than the costs in the late 1980s. The Phillips cascade technology probably had little to do with the low bids. The real breakthroughs were in design philosophy and, perhaps most important, in engendering real competition among the contractors. In most LNG projects the construction contract goes to the contractor that carries out the front−end engineering design because of its significant information advantage. And since there are
few contractors, the advantages of bidding have been limited.

The producers in the Pacific basin do not seem to have fully absorbed the lessons of Trinidad, although both RasGas and Oman LNG benefited from relatively low bid prices, possibly from contractors trying to avoid losing out again. Shell, probably the leading LNG supply company, is pursuing its own route to cost reduction, largely through scale economies. It is talking of single liquefaction trains approaching capacity of 4 million metric tons a year. Not only is this an unwieldy scale for a project, Shell also appears to be struggling to get costs down to US$250 per metric ton a year.

Financing

Financing has seen some innovation, although not all the developments have been positive. Even with highly creditworthy buyers, most of the early LNG projects were equity (or at least shareholder) financed, and it was generally large oil companies that developed LNG schemes. More recently project financing has increased, presumably because companies with smaller balance sheets are becoming involved. Project financing is not a cost savings route and is also time consuming. Nigeria LNG gave up its attempts to raise project finance and reverted to equity financing. RasGas moved to bond financing, raising US$1.2 billion on the U.S. bond market at remarkably good rates. But Korea's economic problems and the decline in its debt rating have led to a downgrading of the bonds' rating (although not below investment grade), with a corresponding impact on their price. The bond route has probably closed for LNG finance, at least temporarily. Oman LNG had intended to go that route but changed course after the East Asian financial crisis.

Opening New Markets

With demand low in the main East Asian markets, the industry has tried to open up new markets in Asia. India and China have always been seen as the main prizes, though the first progress was in Thailand, where Oman LNG and RasGas tried to sell LNG. Price was a sticking point: pipeline gas set a marker, and Thailand wanted indexation linked to coal for power generation. Oman LNG proved more flexible on this point and a deal was concluded in principle, only to be overturned as more pipeline imports appeared and Thai demand collapsed.

Attention shifted to India and China, but both present formidable obstacles to establishing a market for LNG. In traditional markets LNG can rely on powerful, creditworthy buyers that can underwrite a twenty-five-year take-or-pay contract. No such buyers exist in the new markets. Neither country has a fully convertible currency. There is virtually no gas infrastructure, particularly in the target areas for LNG. But there is huge potential demand, particularly in power generation, a sector in crisis in both countries. With the traditional route to developing LNG trades closed, a new way of conducting business had to be found.

Initially, supply to independent power producers (IPPs) in India was expected to be an easy market to develop. But finance proved to be an obstacle. IPPs are generally project financed and rely on long-term electricity sales contracts. In India most state electricity companies supply electricity below cost to the rural sector and are loss making. The federal government is unwilling to issue sovereign guarantees. And the complexities of dual project financing—with an IPP at one end of the chain and a new LNG development at the other, and with different borrowers—are probably insurmountable.

A second obstacle was the lack of gas infrastructure in all but a limited area. There was no obvious strong utility company to buy LNG and develop the nonpower market. LNG sellers would probably have to get into local marketing, but while they were prepared to invest in receiving terminals, few were willing to go much further. Yet LNG imports were unlikely to be limited to power demand: even with a serious shortage of electricity, demand at any one location would not grow fast enough to fully load an LNG terminal (or a large LNG plant) quickly.
enough.

Complicating the situation in India, the host governments have tended to put the cart before the horse, calling for tenders for LNG supply before tackling the market absorption and finance questions. Because of the complexities of LNG development, no tender can be unconditional on either side; usually there are major reservations by both parties over financing, timing, and commitment by the other side. So the process has been of dubious value, at best only an invitation to negotiate.

Enron’s scheme to supply Dabhol Power Company, in India, will probably be the first LNG supply in either India or China. It appears that this scheme will be able to use the tested method for opening new Asian LNG markets—taking spare capacity from existing projects, in this case Oman and Abu Dhabi. The suppliers will probably have to take more risk and provide more contract flexibility than in traditional contracts. The saving graces: the demand is apparent, and the state is prepared to give some support to the state electricity board.

Enron will have a major stake in the receiving terminal and power plant, but not in LNG supply. The company also plans to market gas to other industries in the region. Financial closure, the key step, is reported to be imminent.

Elsewhere in India, a different approach is being tried by the Petronet group, which includes most of the largest oil and gas companies in India, presumably in an attempt to assemble stronger creditworthiness. This group called for tenders to supply 7.5 million metric tons a year and to be involved in the receiving terminals at several locations. RasGas won the bid and is reported to be moving toward a sales contract. But the scheme raises all sorts of questions and there is a long way to go. A major expansion for RasGas, it will have to be financed, and the two sides will have to work out an acceptable way of distributing the risks. Even so, with Qatar boasting in December of 4 million metric tons a year of spare capacity, even the Petronet project will not rely entirely on new LNG. RasGas also won a bid for the Tamil Nadu state project planned for Ennore (this time as the fuel source for a group interested in investing in the terminal and associated power plant).

That all the supplies for India originate in the Middle East is not insignificant. The shipping distance to India is considerably shorter from the Gulf than from any of the Pacific Rim projects (except Arun to Ennore). Competition among Gulf producers should keep their f.o.b. (free on board) prices close to the equivalent netback from traditional buyers, making it unattractive for Pacific–based projects to compete in the Indian market. But the Gulf–based projects suffer a freight disadvantage in supplying Japan and Korea.

Less progress has been made in China, despite intensive study of the market by several potential suppliers, including Shell and Mobil. Most attractive is the fast–growing coastal strip between Guangdong and Shanghai. With Shanghai now appearing to be within economic reach of pipeline gas from Siberia, the focus has shifted to the Guandong area. The government has said that it favors LNG imports and has called for a major feasibility study, but nothing will happen until this study has been completed. The stronger central control in China lends a different flavor than in India, but many of the same issues will have to be faced and there seems to be no prospect of central government guarantees to support imports.

**Weathering Liberalization in Established Markets**

In the Japanese market the effects of the economic downturn on energy demand and LNG prices may be short term and coped with fairly easily, but the effects of liberalization in the gas and, particularly, the power sectors are essentially unpredictable. Power buyers in particular cannot be sure of their future market share, which makes it distinctly risky for them to make long–term take–or–pay commitments and favors fuels that can be purchased as and when needed. Small wonder that Japanese buyers have apparently decided to take on minimal new...
long–term LNG commitments. But this is largely a problem of transition. In the long run a liquid spot market should remove the volume risk even for gas, as it has in the United States. Even so, it takes years for such a market to develop, and LNG sellers could face a decade of uncertainty. The future is further clouded by the emissions reduction obligations Japan accepted at Kyoto, which

tend to put fuel choices in conflict with those that follow from liberalization.

The Korean LNG market—highly seasonal and bedeviled by conflict between the two users of LNG, KEPCO (Korea Power) and KOGAS (Korea Gas)—has suffered a decline that has been exacerbated by the conflict. This decline led to rephasing of some contracted purchases and to concern about Korea's capacity to absorb contract volumes from Rasgas and Oman LNG that start this year. But Korea, which has done more to put its economic house in order than most countries in the region, should be able to meet its contractual obligations.

In Korea too liberalization is in the air, but the timing and extent are uncertain. POSCO, a major steel maker, will be allowed to build a terminal and import LNG for use in electricity generation, mainly for its own use. Whether POSCO will cooperate with KOGAS to avoid worsening the problems of temporary oversupply and seasonal storage remains to be seen. KOGAS has been planning a third terminal of its own, and there seems no need for both this and a POSCO terminal. Nor does there appear to be any immediate need for newly contracted supply to meet POSCO's requirements. The problems of seasonal supply and demand could be addressed in several ways, including introducing interruptible industrial tariffs that would reduce summer valleys and thus increase total supply. And there is inherent unsatisfied demand that new initiatives could uncover.

Taiwan (China) has suffered little from the economic disturbances in the region. Here too there are thoughts of energy liberalization. There are also new IPPs, and severe strains in the relationship between CPC, the government–owned monopoly operator for both oil and gas, and Taipower, the government–owned power utility. Political positions will take time to unravel, and as the future growth of LNG supply depends largely on the timing, cost, and ownership of the proposed second LNG terminal, the watchword is "wait and see."

European gas markets are also under pressure to liberalize—pressure that is being strongly resisted in some quarters. Liberalization does not sit easily with the traditional way of trading LNG, which relies heavily on long–term contracts and take–or–pay. In the longer run, with liquid trading systems removing volume risk, long–term contracts and take–or–pay can be combined with a floating gas market price, but the uncertainties of the transition are unsettling. Moreover, liberalization usually pushes prices down—an uneasy prospect for a high–cost source of supply.

**Price Wars?**

LNG pricing is an area where novelty and tradition are likely to come into conflict—with unpredictable results.

In Europe LNG needs to compete with pipeline gas at the point of entry, and current prices are low enough to frighten all but the very brave or foolhardy. The big questions for the future are how long gas prices will be coupled to oil prices in continental Europe and what will happen to gas prices when there is a decoupling. In North America and Britain decoupling has tended to reduce prices.

In Asia the pricing signals also point to innovation, and perhaps confusion. After nearly three decades in which prices in Japan, Korea, and Taiwan (China) moved in parallel (under the general control of Japanese buyers), there are now seeds of real competition among suppliers. The "floor price" that was essentially agreed for Qatargas supplies has already been dropped (RasGas dropped a parallel provision for Korea in order to enlarge the supply contract), and the recent results of price renegotiation with existing suppliers suggest that the apparently inexorable upward creep of prices has been halted and probably reversed.
The traditional pricing formulas ensure that LNG becomes less competitive with oil at low oil prices, causing gas companies to suffer and discouraging power companies from using any more LNG than their contracts call for. If low oil prices persist, there may be pressures for price changes that are difficult to resist. And if East Asian buyers overcome their reluctance to buy new LNG, competition could result in a new, more buyer–friendly deal, giving established buyers a new yardstick and a reason to renegotiate across the board.

East Asian pricing structures may also come under strain as a result of deals in India, where novel pricing structures and levels are being proposed. For example, the winning bid for Ennore is reported to offer LNG at a fixed price, a rather eccentric choice. Indexation, which is more closely tied to real competition in the end use market, must be a real possibility. The ultimate end is a price linked to gas prices in a liberalized and liquid gas market (as in the United States). But this is a long way off, and how the industry gets there will be interesting to watch.

Will Spot Trading Develop?

So far there has been no real spot trading in LNG, although there have been many short–term deals between established buyers and sellers based on spare plant and shipping capacity. Nevertheless, several forces could lead to more extensive trading that might just result in a spot market.

The first is the Korean seasonality problem. Gas demand in Korea has a strong winter peak, but LNG contracts require even deliveries through the year. This can be handled in part (though expensively) by storage. But the growth of the Korean market has threatened to exceed the storage capacity and the country has run perilously close to stock–outs in winter. Much of the Korean supply has been based on short–term supplies, and these can be biased toward winter, although not without diverting some cargoes originally intended for Japan. Japanese buyers have been reluctant to participate in swaps, but in the current market stress Osaka Gas has provided Korea with a winter cargo this year. There is an obvious synergy with Taiwan (China), where the load peaks in summer, but the buyers have not organized to take advantage of it yet. There is also much potential for freight saving deals (although the benefit is not easy to capture). Clearly, a more flexible trading pattern would benefit both buyers and sellers, but extreme caution, particularly among the Japanese buyers, has inhibited its development.

The opening of new markets such as India could also lead to a more flexible trade. The players in the chain have to accept more risk that the market will not perform as expected. To deal more flexibly with the Indian market, they may look at alternative ways of disposing of surplus LNG or acquiring LNG on short notice. But for this to be a real option requires a market of last resort. In winter there is generally a market in Europe that could absorb some surplus LNG at a reasonable price, as long as there is shipping capacity to get it there. The only truly liquid gas market, however, is in the United States. It is probably too far and its price too low to support an Indian or Pacific traded market, but it could provide the Atlantic trade with yet another opportunity to innovate. There are signs that this opportunity is being exploited. Cabot, one of the Trinidad partners and also the U.S. buyer of Trinidad gas, has on–sold part of its supply to an IPP in Puerto Rico promoted by Enron. Thus a new market has been opened using LNG whose development was underwritten by a sale into the United States. This might eventually evolve into a much more flexible trade, although there are still many obstacles to overcome, not least the availability of adequate shipping capacity.

Conclusion

These are obviously difficult times for LNG. But they are also exciting times. Difficulties lead to new ideas and to attempts to rewrite the rules. Not all these efforts will succeed, of course, but there is certainly plenty to maintain the interest in the LNG business today.
Argentina’s natural gas industry was privatized at the end of 1992. Prior to divestiture, the state-owned monopoly Gas del Estado was divided into two transport and eight distribution companies, all of which were sold through international bidding.

An independent government body, Ente Naal Regulador de Gas (Enargas), was established to regulate the transport and distribution segments of the industry. As part of its mandate, Enargas is in charge of price reviews. These reviews, which occur every five years, determine the allowed tariffs for each transport and distribution company. The first such review took place in 1996–97, and the new tariffs went into effect in January 1998. This Note examines the methodology and outcome of this experience.

The Enargas price review is of interest for several reasons. First, it is the first of its kind in Argentina, and one of the first in a developing country. The outcome of the process provides a test of the regulatory framework adopted by the Argentine government, and may influence regulatory reform in other parts of the world. Second, as the first such event, the 1996–97 review set a precedent for methodologies and approaches to be used in future utility price reviews in Argentina. Finally, the approach used to calculate the cost of capital— as well as the other parameters used to set prices—provide an interesting illustration of how theoretical and practical methods from regulatory practice in industrial countries can be adapted to developing countries, where data availability and other restrictions prevent a direct transfer of techniques.

The Regulatory Framework

The tariff paid by final gas consumers in Argentina is composed of three parts:

Final price = gas wellhead purchase price

+ transport margin

+ distribution margin

Gas wellhead purchase prices are not regulated, but are determined by the contracts negotiated between gas suppliers and producers. Purchase costs are passed through to final consumers, subject to Enargas’s approval of the prices as reasonable. There is, however, no formal mechanism to promote efficient purchases.

Price margins for transport and distribution are set by Enargas for five-year periods. The price control system is similar to the price cap regulation used in the United Kingdom. But unlike U.K. firms, Argentine firms do not have flexibility in setting individual prices subject to an aggregate revenue or tariff basket constraint. Enargas sets the maximum tariff for all individual services and customer categories. These tariffs must be sufficient to:

Cover operating costs, taxes, and depreciation.

Provide a reasonable rate of return on invested capital.
Guarantee a secure supply by providing resources to fund system maintenance and expansion.

Tariffs are automatically adjusted every six months according to:

\[ g = PPI - X + K, \]

where \( g \) is the percentage change of the tariff, \( PPI \) is the producer price index in the United States, \( X \) is the efficiency factor, and \( K \) is the investment factor, both of which may differ across firms. The last two parameters may also differ for each six-month semester of the five-year period.

The efficiency factor \((X)\) reflects the cost reductions that the regulator estimates can be achieved in the next five-year period, which are thus passed directly on to customers. The investment factor \((K)\) is an adjustment to allow revenues to cover expected investments in improving and expanding network infrastructure. Company investment plans are first screened by Enargas. Once approved, they are assigned \( K \) factors. The \( K \) factors are project-specific and are contingent on the investment being undertaken. They come into effect only after a project has come on stream and is delivering benefits to customers.

**Setting the New Tariffs**

Estimates of future cash flows for each firm are the starting point for the setting of new tariffs. The cash flow analysis should extend until the licenses expire, since this is the relevant time horizon over which owners can recoup their investment. At the time of the review, current licenses were set to expire in thirty-five years.

The net present value (NPV) of a firm's future cash flows is:

\[
\text{NPV} = \sum_{t=1}^{T} \frac{T_tV_t - C_t - I_t}{(1 + r)^t},
\]

where \( T_t \) is the tariff for transporting (or distributing) gas in period \( t \), \( V_t \) is the volume of gas transported (or distributed), \( C_t \) is the operations and maintenance cost, \( I_t \) is additional investment, and \( r \) is the firm's cost of capital.

In the actual modeling of cash flows, \( T \) is a vector of tariffs and \( V \) is a vector of outputs, since there are different tariff zones, different parts to each tariff, and different types of outputs. Another simplification in the above formula is the omission of taxes. Cash flows should be net of taxes, since it is the posttax income that is relevant for the valuation of companies.

To give investors a fair rate of return on their invested capital, the regulator should set \( g \) in equation 1 (and therefore tariffs \( T_t \)) in such a way that the NPV is equal to the capital invested in the firm at the beginning of the review period. This initial investment was set equal to the price paid for the companies at the time of divestiture rolled forward to the review date by adding the new investments made during the interim period and subtracting depreciation.

There is a further issue in determining the time profile of the tariff changes: changes could be gradual—through small changes each semester—or made all at once at the beginning of each five-year review period. Enargas decided that the full price reductions would occur on January 1, 1998. Thus the first \( X \) factor was set to achieve this tariff reduction, while the factor for each subsequent biannual price adjustment was set to zero. This is in contrast to \( K \) factors, which are implemented gradually, as noted above.
Information Requirements

Estimates of the growth in demand (that is, prediction of the parameter $V$ in equation 2) are crucial for determining appropriate tariff levels. Enargas used information provided by other government departments (such as the Secretaría de Energía y Puerto) and the gas companies themselves. The available information was used to construct probable demand scenarios for each firm.

Detailed information on operating costs and revenues, as well as planned investments, was submitted to Enargas by each regulated firm according to a format provided by the regulator (Enargas 1996b).

Productivity increases were considered by the regulator when forecasting costs and, therefore, setting the efficiency ($X$) factor. The exact approach used by Enargas is described below. Investments that expand the network will increase the volume of gas sold and will also affect future cost estimates. These activities are considered when setting the investment ($K$) factor and are also described below.

The Cost of Capital

A fundamental parameter that must be estimated before tariffs can be set is the cost of capital— that is, the cost to a firm of raising an additional unit of capital. Enargas estimated separate rates for the transport and distribution sectors but did not attempt to differentiate these rates across individual companies.

The aggregate cost of capital is a weighted average of the cost of debt capital and the cost of equity capital. The weights are the portion of debt and equity relative to company assets. Formally,

$$r_c = r_d (1 - t) \frac{D}{V} + r_e \frac{E}{V},$$

where $r_c$ is the cost of capital, $r_d$ is the nominal interest charged on the firm's debt, $t$ is the profit tax rate faced by the firm (0.3 in Argentina), $D$ is the debt of the firm, $r_e$ is the opportunity cost of equity capital, $E$ is the value of the firm's equity, and $V = D + E$. Debt and equity are measured by their market value. Where a firm's debt or shares were not traded in the market, information from financial statements was used. The equity and debt figures for the Argentine gas industry at the time of the review are presented in table 1. The final nominal and real capital costs for transport and distribution, as calculated by Enargas, are presented in table 2.

The cost of equity capital. The cost of equity capital must include a risk premium to compensate investors for the nondiversifiable volatility of the financial returns on a firm's equity. The higher the volatility, the higher the expected rate of

| TABLE 1 |
| DEBT AND EQUITY IN THE ARGENTINE GAS INDUSTRY, 1996–97 |

<table>
<thead>
<tr>
<th>Activity</th>
<th>Debt</th>
<th>Equity</th>
<th>Debt to equity ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transport</td>
<td>874</td>
<td>1,152</td>
<td>0.58</td>
</tr>
</tbody>
</table>
return investors will demand to hold the asset. Calculating this risk premium for a regulated utility is a necessary but contentious aspect of any price review. A widely used tool in this endeavor is the capital asset pricing model.

Use of the capital asset pricing model is problematic in countries where stock markets are underdeveloped or where the industry under analysis has not historically been quoted on the stock exchange. This was the case in Argentina. Only two of the ten gas firms had been quoted on the stock exchange at the time of the review, and even for these companies, the time series for stock market data was rather short. Recognizing these obstacles, Enargas used the following adjusted capital asset pricing model:

\[
\begin{align*}
     r_e &= r_f + \beta_e (r_m - r_f) + \text{riskARG},
\end{align*}
\]

where \( r_e \) is the cost of equity for an Argentine firm, \( r_f \) is the return provided by a risk-free asset in a reference industrial country, \( r_m \) is the return on a well-diversified portfolio in the reference country, \( \beta \) is a parameter proportional to the covariance between the return on the equity of the gas firm and the return on the diversified portfolio in the reference country, and riskARG is a premium reflecting Argentina's sovereignty risk. Except for the last term, the above formula is the standard capital asset pricing model.

The risk-free interest rate (\( r_f \)) was taken to be the yield to maturity on U.S. Treasury bonds of the same average life as the Argentine gas companies. The sovereign risk premium (riskARG) was obtained by comparing the rate of return of a foreign currency-denominated Argentine bond with that of a U.S. Treasury bond. Enargas used Argentine euronote bonds as the basis for comparison. These bonds are denominated in U.S. dollars and in deutsche marks and were issued by the Argentine government in European financial markets. The risk premium of a well-diversified portfolio (\( r_m - r_f \)) was estimated as the difference between the return on a basket of stocks in the United States and the rates on U.S. Treasury bonds with long maturities.

The final parameter needed is the beta coefficient (\( \beta_e \)). This parameter is proportional to the correlation between the returns on the firm’s equity and those on the market portfolio. Estimated betas were available in the United States only for gas distribution companies. The average beta coefficient for these companies was 0.58 (Enargas 1996a). The estimated beta coefficients for the United States were adjusted for two factors before being applied to
Argentina. Both adjustments relate to differences in the risk characteristics of the companies in each country:

First, the financial gearing of a firm will influence the beta coefficient. Unless firms in Argentina have the same financial gearing as firms in the United States, the beta coefficients for U.S. firms are not applicable to Argentine firms.

Second, gas distribution firms in the United States are regulated by a rate−of−return system. This regulatory regime may be considered inherently less risky for investors than the price cap regime practiced in Argentina.

An adjustment for the first factor requires the use of a formula that relates the beta coefficient to the gearing ratios of firms. Details on this adjustment can be found in Enargas (1996a). The adjustment for the differences in regulatory regimes is undertaken by examining the beta coefficients for firms regulated under different regimes in Britain and the United States.

The final result was an average beta coefficient for Argentine gas distribution companies of 0.78. For gas transport companies there was no equivalent information on beta coefficients from the United States. Instead, the parameter for this sector was obtained by rescaling the beta coefficient for the distribution sector by the relative standard deviation of the returns to each type of activity in Argentina. (Details can be found in Enargas 1996a.) The result is an estimated beta coefficient for gas transport companies of 0.58. This accords well with prior expectations. Gas transport is less risky than the more competitive distribution sector, and so should have a lower risk premium.

The cost of debt capital. The cost of debt capital was estimated as $r_f + \text{risk}_{\text{ARG}}$, the sum of the risk−free interest rate (measured by the rate of return on U.S. Treasury bonds of similar average life as the Argentine gas firms) and the sovereign risk premium for Argentina. The cost of debt capital amounted to 12.56 percent for transport and 13.02 percent for distribution.

**Determining the Efficiency Factor**

Enargas analyzed three sources of information on potential efficiency gains to forecast costs and set efficiency ($X$) factors:

- Efficiency−enhancing project and restructuring plans submitted by the firms.
- Global productivity trends in the industry.
- Financial models to check the consistency of results.

Legislation requires Enargas to identify and quantify the impacts of specific efficiency projects as a basis for setting the $X$ factors. To that end Enargas, with the help of independent consultants, analyzed detailed programs that allowed for reliable estimates of efficiency gains. Examples included inventory control programs, changes to firms' input purchasing strategies, and changes in billing systems.

In this respect, the legislation requires Enargas to adopt a method that requires detailed knowledge of the management of firms, and thus contradicts the spirit of arm's−length regulatory control. The problem with this approach is that asymmetric information prevents the regulator from identifying all the efficiency improvements that a company could introduce and that, moreover, not all efficiency gains can be linked to specific programs. For these reasons, Enargas also analyzed historical total factor productivity in setting the $X$ factors. However, since license conditions required that the $X$ factors be based on clearly identified and quantified projects, Enargas
had to expend some legal effort in justifying the application of total factor productivity analysis in setting the factors.

The final $X$ factors for each company are shown in table 3. These factors are applied once at the beginning of the five–year period. Thus on January 1, 1998, tariffs were reduced by the full amount of the efficiency factor.

**Determining the Investment Factor**

Investment ($K$) factors, if positive, increase tariffs each semester. Their purpose is to stimulate investment in improving and expanding the gas system. Investment projects are approved by Enargas if they:

- Have reasonable costs and schedules.
- Cannot be funded with the original tariffs and so require additional investment.
- Expand the system—maintenance investment is considered when setting the efficiency ($X$) factor—and improve the quality and security of supply beyond the requirements stipulated in the license conditions.
- Benefit the majority of the firm's customers.
- Are structured so that companies assume all construction cost risks.

The transport and distribution companies presented investment projects worth 1,774 million pesos, of which just 192 million pesos were approved by Enargas and qualified for a $K$ factor. Because Enargas was still evaluating many projects at the time of the final tariff determination, it retained the power to approve further projects up to ninety days after this date.

The $K$ factor is broken down by project and semester. It is activated only when an investment project has been completed according to its original specification and it meets the objectives for which it was proposed. The $K$ factor for each project is estimated as the percentage increase in tariffs that would be required so that the value of the firm is the same with and without the project.

Tariff increases for system expansion apply only to customers who benefit from the investment. Consequently, $K$ factors are specific to each

**TABLE 3**

**FINAL EFFICIENCY ($X$) FACTORS FOR TRANSPORT AND DISTRIBUTION FIRMS**

<table>
<thead>
<tr>
<th>Firm</th>
<th>$X$ factor</th>
</tr>
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<tbody>
<tr>
<td>Transportadora de Gas del Sur</td>
<td>6.5</td>
</tr>
<tr>
<td>Transportadora de Gas del Norte</td>
<td>5.2</td>
</tr>
<tr>
<td>Distribution de Gas Cuyana</td>
<td>4.8</td>
</tr>
<tr>
<td>Gas Natural BAN</td>
<td>4.8</td>
</tr>
</tbody>
</table>
Litoral Gas 4.7
Metrogas 4.7
Distribuidora de Gas del Centro 4.7
Camuzzi Gas del Sur 4.6
Camuzzi Gas Pampeana 4.5
GASNOR 4.4

*Note:* For transport firms the $X$ factors apply to all interruptible supply and firm supply tariffs. For distribution firms the $X$ factors affect residential, general small, general, compressed natural gas, and subdistribution tariffs.


### TABLE 4
**INVESTMENT (K) FACTORS APPROVED FOR GAS DEL NORTE, 1998–2002**

<table>
<thead>
<tr>
<th></th>
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<tbody>
<tr>
<td></td>
<td>First</td>
<td>Second</td>
<td>First</td>
<td>Second</td>
<td>First</td>
</tr>
<tr>
<td>Salta</td>
<td>0</td>
<td>0.84</td>
<td>0.52</td>
<td>0.74</td>
<td>0.46</td>
</tr>
<tr>
<td>Tucuman</td>
<td>0</td>
<td>1.74</td>
<td>0.61</td>
<td>0.82</td>
<td>0.55</td>
</tr>
<tr>
<td>Central</td>
<td>0</td>
<td>1.85</td>
<td>0.65</td>
<td>0.87</td>
<td>0.58</td>
</tr>
<tr>
<td>Litoral</td>
<td>0</td>
<td>1.83</td>
<td>0.64</td>
<td>0.86</td>
<td>0.57</td>
</tr>
<tr>
<td>Aldea Brasilera</td>
<td>0</td>
<td>1.81</td>
<td>0.63</td>
<td>0.85</td>
<td>0.57</td>
</tr>
<tr>
<td>Gran Buenos Aires</td>
<td>0</td>
<td>2.56</td>
<td>1.38</td>
<td>1.55</td>
<td>1.24</td>
</tr>
</tbody>
</table>

*Note:* These factors are for a project to reinforce gas mains in some areas with high population densities. Gas del Norte proposed two other projects that were still pending approval by Enargas at the time the new tariffs were formally announced.

TABLE 5
INVESTMENT (K) FACTORS APPROVED FOR METRO GAS, 1998–2002

Percent

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>0</td>
<td>0.57</td>
<td>0.54</td>
<td>0.51</td>
<td>0.48</td>
<td>0.45</td>
<td>0.42</td>
<td>0.37</td>
</tr>
<tr>
<td>Commercial and industrial</td>
<td>0</td>
<td>0.41</td>
<td>0.39</td>
<td>0.37</td>
<td>0.35</td>
<td>0.33</td>
<td>0.31</td>
<td>0.29</td>
</tr>
</tbody>
</table>

Note: These data are provisional K factors for two of the three projects presented by Metrogas. The factors are provisional pending the evaluation and approval of the third project.


It must be borne in mind that K factors are applied to tariffs in the semesters when the corresponding investment projects are under way. Thus the dates shown in tables 4 and 5 may not be the effective ex post dates if projects fall behind schedule.

Conclusion

The 1996–97 Enargas price review offers a sophisticated approach to the price regulation of natural monopolies. An extremely complex procedure, the review was based to the extent possible on objective information and rules. Its well-defined procedures and methodologies turned out to be very helpful in resisting pressure from lobbies and preventing regulatory capture.

The review also set important precedents for future price reviews in the Argentine gas industry, as well as subsequent utility price reviews in other countries and sectors.

A point of interest in the Enargas review is the adaptation of methods developed in the United States or Europe to overcome the lack of data in Argentina. In particular, the methodology adopted for estimating the cost of capital may be relevant to other developing countries.

Gas transport and distribution licenses require Enargas to identify projects that will lead to efficiency gains in order to set the X factors. This approach is unlikely to detect the full range of efficiency improvements that could potentially be made, and furthermore may lead to excessive micromanagement of firms by the regulator. To overcome these problems, Enargas used a more aggregate method (total factor productivity analysis) to determine companies' potential efficiency gains. The use of this methodology was contested by the industry, however.
Legal restrictions prevent domestic price indexation in Argentina. But because of the country's currency board system, domestic inflation is not expected to differ from international inflation.

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World Bank Guarantees for Oil and Gas Projects

Scott Sinclair

Private investors are considering several large−scale oil and gas production, pipeline, and crossborder pipeline projects in developing countries, including in West Africa and in the Caspian Sea region. While the World Bank and the International Monetary Fund are well known for their work in helping to create enabling environments for foreign investment in large infrastructure projects, by supporting reform in such areas as taxation and energy legislation, this Note focuses on a different role for the World Bank−encouraging private sector involvement in large−scale oil and gas projects by providing guarantees in direct support of the government contractual undertakings that may be needed to induce foreign direct investment in these projects. World Bank guarantees offer a unique type of risk mitigation that may prove to be a catalyst in raising finance for these projects.

In developing countries hydrocarbon resources have traditionally been owned and developed by the state. But as recovering these resources has become increasingly difficult and costly, governments have begun inviting foreign investors to become involved in the sector. The role offered to private sector participants varies from country to country, but in all cases the government continues to play a significant role, sometimes as a regulator, sometimes as an investor, sometimes as an offtake purchaser, and sometimes as all three.

Because of the large capital requirements for many oil and gas projects, and the growing reluctance of many oil and gas companies to use their balance sheets to fund these projects, many private sector sponsors are pursuing project financing. A successful project financing depends in large part on the strength of the contractual commitments of the various project participants, which, taken together, ensure lenders that there will be a reliable source of cash flow for repayment of the debt. Among the most important commitments are the contractual undertakings of the host government or governments.

References
Government Undertakings

The concession agreement between a government and the project entity is the document that defines the government's obligations to the project. This Note uses the term concession agreement broadly, to include production sharing agreements, transport and transit agreements, and government offtake agreements.

In a typical oil and gas concession agreement the government grants to the project entity the right to develop the project in exchange for a stream of payments or payments−in−kind. This government revenue stream may take several forms, but typically includes one or more of the following:

Fixed rents.

Royalties (based on sales).

Profit overrides (effectively reducing the upside potential to sponsors).

Taxes (income or otherwise).

In some concessions the government, or a stateowned enterprise such as the state gas company, will contract to purchase the oil or gas produced by the project. If the state enterprise contracts for a significant share of the throughput, the creditworthiness of this offtake obligation becomes key to the project's financeability.

A comprehensive concession agreement for a large oil and gas project should address the government's obligations to establish a framework

BOX 1 POSSIBLE GOVERNMENT UNDERTAKINGS IN A CONCESSION AGREEMENT

To maintain the same scheme of rents, royalties, taxes, duties, and accounting procedures.

To grant rights of way, easements, permits, and licenses without delay.

To grant import and export rights and visas.

To provide physical security of assets and personnel.

To adjust rents and royalties or make financial compensation to sponsors to maintain economic equilibrium in the event of political force majeure such as:

Civil unrest, war, terrorism, or blockade.

National or general strikes.

Expropriation and withdrawal of authorization.

Diversion or interruption of the commodity flow (including at the wellhead).

Change in relevant law.

To permit foreign currency transactions, banking, and bank accounts.
To guarantee cleanup of preexisting contamination.
To use international dispute resolution procedures.
To guarantee payments by government entities, such as Demand charges (for example, from the state enterprise fuel purchaser).
Specified damages.
Economic equilibrium (a mechanism for making compensatory payments or adjustments when there is a divergence from the economic transaction negotiated between the contractual parties).

for dealing with a variety of risks that might otherwise hinder a project financing. Such risks include political force majeure events (such as civil unrest and general strikes), currency availability and convertibility, and permitting (box 1).

What are the consequences if a government fails to meet its obligations under a concession agreement? Clearly, a simple right to terminate the concession agreement offers no real remedy to the project sponsors and no comfort to their lenders. Instead, a concession agreement needs to provide for financial compensation to the project sponsor, through a compensatory reduction of the government’s revenue stream or through contingent payment obligations.

A government’s willingness to bear such a contingent liability is in theory a function of its reward for doing it. The desirability of the project to the country will guide the government’s propensity to take risk in general. In other words, if the government views the benefits as high, it will be willing to stand for a large contingent obligation to the project. But if the government views the benefits as modest, it will be willing to stand for only modest undertakings.

Whatever the scope of government undertakings, and regardless of the methodology used to calculate adjustments or compensation, the ability of a government to meet its obligations, financial and nonfinancial, may well be the factor that determines a project’s financeability. Supplementing the government obligations with a World Bank guarantee covering part of the project debt may add the element that will make successful financing and implementation possible.

**Cross–border Complications**

Cross–border projects pose additional structuring challenges. Because some level of agreement is needed between the two governments on the desirability of the project, cross–border projects should include an intergovernmental agreement. Such an agreement would constitute an international treaty. These are typically less detailed than private sponsors might like. It is perhaps wishful thinking by project sponsors to expect that intergovernmental agreements would address with any detail financial compensation and risk allocation, although cross–border technical issues, such as facilitating continuous maintenance services on a transnational pipeline, could be included. But the existence of an agreement should provide significant comfort to project sponsors and their lenders.

The structuring of financial compensation for which a government might become liable also gets complicated in cross–border projects. In addition to reparations for costs directly caused by a breach of undertaking or a political risk event, private sponsors might ask for financial compensation to cover consequential losses, such as:
Carrying costs of an entire chain of projects (for example, debt servicing and other fixed costs, or equity return in all countries).

The inventory carrying cost of interrupted throughput throughout a pipeline.

In the complex negotiations for a cross-border project the principals will need to reach a mutually beneficial agreement on the appropriate compensation if a breach should occur. While a government might agree to a contingent liability exceeding the investment in its country, the World Bank's Articles of Agreement limit its ability to guarantee loans to the investment project that is in the member country.

**World Bank Guarantees**

A government's financial obligations that flow to commercial lenders to a project (through, say, bank loans, eurobonds, or 144A bonds), may be credit-enhanced by the World Bank using a partial risk guarantee. World Bank guarantees are "partial" in that they cover the minimum number of risks and the smallest amount of debt consistent with successful implementation of a project. In general, if project debt service is interrupted by failure of the government to make payment as required by the concession agreement, guaranteed lenders may call on the World Bank for payment (exceptions include payment failures resulting from events agreed to be commercial risks or events of natural force majeure, since the Bank does not underwrite such risks as a matter of policy). The World Bank would promptly pay undisputed amounts, a commitment that raises the credit rating of the government's payment obligation to AAA in the eyes of the project lenders. The World Bank would then demand reimbursement from the government under the terms of an indemnity agreement (World Bank guarantees are not insurance policies).

In most countries the World Bank considers its guarantees to be additional to its annual lending program. The provisions of the guarantees do not create new obligations but merely backstop the obligations that a government has already made to a project in the concession agreement. Bank regulators in most major economies have exempted loans covered by World Bank guarantees from certain provisioning requirements, lowering the cost of the loans and increasing the appetite of lenders to make them.

Figure 1
Cross-Border Sales To Market

World Bank Guarantees
Structuring

To use World Bank guarantees, two requirements have to be met: the government in whose territory the project is located must indemnify the Bank, and the government whose obligations are being supported by the guarantee must indemnify the Bank. In most project structures these two requirements would be met by the same government, but in cross-border projects the structures can be problematic. Some simple examples illustrate the issues.

Figure 1 shows a relatively simple structure in which a joint venture develops an oil or gas project in one country and delivers the product to the international border. Government A, which the project lenders perceive as a weak financial credit, enters into concession agreements with the joint venture. The project lenders agree to make a term loan to the joint venture on the condition that the World Bank guarantee that loan against the risk of government A breaching either of its concession agreements and causing an interruption in debt servicing. The downstream part of the project is creditworthy, so from the World Bank's perspective the "project" is entirely within country A, the obligations being backed are those of government A, and thus the indemnity of government A covers the Bank's requirements.

The example in figure 2 reverses the credit scenario. Government A has sufficient credit standing so that its concession agreements need no further support. But because the product is to be sold at the border to a state enterprise in country B that lacks independent creditworthiness, government B will have to guarantee the payment obligations of the state enterprise. The project lenders, perceiving government B as a weak financial credit, agree to make a term loan to the project on the condition that the World Bank back the guarantee obligations of government B. Again, in the World Bank's view the "project" is entirely in country A. To meet the Bank's requirements, both government A (in whose territory the project is located) and government B (whose obligations are being backed) will have to indemnify the Bank for the amount of the loan. Depending on the economic benefits accruing to country A, the requirement for an indemnity from government A could prove to be difficult to arrange without some clever structuring.
Figure 3 shows a simple cross-border joint venture where a single joint venture holds the concessions for a production facility and pipeline in country A and for a pipeline in country B. Both governments are perceived as weak financial credits by the project lenders, which will lend to the joint venture only if the World Bank guarantees the governments' payment obligations. The Bank views the initiative as two "projects" divided by the international border. To maintain transparency, the Bank prefers that the project lenders provide two separate loans, with the proceeds of each loan to be used exclusively for expenditures in one country. The Bank's indemnity requirements can easily be met in this structure, with government A indemnifying the Bank for claims under guarantee A (which covers loan A for the "project" in country A), and government B doing the same for the "project" in its country.

Figure 4 merely pulls the pieces together in what is perhaps a more likely scenario. In this example the functions are split among separate joint ventures, each constituting a "project" from the Bank's perspective. (There are often business reasons for separate joint ventures, such as to accommodate local ownership and local financing.) The Bank considers joint operations agreements between these joint ventures (including cross-default provisions in loan agreements) as commercial risks outside the scope of its guarantees. If each guarantee backs a term loan for expenditures only in the country of the "project," each government's exposure under its indemnity to the World Bank is limited to the amount invested in its territory and the Bank's indemnity requirements are clearly met.

The variations on the theme are endless. These four examples are meant only to illustrate the possibilities for using World Bank guarantees.

The Process

For the World Bank the process of issuing a guarantee begins with requests to the Bank from a host government and the private sponsors to provide a partial risk guarantee to the project lenders. World Bank procedures require approval of each guarantee by its board of executive directors. Each project must meet the Bank's standard technical, environmental, economic, and financial criteria and be in a country that is reforming to the Bank's satisfaction. The Bank must determine that the project is in the best interest of the country and that allocating guarantee coverage to the project is in the Bank's and the country's best interest. At its discretion, the Bank may
incorporate in its own appraisal the results of technical, financial, and other assessments undertaken by advisers to the project lenders.

For an oil or gas project World Bank policy generally requires public disclosure of an environmental assessment in final and agreed form at least sixty days before board approval of the project. Preparation of the environmental assessment is chiefly the responsibility of the sponsors.

The sponsors are also responsible for arranging their own financing. With the permission of the appropriate central bank, loans guaranteed by the World Bank can be in any freely convertible currency or the local currency of the country in which the project is located.

**Conclusion**

In the financial structuring of oil and gas projects World Bank guarantees can complement loans from the International Finance Corporation and the Bank and insurance from the Multilateral Investment Guarantee Agency. Guaranteed debt is often arranged at lower costs and longer maturities than would otherwise be possible; the passthrough of these savings to the government can be an important part of the Bank’s value added in a project. But the World Bank’s presence in a project reaches beyond the guaranteed debt, often bringing comfort to other parties not directly benefiting from the guarantee.

1 For more information see *The World Bank Guarantee: Catalyst for Private Capital Flows* or the *Guarantees Handbook*, available from the Project Finance and Guarantees Department, 202 473 1650.

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Mitigating Currency Convertibility Risks in High-Risk Countries
A New IDA Lending Approach

Karen Rasmussen

A proposed Currency Convertibility Fund, backstopped by a contingent credit from the International Development Association (IDA)–the World Bank's concessionary window for the world's poorest countries–has been designed for the Songo Songo Gas Development and Power Generation Project in Tanzania. The fund is a transitional mechanism aimed at supporting the Tanzanian government's efforts to attract foreign equity in circumstances where the private sector perceives a high level of risk and is otherwise unwilling to invest. The Songo Songo power project has suffered delays since 1997 arising from a dispute between the government and the Malaysian sponsors of another private power project. Now that this dispute is being resolved, preparation of the proposed Songo Songo project has resumed. The World Bank's support for the Currency Convertibility Fund is not due to go before the Bank's board for approval until 2000. Still, the fund may be a replicable mechanism that, by mitigating sovereign risks that investors are unwilling to bear and unable to hedge against, could help catalyze foreign equity investment in other IDA countries and in projects that generate local currency.

This Note examines how the International Development Association's lending instruments can be tailored to support foreign equity investment in projects that generate only local currency and for which currency convertibility insurance is not commercially available.

The government of Tanzania solicited private sector interest in a project involving the construction of a gas processing plant on Songo Songo Island and of a 220-kilometer gas pipeline. The project also includes the privatization and conversion to gas firing of a 110megawatt generating plant owned by Tanesco, the public electricity utility. The government saw significant advantages in a public–private partnership–with a direct stake in the project, equity investors should have a strong incentive to operate the facility efficiently, and Tanzania has no expertise in gas–fired electricity generation and so could benefit from private sector technical and managerial expertise.

The project would establish Songas, a majority privately owned and managed gas and electricity utility. The project would be structured as a buildown–operate arrangement, underpinned by a power purchase agreement between Tanesco and Songas. Project costs are estimated at about US$280 million (table 1). Equity investors would provide about US$72 million, and the government would contribute about US$8 million. The remaining US$200 million would be provided to the government through a credit from IDA and a loan from the European Investment Bank, both of which would be on–lent to Songas on commercial terms. In addition, IDA would provide a contingent credit of US$35 million that would provide limited protection to the project sponsors against the risk of currency inconvertibility.

The Currency Problem

Private involvement in the project ran into two main impediments: the unavailability of currency...
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*Source: International Development Association.*

Mitigating Currency Convertibility Risks in High–Risk Countries  A New IDA Lending Approach

For these reasons, the government preferred to seek private equity in the project rather than commercial debt. But while foreign equity investors were willing to assume the construction and commercial risks associated with the project, they were not willing to take on sovereign risks against which they could not hedge. Specifically, foreign investors wanted assurances that, on project sustainability grounds, they could reasonably expect to cover the project's operations and maintenance expenditures payable in foreign exchange, and repatriate their earnings in a convertible currency.1

The conclusions of a World Bank study and discussions with international oil and gas companies and political insurance agencies confirmed that foreign equity investment for the project would not materialize unless IDA or other donors were willing to address the project's currency convertibility risk. The project's foreign exchange needs would be high relative to the size of the foreign exchange market. The project would require the equivalent of 8 percent of the annual volume of foreign exchange transacted in the market.

The World Bank Group examined the instruments it had available to encourage equity investment. At the time the Bank's pilot program for partial risk guarantees to private lenders in IDA countries was not available to help raise commercial debt. Moreover, the Multilateral Investment Guarantee Agency (MIGA) was unwilling to offer currency convertibility coverage on its own account because of the high perceived risk of the project. So, to
maximize mobilization of private equity in the proposed project, the Bank designed a new financial mechanism, the Currency Convertibility Fund (CCF), to mitigate the risk of currency inconvertibility.

**What is the Currency Convertibility Fund, and How Does it Work?**

The CCF is a financial instrument, to be backed by a contingent IDA credit of US$35 million, that would provide the project sponsors with limited protection (up to US$35 million) against currency inconvertibility for operations and maintenance expenditures, dividends, and capital redemptions payable in foreign exchange.

The CCF will mitigate but not eliminate the risk to Songas of currency inconvertibility. Songas's annual foreign exchange requirements for operations and maintenance, dividends, and capital redemptions are estimated at about US$25 million, or US$500 million over the twenty–year term of the power purchase agreement. The coverage provided by the CCF would help ensure the financial viability of the project in the event of a tem–

porary lack of foreign exchange in the market. The CCF is equivalent to about sixteen months of the project's foreign exchange requirements.

The CCF would disburse only as needed to pay valid claims submitted by the project sponsors and substantiated by MIGA, which will administer the fund on behalf of the government (figure 1). The government would issue to MIGA an irrevocable right to make withdrawals from the fund to pay eligible claims. The IDA credit (and contract of guarantee) for the CCF would have a term of fifteen years (or thirteen years of commercial operations under the twenty–year power purchase agreement). This period is considered reasonable because it reflects the time required for investors to generate adequate cash flows at the agreed tariff level, and because it will help ensure that Songas remains a going private sector concern over the long term.

The CCF is structured to discourage both the government and the project sponsors from causing a claim to be filed. For the sponsors these disincentives include an extended transfer delay period before which a claim can be filed, a less than 100 percent claim coverage ratio, and an annual stop loss. Government deterrents include mandatory use of any foreign exchange recovered by MIGA in connection with a claim to prepay the CCF credit to IDA, and IDA's option of accelerating the credit if a call is made on the CCF.

In addition to the proposed development credit agreement between the government and IDA for investment in the Songo Songo Gas Development and Power Generation Project, the CCF would involve three legal agreements:

*The development credit agreement between the government and IDA for the credit to fund the CCF. The proposed IDA credit of US$35*
million to the government of Tanzania to fund the CCF would be provided under a separate development credit agreement because the CCF would involve terms and conditions that differ significantly from those that would govern the proposed IDA credit to the government for the investment project. For example, this agreement would contain conditions of disbursement related to the submission of documentation from MIGA substantiating that a valid claim had been filed for which payment was to be made. It would also confirm the government's assignment to MIGA of an irrevocable right to withdraw funds from the CCF credit on the occurrence of the defined events. Thus the CCF would disburse only if MIGA were to determine that the project sponsors had filed a valid claim substantiating their inability to convert or transfer operations and maintenance expenditures payable in foreign exchange, dividends, or capital redemptions in accordance with the provisions of the contract of guarantee (see below).

The administration agreement between the government and MIGA relating to the CCF. This agreement would spell out the relationship between the government and MIGA with respect to the management and administration of the CCF and the responsibilities of each party, including the procedures for paying eligible claims, recovering claims, and distributing premiums.

The contract of guarantee between the project sponsors and MIGA spelling out the insurance coverage to be provided by the government and issued by MIGA. The contingent IDA credit of US$35 million to be made to the government of Tanzania would provide the financial backing for MIGA to issue currency convertibility risk coverage to the sponsors up to the same amount. Thus this document would spell out the specific terms and conditions of the CCF contract of guarantee, including the items covered, the terms of coverage, and the premiums to be charged annually to the sponsors and the procedures to be followed by the sponsors before filing a claim.

Catalytic Role

IDA's involvement in the project is seen as crucial to catalyze foreign private investment by alleviating equity investors' concern about noncommercial risks. This involvement is consistent with the Bank's policies to assist sector reform by involving the private sector and to assist government borrowers in attracting this private capital by alleviating investors' and lenders' concern about sovereign risk. The contingent IDA credit of US$35 million has a leveraging effect, mobilizing US$50 million of private equity and US$22 million in other foreign equity that
would otherwise not have materialized.

1 Investors were also concerned about the risk of nonpayment by Tanesco. This risk has been mitigated through a government-funded revolving liquidity facility designed to ensure complete and timely capacity and energy payments by Tanesco to Songas, and by an escrow account that would protect the project sponsors against the loss of their equity investment in the event of an incurable government default.

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