VIET NAM: ROADMAP FOR NATURAL GAS MARKET DEVELOPMENT

Selection No. 1211198

GAS MARKET ROADMAP REPORT

Final

Prepared by: Intelligent Energy Systems (IES) & Energy Market Consulting associates (EMCa)

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Executive Summary

Project Objectives

Viet Nam has a long-standing energy policy orientation that emphasises the crucial role of natural gas in providing reliable, competitive electricity. However, despite the considerable achievements recorded by the gas sector to-date, the sector will need to become more efficient, more competitive, and more transparent if it is to serve the longer-term interests of Viet Nam which include ensuring energy security and addressing the issue of climate change. The Office of the Deputy Prime Minister has recognized this and instructed the Ministry of Industry and Trade (MOIT) to develop a roadmap for the gradual liberalization of the gas sector. MOIT in turn has requested assistance from the World Bank in developing the roadmap.

The report that follows was prepared by Intelligent Energy Systems Pty Ltd (IES) in association with Energy Market Consulting associates (EMCa), who were engaged by the World Bank to develop the detailed recommendations that make up the roadmap.

The recommended Gas Market Roadmap sets out a sequence of gas sector reform measures covering the legal framework, planning process, institutional structure, gas market mechanisms, and infrastructure development. The pace of the proposed reforms is designed to be evolutionary and conservative, avoiding a "big bang" industry restructuring that could present insurmountable implementation challenges given Viet Nam's current policy and institutional setting. The reform roadmap was also designed to be compatible with the on-going reform program in the electricity sector.

Motivations for Gas Market Liberalisation

Viet Nam's gas sector has recorded an impressive track record over the 30 years since the first oil and gas was produced in the Bach Ho field. Gas production currently stands at approximately 1 billion cubic feet per day and reserves are the third largest in Southeast Asia, after Indonesia and Malaysia. Viet Nam Oil and Gas Group (PVN) is a major driver of economic activity and contributes 20-35 percent of the state's budget revenues.

However, threats to the long-term viability of the gas sector have emerged and have provided the impetus for policy-makers to consider fundamental changes in the legal, regulatory and institutional arrangements governing the sector.

- Existing gas fields are depleting and new supplies have been slow to come on stream. Moreover, new domestic gas fields (such as Block B and Cai Voi Xanh) will be more expensive to develop and operate than existing fields.
- PVN's activities have expanded well beyond those of the core business of gas and oil which has diluted their focus and raised concerns over whether they are serving the best interests of Viet Nam as a whole.
- PVN's balance sheet has become stretched and its ability to fund the needed investment to increase domestic production has become limited.

- Viet Nam has found it extremely difficult to attract investors into new Production Sharing Contracts (PSC's) because of highly-regulated domestic gas prices, high field development costs, and industry-wide capital constraints resulting from low global oil and gas prices.
- Based on the current production outlook, Viet Nam will begin importing significant volumes of LNG within the next 5-10 years and will be subject to world market pricing for this component of its overall supply portfolio.

Proposed Gas Market Roadmap

The proposed Gas Market Roadmap sets out a detailed agenda of sector reforms that address the challenges described above and move Viet Nam's gas sector toward higher levels of efficiency, competitiveness and transparency. The reform measures—described in detail in Section 12 of the report—are grouped into three categories:

- **Legal and Regulatory Framework**: promulgation of the Prime Minster decisions, MOIT circulars, codes of practice, charters and regulations needed to facilitate the transition to a liberalized market;
- **Organisational Structure**: establishing the necessary governance entities and restructuring PVN's business functions in order to establish regulatory transparency and minimize conflicts of interest; and
- **Gas Market Mechanisms**: development over time of gas contracting arrangements and pricing mechanisms that enable gas buyers and gas sellers to engage in trade such that a progressively higher portion of Viet Nam's gas supply is traded at market prices.

The reforms in each category are partitioned into four time periods covering the period up to 2020 and the five-year periods 2021-2025, 2026-2030, and 2031-2035. The evolution of reforms is also mapped against the likely timing of new gas supply and infrastructure projects The Gas Market Roadmap is summarised in Figure 1.

Period to 2020

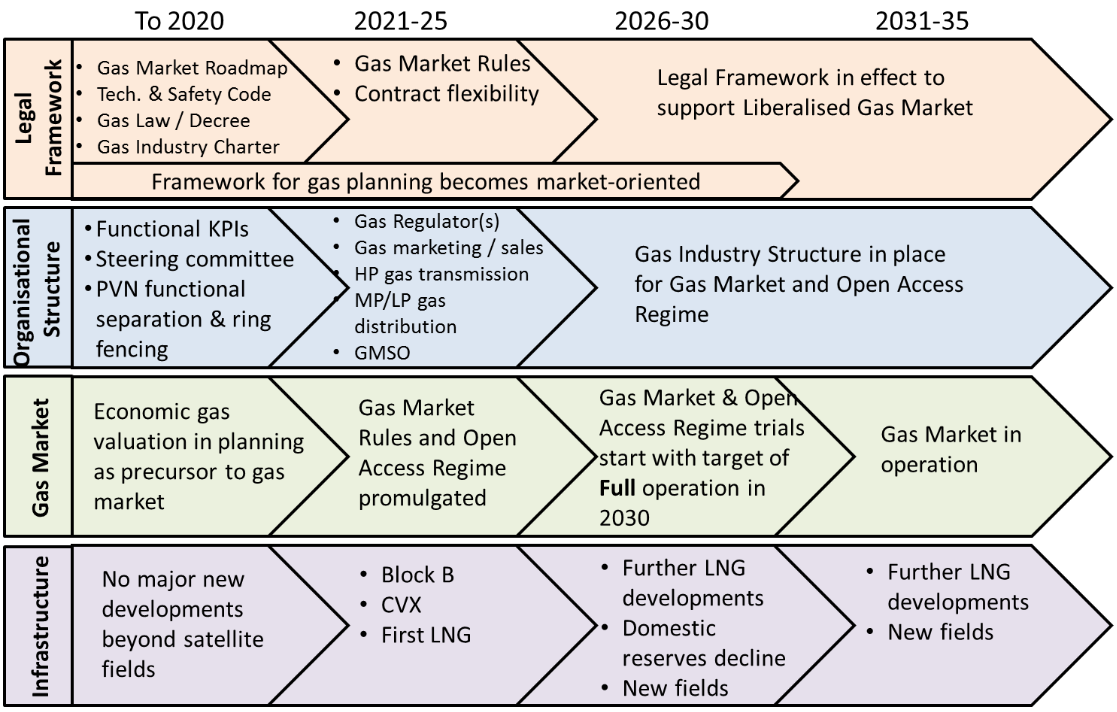
The initial phase of the Gas Market Roadmap focuses on establishing the necessary legal and regulatory framework to support a competitive wholesale gas market and taking the first steps towards organisational and institutional restructuring. Key proposed steps through to the year 2020 are:

- Finalisation and promulgation of the Gas Market Roadmap as a Prime Minister Decision;
- Development and promulgation of a Gas Law as a Government Decree defining the regulated and non-regulated (competitive) elements of the gas sector, licensing requirements, access regimes, pricing principles, and other fundamental arrangements;
- Development and promulgation of a Gas Industry Charter defining the responsibilities of the key entities within the gas sector;
- Formation of a Gas Market Steering Committee (GMSC) under MOIT with the authority and mandate to progress the Gas Market Roadmap and monitor outcomes;
- Initiation of PVN restructuring by: *i)* ring-fencing of midstream gas businesses, *ii)* separating non-oil and gas business from the core business structure with a view to

ultimate divestment of those businesses, and *iii)* definition of a set of key performance indicators for PVN's core businesses;

- Issuance of industry-wide Technical & Safety Codes based on international standards and separation of technical and safety regulation functions from PVN; and
- Improvements in the gas sector planning process incorporating an economic valuation methodology based on transparent guidelines and data sources and a consistent method for incorporating the effects of emissions, fiscal impacts, energy security, and balance of payment issues.

Figure 1 Proposed Gas Market Roadmap



Period from 2021 to 2025

During the period 2021-2025, the broad objective is to complete the changes to Viet Nam's legal and regulatory framework necessary to support a competitive wholesale gas market and to complete the restructuring of PVN. Key steps in this period include:

- Development and promulgation (in the form of a Circular) of Gas Market rules allowing flexibility in gas supply contracting and removing regulations inhibiting gas trading;
- Implementation of an open access regime for gas pipeline connection and transportation;
- Establishment (based on the Gas Law) of an independent gas economic, technical and safety regulator—this could be a "GRAV" with an analogous scope and mandate to that of ERAV in the electricity industry;

- Establishment of an independent organization under MOIT with responsibility for gas sector planning;
- Continuation of PVN restructuring to include: *i)* separating midstream and downstream gas business functions, particularly PVGas from the upstream oil and gas business, and *ii)* transfer of the gas management and system operations functions to an independent Gas System and Market Operator (GSMO); and
- Further enhancements to the gas planning process to: *i)* use economic cost-benefit evaluations and least cost planning to determine investment priorities and *ii)* enhance integration between the gas sector and the electric and industrial sectors.

Period from 2026 to 2030

With all of the preconditions for a competitive wholesale gas market in place by 2026, the primary objective of the next five-year period is to go through the process of piloting the gas market and commencing its full operation. Key actions in this period include:

- The GMSO commences pilot operation of the gas market based on established open access arrangements, new gas contracts, and modified legacy gas contracts;
- Investments are made in the ICT systems and infrastructure necessary to support gas market operations;
- The GMSC conducts a review of the pilot gas market including and assessment of the effectiveness of the newly-created entities in taking on their assigned responsibilities;
- GRAV monitors and reports on the outcomes of the pilot including compliance with gas market rules;
- Depending on government policies and financial considerations, the midstream and downstream businesses of PVN could be considered for divestment;
- Incremental changes to the Gas Market Rules and Technical Codes, as required based on experience during the pilot; and
- Further market-oriented revisions to the Gas Master Planning framework.

Period from 2031 to 2035

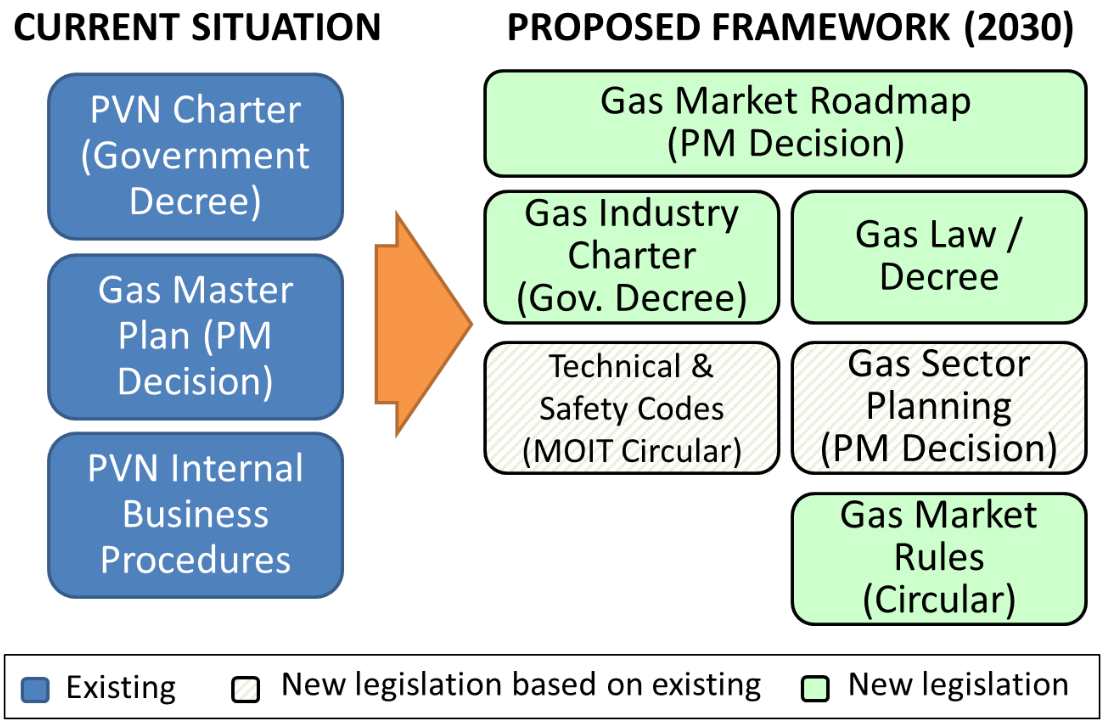
With the pilot gas market complete, the focus of the period 2031-2035 will be on reviewing and refining the gas market in order to ensure that it delivers efficient outcomes for Viet Nam's energy industry. Key activities during this period could include:

- The GMSC could lead a final investigation into the progress of the Gas Market Roadmap and, depending on the outcome, it could thereafter be decommissioned;
- To capture efficiency gains, consolidation of the electricity SMO and the gas GSMO could be considered;
- The feasibility of a retail gas market could be evaluated; and
- Refinements or improvements to the legal and regulatory framework would be assessed.

Required Legal and Regulatory Framework for Viet Nam's Gas Market

The proposed Gas Market Roadmap depends on fundamental changes to Viet Nam's existing legal and regulatory framework. Figure 2 summarises the current legislation and the revised legal framework required to support a competitive wholesale gas market.

Figure 2 Required Legal and Regulatory Framework



Major Challenges

International experience suggests that a gas sector reform agenda as ambitious as the one presented in this Gas Market Roadmap will take a long time and will encounter setbacks and challenges. Some of the most challenging issues can be expected to emerge in the following areas:

- The current direction from government to retain the status quo to 2025 sets a precedent for no action until after 2025. However, given the urgency of developments in Viet Nam's gas sector and the fact that there are numerous no regrets improvements that be introduced immediately, this pace is likely to be far too slow.
- Restructuring PVN, a wholly government owned entity that has its monopoly status for all oil and gas activities in Viet Nam written into the law in its Charter. Experience suggests that changes are likely to be resisted.
- Change in culture away from a centrally planned and managed gas industry towards one built around unbundled regulated midstream monopolies and merchant gas supply entities.

- Ensuring developments in the electricity sector and gas sector are coordinated. The Gas Market Roadmap and Electricity Industry Reforms Roadmap have some dependencies – particularly in relation to allowing prices to gradually become cost reflective as Viet Nam's electricity industry becomes increasingly linked to global energy prices.
- Transition away from pricing and supply approaches that provide some industries with preferential treatment, for example, the petrochemical industry.
- Introducing flexibility in existing contracts. The roadmap presented here assumes that buyers and sellers will seek to mutually agree to changes that would introduce flexibility in the contracts, but there is the risk that this could not deliver a desirable outcome.
- Introducing a framework for economic valuation of natural gas and the shift away from a focus on legacy, project-specific gas pricing levels.
- Ensuring that MOIT is sufficiently well-resourced with staff capable of progressing and oversighting the implementation of the Gas Market Roadmap.

Immediate Priorities

To gain momentum in implementing the Gas Market Roadmap, the immediate priorities to 2020 are as follows:

- Promulgate the Gas Market Roadmap as a PM Decision;
- Develop a legal framework to create certainty to the industry and potential investors. This involves:
  - setting up industry-wide Technical, Safety and Environmental Code(s);
  - promulgating the Gas Law as a Government Decree;
  - promulgating the Gas Industry Charter as a Government Decree superseding the PVN Charter;
- Make immediate progress in relation to separating PVN's business units and ring-fencing them as a major precondition for commencing a fair and competitive gas market; and
- Introduce an enhanced and standardised economic valuation of natural gas framework to improve the quality of decision-making.

Table of Contents

Executive Summary iii

Project Objectives iii

Motivations for Gas Market Liberalisation iii

Proposed Gas Market Roadmap iv

Period from 2031 to 2035 vi

Required Legal and Regulatory Framework for Viet Nam's Gas Market vii

Major Challenges vii

Immediate Priorities viii

1 Introduction 19

1.1 Project Objectives 19

1.2 Summary of Approach to the Study 19

1.3 Summary of Key Documents Reviewed 20

1.4 Report Purpose 21

1.5 Report Structure 22

PART A: GAS MARKET LIBERALISATION AND ROLE OF THE GAS MARKET ROADMAP 24

2 Gas Market Liberalisation in Viet Nam 25

2.1 Motivation for Gas Market Liberalisation 25

2.2 Gas Master Plan (GMP) Directives for Gas Market Development 26

3 Proposed Gas Market Roadmap 30

3.1 Role of Gas Market Roadmap 30

3.2 Comments on Government's Directives 30

3.3 Proposed Gas Market Roadmap 30

PART B: CURRENT STATE AND DEVELOPMENT OPTIONS FOR VIET NAM'S GAS INDUSTRY 33

4 Gas Industry Outcomes to Date 34

4.1 Historical Gas Supply and Demand 36

4.2 Implications for Gas Market Development 38

5 Gas Industry Development Options 40

5.1 Domestic Gas Reserves 40

5.2 LNG Imports 42

5.3 Other Development Options 45

5.4 Implications for Gas Market Development 45

5.5 Transitional Steps 46

PART C: GOVERNANCE AND INDUSTRY STRUCTURE 47

6 Governance and Institutional Arrangements 48

6.1 Current Governance and Institutional Structure 48

6.2 Key entities that govern Viet Nam's gas industry 49

6.3 Governance and Institutional Challenges to Market Development in Viet Nam 51

6.4 Steps towards Functional Separation in the Gas Supply Chain 53

6.5 Future Governance and Institutional Arrangements 60

6.6 Summary and Transitional Steps 63

7 PVN's Role in the Gas Market 65

7.1 PVN Scope and Organisation Structure 65

7.2 Current Role of PVN 65
7.3 PVN Role in a Liberalised Gas Market 66
7.4 Barriers to Market Development – PVN Organisation 67
7.5 Transitional Steps 68
7.6 Summary and Transitional Steps 73
PART D: ECONOMICS, PRICING AND PLANNING 75
8 Economic Valuation of Gas 76
8.1 The Role for Economic Valuation of Natural Gas in Viet Nam 76
8.2 Economic Valuation of Gas 76
8.3 Economic Value of Gas: A Case Study Assessment 80
8.4 Implementation of Economic Assessment of Gas Value 83
8.5 The application of economic valuation of gas in Viet Nam now and its future role in a liberalised market 85
8.6 Summary and Transitional Steps 86
9 Pricing and Contractual Mechanisms 89
9.1 Current Gas Pricing Approach in Viet Nam 89
9.2 Alternative Pricing Approaches 91
9.3 Current Regulatory and Contractual Constraints 92
9.4 Issues to be addressed for Gas Market Development 95
9.5 Summary and Transitional Steps 97
10 Gas Industry Planning 99
10.1 Gas Master Plan 99
10.2 Revised Power Development Plan 105
10.3 Critique of the Draft GMP 107
10.4 Suggested Improvements to Gas Planning Framework 109
10.5 Summary and Transitional Steps 111
PART E: LEGAL AND REGULATORY FRAMEWORK TO SUPPORT VIET NAM'S GAS MARKET 114
11 Required Legal and Regulatory Framework to Support a Gas Market in Viet Nam 115
11.1 Required Legal and Regulatory Framework 115
11.2 Gas Market Roadmap (Prime Minister Decision) 116
11.3 Gas Supply Industry (GSI) Charter (Government Decree) 116
11.4 Gas Law (Government Decree) 117
11.5 Gas Market Rules (Circular) 117
11.6 Gas Sector Planning and Economic Valuation Framework 118
11.7 Technical, Safety and Environmental Protection Codes 118
11.8 Summary and Transitional Steps 119
PART F: VIET NAM'S GAS MARKET ROADMAP 121
12 Proposed Gas Market Roadmap for Viet Nam 122
12.1 Approach to Gas Market Roadmap 122
12.2 Proposed Gas Market Roadmap 123
12.3 Period from 2031 to 2035 131
12.4 Gas Market Roadmap Tabulated Matrix 132
12.5 Synchronisation with Electricity Sector 139
12.6 Challenges and Priorities 140
Appendix A Key Gas Infrastructure 142
Appendix B GMP Development Options – Further Details 144

B.1 Further Details on Domestic Fields 144
B.2 LNG Imports 145
B.3 Downstream Gas Market under GMP 145
B.4 Key Offshore Gas Pipeline Developments 146
B.5 Gas Collecting and Inter-Field Pipeline Developments 149
B.6 Key Onshore Gas Pipeline Developments 150
B.7 Low Pressure Gas Pipelines 150
B.8 Gas Processing Plants (GPPs) 150
B.9 LNG Import and Regasification Terminal 151
Appendix C Economic Costing: Case Study and Assessment 152
C.1 Application of the valuation methodology to current technology and fuel costs 152
C.2 Base Case Model 152
C.3 Sensitivity to Capacity Factor 153
C.4 Model Comparison 154
C.5 Comparison of well head and LNG supplied estimates 154
C.6 Potential Model Considerations and Adjustments to Economic Gas Net-back Valuation 155
Appendix D Case Studies: Implementation Risks for Gas Sector Reforms 156
D.1 Institutional change relating to the gas sector in national energy planning 156
D.2 Gas Market Design 156
D.3 Pricing Principles for Gas 157
D.4 Changed roles for the NOC (PVN) in the Gas Sector 158
D.5 Failure to Implement the Road Map 159
Appendix E Case Studies: Gas Pricing Mechanisms in Selected Asian Countries 160
E.1 China Gas Price Approach 160
E.2 Japan Gas Price Approach 167
E.3 Malaysia Gas Price Framework 170
E.4 Thailand Gas Price Framework 174
Appendix F Case Study: Western Australia Gas Market Development 178
F.1 Background 178
F.2 Early Market Developments 178
F.3 Industry Re-organisation 179
F.4 Contractual Re-organisation 179
F.5 Second Phase Industry Re-organisation 180
F.6 Second Phase Regulatory Development 181
F.7 Second Phase Market Development 181
F.8 Third Phase Regulatory Developments 182
F.9 Third Phase Market Developments 182
F.10 Introducing Broad Specification Gas 183
F.11 Conclusion 184
Appendix G Case Study: Viet Nam Electricity Reforms Roadmap and its Implementation 185
G.1 Background to Electricity Industry Reforms Roadmap 185
G.2 2006 Electricity Industry Reforms Roadmap 187
G.3 2006 Electricity Reforms Roadmap Implementation 188
G.4 2013 Electricity Industry Reforms Roadmap 194
G.5 2013 Electricity Reforms Roadmap Implementation 196
G.6 Implications of Electricity Industry Reforms for Gas Market Roadmap 199

List of Figures

Figure 1 Proposed Gas Market Roadmap v
Figure 2 Required Legal and Regulatory Framework vii
Figure 3 Illustration of Project Tasks 20
Figure 4 GMP Directives for Gas Market Development 27
Figure 5 Proposed Gas Market Roadmap 32
Figure 6 Offshore Gas Fields 35
Figure 7 Viet Nam's Gas Regions 35
Figure 8 Historical Gas Supply from Each Basin, 2006-16 36
Figure 9 Historical Gas Demand by Region, 2006-16 37
Figure 10 Gas Demand Composition by End Use, 2006-16 38
Figure 11 Viet Nam's Gas Reserves 40
Figure 12 Gas Reserves Plausible for Production in 2015-35 41
Figure 13 Locations of Planned LNG Developments (PVN) 44
Figure 14 Major Gas Pipeline Projects in the Southern Regions 45
Figure 15 Transitional Steps for PVN's Role in the Gas Market 46
Figure 16 Current governance structure of Viet Nam's petroleum and power supply industry 48
Figure 17 Step A: Separation and ring-fencing of PVN existing key market functions 54
Figure 18 Step B: Unbundling gas pipeline transmission and distribution providing non-discriminatory access regime for gas transportation and connection. 56
Figure 19 Step C: Establish a balancing and secondary trading market building on the existing balancing market to optimise & trade gas entitlements 57
Figure 20 Step D: Permit other parties to develop new transmission and distribution pipelines and offer transportation (shipping) services 59
Figure 21 Step E: Competitive purchase of domestic gas and LNG – multiple buyers 60
Figure 22 Governance and Institutional Structure for unbundling market functions of the existing PVN organisation 62
Figure 23 Transitional Steps for Governance and Institutional Structure 64
Figure 24 Indicative Functional Structure of PVN at Step 1 69
Figure 25 Functional Structure of PVN including other functions at Step 2 70
Figure 26 Functional Structure of PVN at Step 3 71
Figure 27 Functional Structure of PVN and the Viet Nam gas sector at Step 4 72
Figure 28 Transitional Steps for PVN's Role in the Gas Market 74
Figure 29 Gas Demand and Supply 76
Figure 30 Net back value methodology for the gas fired generation based on imported coal – net back value at the gas fired power station 78
Figure 31 Representation of net economic value of gas delivered in electricity network 78

Figure 32 Net back value methodology for the gas fired generation based on imported coal - net back value at the well head 79
Figure 33 Net back value methodology for the gas fired generation based on imported coal - net back value for industrial and commercial sectors 79
Figure 34 Net back value methodology for the gas fired generation based on imported coal - net back value for LNG 80
Figure 35 Base Case 85% CF - Total Electricity Cost for Coal and Gas Scenarios 81
Figure 36 Total Electricity Costs for Coal and Gas at Different Capacity Factors 81
Figure 37 Sensitivity of Economic Value of Gas at 85% capacity factor 82
Figure 38 Sensitivity of Economic Value of Gas at 60% capacity factor 83
Figure 39 Net back value methodology for gas fired generation based on imported coal – new wellhead resource unconnected to competitive hub 86
Figure 40 Transitional Steps for Economic Valuation of Gas 88
Figure 41 Spot vs Contract LNG Prices (USD) for Delivery into Tokyo Bay 91
Figure 42 Contracting Arrangement 1 93
Figure 43 Contracting Arrangement 2 94
Figure 44 Contracting Arrangement 3 94
Figure 45 Transitional Steps for Pricing and Contractual Mechanisms 98
Figure 46 Sequence of Developments Proposed in GMP 100
Figure 47 P1 + P2 Gas Supply Projection for Viet Nam's Domestic Reserves under the GMP 101
Figure 48 P1+P2+50%.P3+P4+P5+POS Supply Projection for Viet Nam's Domestic Reserves under the GMP 101
Figure 49 Downstream Gas Market Development under the GMP 102
Figure 50 Gas Production and Demand Forecast including LNG Demand based on Draft GMP Information 103
Figure 51 LNG Demand Forecast under the Draft GMP 104
Figure 52 LNG Terminal Sizes (Left: Size by Terminal Site, Right: Size by Region) 104
Figure 53 Installed Capacity (MW) of Gas Project Developments in RPDP7 106
Figure 54 Transitional Steps for Gas Industry Planning 113
Figure 55 Required Legal and Regulatory Framework 116
Figure 56 Transitional Steps for Legal and Regulatory Framework 120
Figure 57 Proposed Gas Market Roadmap 124
Figure 58 Electricity Industry Reform Roadmap (2013) 139
Figure 59 Base Case - Total Electricity Cost for Coal and Gas Scenarios 153
Figure 60 Total Electricity Costs for Coal and Gas at Different Capacity Factors 153
Figure 61 Base Case comparison to Lantau 2014 published analysis 154
Figure 62 Implied Gas well head and LNG delivered price for Base Gas, Base LNG, Lantau 2014 155
Figure 63 Heating Value vs. Shadow Pricing $/MMbtu (illustrative purposes only) 155
Figure 64 Traditional pricing regime for domestic gas, China 161
Figure 65 Thailand's Natural Gas Supply, 1990-2011 175

Figure 66	Australian Gas Industry Map	184
Figure 67	2006 Electricity Market Roadmap	188
Figure 68	Structure of Viet Nam’s Electricity Industry under the VCGM	190
Figure 69	Generation Capacity by Ownership (MW as at 2015)	191
Figure 70	VCGM Cost-Based Pool Market Structure	193
Figure 71	Electricity Industry Reform Roadmap (2013)	195
Figure 72	Outline of VWEM Trading Arrangements	198

List of Tables

Table 1	Regional Supply and Demand Balance for 2016, mmscm	38
Table 2	Summary of Planned New Gas Fields (Domestic Fields)	42
Table 3	Proposed LNG Import Terminals	43
Table 4	Summary of GMP Development Sequence	100
Table 5	Summary of Gas Demand and Projected Sector Growth	102
Table 6	Gas Market Roadmap Table	133
Table 7	Summary of Key Gas Infrastructure in Viet Nam	142
Table 8	Summary of Proposed Main Gas Pipelines	147
Table 9	Proposed Gas Processing Plants	150
Table 10	Base Case Input Assumptions	152
Table 11	Malaysia Wholesale Gas Pricing	171
Table 12	Malaysia End User Gas Pricing	171

Glossary

CCGT	Combined Cycle Gas Turbine
CF	Capacity Factor
EIA	Environmental Impact Assessment
EMCa	Energy Market Consulting associates
ERAV	Electricity Regulatory Authority of Viet Nam
EVN	Electricity of Viet Nam
FO	Fuel Oil
FOB	Free on Board
FSRU	Floating Storage and Regasification Unit
GDC	Gas Distribution Centre
GDE	General Directorate of Energy
GDP	Gross Domestic Product
GDSP	Gas Distribution Service Provider
GHG	Greenhouse Gas
GMP	Gas Master Plan
GMSC	Gas Market Steering Committee
GRAV	(Proposed) Gas Regulatory Authority of Viet Nam
GSA	Gas Supply Agreement
GSB	Gas Single Buyer
GSI	Gas Supply Industry
GSMO	(Proposed) Gas System and Market Operator
GSPA	Gas Sales and Purchase Agreement
GTSP	Gas Transmission Service Provider
HP	High Pressure
HR	Human Resource
HSE	Health, Safety and Environment
ICT	Information Communication Technology
IES	Intelligent Energy Systems
JV	Joint Venture
JVA	Joint Venture Agreement
KPI	Key Performance Indicator
LNG	Liquefied Natural Gas
LP	Low Pressure
LPG	Liquefied Petroleum Gas
MOE and NR	Ministry of Environment and Natural Resources
MOIT	Ministry of Industry and Trade of the Socialist Republic of Viet Nam
MP	Medium Pressure
NLDC	National Load Dispatch Centre

NOC	National Oil Company
O&M	Operations and Maintenance
P1	Proved Reserves considered to have a 90% certainty of being produced
P2	Probable Reserves considered to have a 50% certainty of being produced
P3	Possible Reserves considered to have a 10% certainty of being produced
P4	Contingent petroleum resources which are not commercially recoverable
P5	Contingent petroleum resources which are not commercially or technically recoverable
PM	Prime Minister
POS	Undiscovered petroleum-initially-in-place
PSC	Production Sharing Contract
PVGas	PetroVietnam Gas Corporation
PV Power	PetroVietnam Power Corporation
PVEP	PetroVietnam Exploration Production Corporation
PVN	Viet Nam Oil and Gas Group, trading as Petrovietnam
RPDP7	Revised Power Development Plan No 7
SMO	System and Market Operator (in Viet Nam's electricity industry)
SWOT	Strengths, Weaknesses, Opportunities, and Threats
TOR	Terms of Reference
VCGM	Viet Nam Competitive Generation Market
VREM	Viet Nam Retail Electricity Market
VWEM	Viet Nam Wholesale Electricity Market
WB	The World Bank Group

1 Introduction

1.1 Project Objectives

Intelligent Energy Systems Pty Ltd (IES) in association with Energy Market Consulting associates (EMCa) have been engaged by the World Bank Group (WB) to undertake a consultancy entitled, "Viet Nam: Roadmap for Natural Gas Market Development".

The objective of the project is to assist Ministry of Industry Trade (MOIT) in formulating a Roadmap to gradually liberalise Viet Nam's gas sector. Specifically, the following areas should be advised on:

- Economic costing of natural gas;
- Options for evolution of market-based pricing of natural gas, and the options for natural gas market development post-2020;
- Synchronisation of emerging liberalized gas market with competitive power market and with the long-term gas contract market;
- Development options for supporting infrastructure; and
- Natural gas regulatory mechanism, including specific approaches to price formation and regulation.

This consultancy was financed by the WB.

1.2 Summary of Approach to the Study

The approach that we have proposed to take to address the TOR's scope of work is illustrated in Figure 3, and is based on the completion of the following tasks:

- Task 1: Inception phase;
- Task 2: Establish assessment criteria;
- Task 3: Perform the following assessments:
  - Assessment of the current situation: physical and institutional;
  - Development scenarios for Viet Nam's gas and electricity sectors;
  - Issues and options for governance and institutional arrangements;
  - Issues and options for pricing mechanisms and gas market designs;
  - Issues and options for synchronisation with electricity industry reforms;
  - Issues and options for transitioning the gas sector over say a 15 to 20-year period, in a way that would be consistent with the Electricity Industry Reform roadmap;
  - Economic valuation of gas for a number for scenarios;
  - Review international experience for gas sector liberalisation approaches;
- Task 4: Issues and options paper;
  - Options considered for the following:
    - Transition stages;

- Organisational structures;
- Pricing mechanisms;

– Assess the options against assessment criteria (conduct SWOT analysis);

– Assess the options against different scenarios for gas infrastructure development;

– Make some preliminary recommendations based on assessment;

- Task 5: Workshop No. 1 on Issues and Options;
- Task 6: Draft Report:
  - Refine and adjust findings based on feedback from Task 4;
  - Conduct a more detailed assessment of the recommended approach;
  - Provide recommendations on roles of PVN and other agencies (EVN, ERAV etc.);
  - Provide a more detailed roadmap for gas sector reforms and its synchronisation with electricity industry reform roadmap;
- Task 7: Workshop No. 2 on Draft Report; and
- Task 8: Final Report.

Figure 3 Illustration of Project Tasks

Task 1: Inception	• Focus on understanding the key issues in Hanoi • Confirm developments in gas and electricity sectors
Task 2: Criteria	• Objectives of reform, constraints, importance of certain issues • Formulate criteria to later evaluate the roadmap options (SWOT)
Task 3: Assessments	• Current situation & planned developments, economic valuation of gas, institutional arrangements
Task 4: Issues & Options	• Set out feasible options for: governance, institutional, pricing mechanisms, gas market designs, development stages…
Task 5: Workshop No. 1	• Present the findings on issues and options to stakeholders • Gain feedback on preliminary recommendations
Task 6: Draft Report	• Draft roadmap taking into account Tasks 2-5
Task 7: Workshop No. 2	• Presentation on the draft roadmap • Gain feedback on preliminary recommendations
Task 8: Final Report	• Updated draft taking into account feedback and issues raised on Task 6 and 7

1.3 Summary of Key Documents Reviewed

The following documentation has been reviewed:

- PVN Charter;
- Prime Minister Directive No. 296/TB-VPCP dated 27 July 2014;

- Draft Gas Master Plan (GMP);
- PM Decision No. 60/QD-TTg dated 16 January 2017 approving the Plan for Development of the Viet Nam Gas Industry by 2025 with Vision to 2035 (GMP);
- PM Decision No 168/QD-TTg dated 7 February 2017 approving the Proposal for Restructuring of the Electricity Industry for the Period 2016-2020 with Outlook toward 2025;
- MOIT Decision 8266/QD-BCT dated 10 August 2015 approving the Detailed Design of the Wholesale Electricity Market of Viet Nam (VWEM);
- PM Decision No. 63/2013/QD-TTg Road Map, Conditions and Power Sector Organization Structure for Viet Nam Power Market Stages Formation and Development;
- PM Decision No.: 28/2014/QD-TTg Regulations on Structure of Electricity Retail Tariff;
- PM Decision No. 2068/QD-TTg Approving the Development Strategy of Renewable Energy of Viet Nam by 2030 with a Vision to 2050;
- MOIT Decisions 3023/QD-BCT, 3024/QD-BCT and 3025/QD-BCT dated 1 June 2012 establishing EVN Genco 1, EVN Genco 2 and EVN Genco 3;
- Revised Power Development Master Plan 7 (RPDP7);
- Procedure of Gas Allocation for Day Ahead Scheduling;
- Previous consultant's reports:
  - ESMAP Study: "Viet Nam Gas Sector Development Framework – Final Report", January 2010
  - ECA, "Task 1 Report – Pricing Options and Lessons from Other Markets in Asia", April 2013
- Viet Nam Energy Sector Assessment, Strategy and Road Map, December 2015, Asian Development Bank;
- Viet Nam Natural Gas Profile, February 2011, EnergyQuest;
- Various reports of PVN;
- Various conference presentations on the Viet Nam energy sector;
- Various proprietary studies on Viet Nam's gas sector;
- Various news and magazine articles and opinion pieces on the Viet Nam energy sector; and
- A number of economic models developed to assist with the assessment of various energy options for Viet Nam.

1.4 Report Purpose

The previous report entitled "Issues and Options" was focused on presenting assessments of different aspects of Viet Nam's gas sector. The assessments covered Viet Nam's current gas sector situation and plans, infrastructure development options for Viet Nam, governance and institutional arrangements, PVN Role in the Gas Market, Pricing mechanisms and gas market development approaches and the economic value of natural gas. The report concluded with a number of options that could be explored to transition Viet Nam towards one where the gas market is liberalised.

This report refines the assessments of options considered for gas market development based on comments and feedback from two industry stakeholder workshops. This has been used to propose transitional steps for each issue which in turn forms the basis of a gas market reforms roadmap. The gas market roadmap is essentially a strategic document for use by the Government of Viet Nam to undergo a transition from the existing arrangements towards arrangements that can support a liberalised gas market.

1.5 Report Structure

The report has been structured around several parts in order to logically work its way through the issues leading up to the final recommendation, which is the Gas Market Roadmap. In particular:

- Part A: Gas Market Liberalisation and Role of the Gas Market Roadmap:
  - The purpose of part is to set out the reasons for Viet Nam undertaking a path of gas market liberalisation and sets out the role of the Gas Market Roadmap.
  - Section 2 provides a discussion of the motivation behind Viet Nam considering the development of a gas market and the Government's directive towards establishing a Gas Market.
  - Section 3 then sets out purpose and role that the Gas Market Roadmap should have before presenting the report's main recommendation – which is the Roadmap itself.
  - The remainder of the report provides detailed justifications and considerations that form the basis of the presented Roadmap.
- Part B: Current State and Development Options for Viet Nam's Gas Industry:
  - This part briefly summarises historical outcomes of Viet Nam's gas industry and sets out the key infrastructure development options that have been identified by the Government.
  - Section 4 provides a summary of historical outcomes to date for Viet Nam's gas industry; and
  - Section 5 sets out gas industry infrastructure development options.
  - Both sections provide a commentary on the implications for gas market development and recommends that key developments be included as part of Roadmap to ensure coordination between infrastructure development and an ongoing transition towards a Gas Market.
- Part C: Governance and Industry Structure:
  - This part comments on how the wider governance arrangements for Viet Nam's gas industry need to be transitioned in order accommodate a gas market before considering the issue of restructuring PVN's business to accommodate a level playing field, thereby encouraging greater participation in Viet Nam's gas industry.
  - Section 6 assesses the existing governance and institutional arrangements before setting out a suitable transition path for Viet Nam;

- Section 7 discusses the role of PVN within the gas market;

- Part D: Economics, Pricing and Planning:
  - Section 8 provides a discussion on the economic valuation of natural gas which could be adopted as way of making decisions more efficient in the near-term until a fully open gas market is put into operation.
  - Section 9 provides an assessment of the current gas pricing approach in Viet Nam before setting out gas market design approaches that could be considered by Viet Nam; and
  - Section 10 provides an assessment of gas sector planning in Viet Nam and sets out improvements that could be made and transitional steps for moving from the existing arrangements towards arrangements that would be compatible with a gas market.
- Part E: Legal and Regulatory Framework to Support a Gas Market in Viet Nam:
  - Section 11 sets out the key legal and regulatory documents that would need to be established as part of the transition towards a liberalised gas industry.
- Part F: Proposed Gas Market Roadmap for Viet Nam:
  - Section 12 set out the final recommendations of the report which is a detailed discussion of the proposed Gas Market Roadmap for Viet Nam.
  - This part also identifies the key immediate term challenges that need to be addressed for the Gas Market Roadmap to be successful and provides some brief comments on the synchronisation of the Gas Market Roadmap with the Electricity Industry Reforms Roadmap.

The following appendices are also included:

- Appendix A provides a summary of key gas pipeline infrastructure in Viet Nam for reference;
- Appendix B summarises further details from the Gas Master Plan (GMP) in relation to development options for Viet Nam's gas sector;
- Appendix C provides some case studies relevant to the economic valuation of natural gas;
- Appendix D sets out a discussion of gas market implementation risks based on numerous international experiences;
- Appendix E provides case studies in relation to gas pricing mechanisms as implemented in a selected number of Asian countries;
- Appendix F sets out a detailed discussion of the development of a gas market in Western Australia; and
- Appendix G provides a detailed discussion of Viet Nam's electricity industry reforms experience, which we consider extremely important and which we draw upon in the formulation of the Gas Market Roadmap.

PART A: GAS MARKET LIBERALISATION AND ROLE OF THE GAS MARKET ROADMAP

2 Gas Market Liberalisation in Viet Nam

2.1 Motivation for Gas Market Liberalisation

Viet Nam's oil and gas industry has historically been a priority area of development because oil and gas production for the purpose of stimulating economic development and in terms of making a significant contribution to the country's fiscal balance[1]. After 30 years of oil and gas development, Viet Nam is ranked about 28th among 52 countries in relation to gas and oil potential in the world, and is ranked 3rd in South East Asia in terms of proven gas reserves, after Indonesia and Malaysia[2].

Established in 1977, Viet Nam Oil and Gas Group (PVN) has become a major contributor of Viet Nam's economy, contributing some 20% to 25% of the state's budget revenues. Wholly owned by the government, PVN is responsible for all oil and gas resources in the country with core activities including all operations from oil and gas exploration and production to storage, processing, transportation, distribution and services. PVN's business activities have developed rapidly since its establishment and especially since first oil production in Bach Ho field in 1986.

While Viet Nam and PVN in particular have had great success over the last 40 years, there remain numerous challenges to the gas industry that are prompting change and in particular, the liberalisation of Viet Nam's gas sector.

The reasons that are prompting such thinking are:

- The existing gas fields that are in production are becoming depleted. New supplies have been slow to come on stream with commercial, pricing, market, and regulatory issues cited as barriers to their development.
- New domestic gas fields will be more expensive to develop and operate compared to existing fields. PVN's ability to develop these fields is more difficult compared to the past which has created a greater need for encouraging participation of new developers and operators as investors.
- Having PVN as the national gas sector champion has proven to be appropriate in the early years of development of Viet Nam's oil and gas sector, by helping to offset risks, providing a means of exploring and developing new fields. However, now there are different challenges facing Viet Nam which prompts the need for reforms. PVN's activities have expanded well beyond those of the core business of gas and oil which has diluted their focus raising concerns over whether they are serving the best interests of Viet Nam as a whole, including its consumers and industries that use gas.
- PVN's balance sheet has become stretched and its ability to fund the needed investment to increase domestic production is limited. Therefore, additional sources of investment funds are needed and the role of PVN along the whole gas supply chain needs to be reviewed to ensure that it is not hampering gas sector development and inhibiting the

[1] M. R. Tsibulnikova, V. A. Pham, T. Yu Aikina, "Outlook for the Development of Oil and Gas Industry in Viet Nam", IOP Conf. Series: Earth and Environmental Science 43 (2016) 012094.

[2] Le Viet Trung, Tran Quoc Viet, Pham Van Chat, "An Overview of Viet Nam's Oil and Gas Industry", Petroleum & Economics Management, Vol. 10, 2016, Viet Nam Petroleum Institute, available: www.vpi.pvn.vn.

growth of gas usage in industries that have a higher economic valuation of gas and usage of gas.

- While historically Viet Nam has been able to attract Joint Venture (JV) partners and enter into Production Sharing Contracts (PSCs), over the last 10 years' progress has become far more limited. The high investment costs of new fields are occurring in a gas pricing environment that is not cost reflective and based on pricing that was appropriate for earlier (and less costly) gas developments. Viet Nam's low price environment combined with tighter global constraints on capital increases the importance of putting in place a stable and transparent gas regulatory and pricing framework. This is a necessary condition in order to attract investors and operators and secure financing for large infrastructure projects.
- Large and capital intensive LNG facilities are under consideration in Viet Nam. This further highlights the importance of having transparent and stable policies in place to attract investors and secure financing for large projects. It also places a higher importance on ensuring that efficient investment decisions are made in terms of LNG options. LNG technology has advanced considerably in the recent past and thus it is important that development options be carefully evaluated. Decisions need to be made in Viet Nam in relation to the location of LNG facilities, the use of Floating Storage and Regasification Units (FSRUs) compared to onshore receiving facilities, and with regard to the trade-offs between short-term LNG contracts (which can be more flexible) compared to long-term LNG contracts. A market oriented framework for the gas industry will enable the trade-offs between risks and rewards to be assessed and ought to lead to more efficient decisions, to Viet Nam's benefit.
- Gas investments and gas allocation to end users has to date not been based on sound economic principles. This distorts pricing and inhibits future investments. As part of the transition towards a gas market, standardisation of economic cost-benefit analysis and the use of least cost economic planning should further encourage efficient investments.
- There is a potential "gas supply crunch" coming, with many of Viet Nam's gas users thinking past gas prices can continue into the future. It is critical that Viet Nam avoids a gas crisis and a related power supply crisis, by transitioning to a more economically rational approach to pricing gas and creating the environment where new gas can be delivered to meet growing demand in a timely, orderly and efficient manner.
- Viet Nam's national energy security could be enhanced by improving the way that gas is developed, transported, stored and traded – this again highlights the importance of having a consistent, transparent, and well-structured legal, contractual, market, and regulatory arrangements for the gas sector.

2.2 Gas Master Plan (GMP) Directives for Gas Market Development

Against the background of the motivations for gas market liberalisation, directives of The Prime Minister's Decision No. 60/QD-TTg dated 16 January 2017, on approving the Plan for Development of the Viet Nam Gas Industry by 2025 with Vision to 2035 ("GMP") has also identified the need for change in Viet Nam's gas sector. The reason is that the directive canvasses a range of issues that are directly relevant to the gas market roadmap and it is important to ensure that the gas market roadmap is complementary and aligned with the broader direction of the GMP legislation.

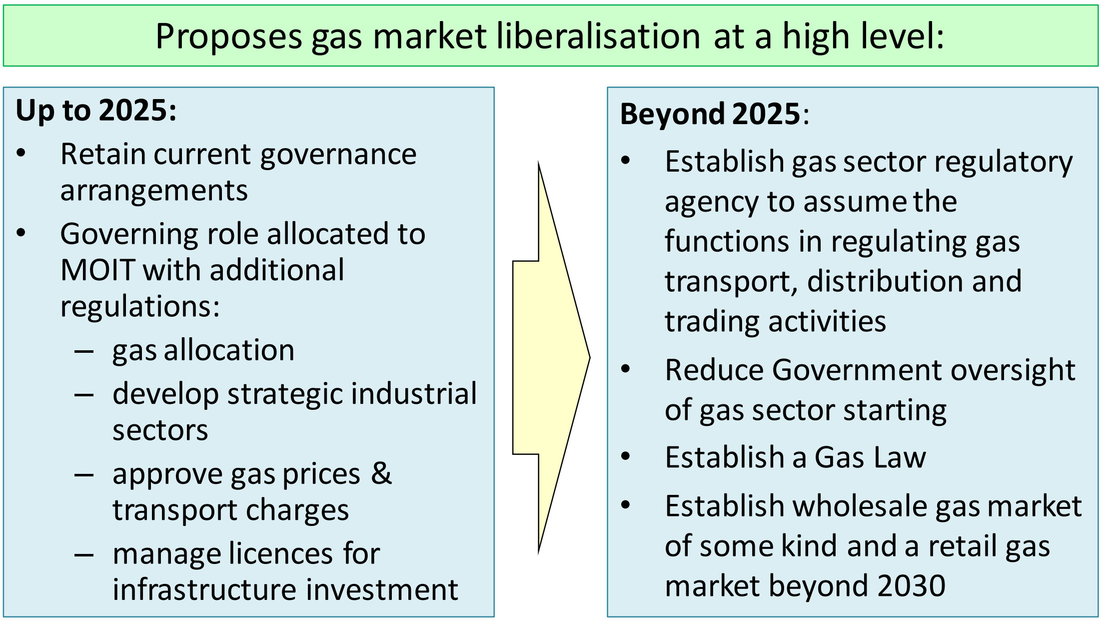
The GMP suggests a strategy for gas market development, with the key periods being from present to 2025 and the period beyond 2025. This is shown in Figure 4.

Specific directions that this legislation sets for gas market development as follows:

- Complete the transition of the gas sector management model towards the free market direction in the post-2020 period;
- Gradually progress to a management model where the Government only administers the gas industry operation through legislative documents and market participants are granted autonomy to negotiate their commercial agreements involving gas sale, purchase, transportation and trade;
- Enhance, update the legislative documents related to the gas sector management commensurate with current conditions of the domestic gas industry and international conventions; and
- Establish rational gas market price policies with assurance that interests of the Government, businesses and consumers are all duly respected.

The draft detailed contents of the GMP which were available to the Consultant have also recommended on the development path for the Viet Nam gas market.

Figure 4 GMP Directives for Gas Market Development



2.2.1 Prior to 2025

The GMP directives for market reform prior to 2025, are firstly to retain the current governance arrangements of the gas sector, with the Government continuing to regulate the market operations via PVN and PVGas. Secondly, the Government has assigned the governing role in the sector to the MOIT. To strengthen sector governance and management, the MOIT then needs to be availed with additional regulatory legislation, including:

- Regulations for gas allocation to major industrial sectors to safeguard the industries from disadvantages associated with gas market liberalisation such as sudden price spikes or reduction in gas supply. Concurrently, this arrangement is also consistent with the Government's target to encourage development of strategic industrial sectors.
- Approve (but not set) the levels for gas prices and gas transportation tariffs. Through approving these price and fee levels, the Government realises their leading role in regulation and management of the gas market.
- Issue licences for infrastructure investment activities and monitor the safety in operating the gas infrastructure.

2.2.2 Beyond 2025

Beyond 2025, the GMP directives for market reform are as follows:

- Establish a gas sector regulatory agency to assume the functions in regulating gas transport, distribution and trading activities, to gradually reduce Government's involvement in governing the gas sector, consistent with the wholesale competitive market model and retail market model (post 2030). The roles of the Government will include:
  - Reinforce the monitoring and regulatory functions over gas trading, transport and distribution activities.
  - Provide directions and guidance for parties participating in gas transactions and for resolution of the disputes arisen.
  - Provide rules as per which gas users are allowed to trade in the wholesale market and which users only in the retail market.
  - Develop / amend the Oil and Gas (Petroleum) Law.
  - Develop / amend the Competition Law.
- The amended Petroleum Law / Gas Law and legislations underneath shall set out the rules and procedures regulating gas production, trade, transport, distribution and uses, and the relationships between gas / LNG market participants. These legal documents also specify the roles and responsibilities of the state overseeing agencies (GDE and / or any independent gas regulator when applicable) in enforcing the rules and regulations set forth. The scope of these rules covers:
  - Conditions & requirements for participation in the gas market; rights and responsibilities of market participants.
  - Management of the gas infrastructure development planning: participants in the planning process and levels of involvement, contents of the planning and execution procedures.

- Regulations for infrastructure project investment and construction management; approval and issuance of investment licenses, business registrations with required technical, commercial and environmental conditions and standards.
- Rules on setting up of the monitoring / regulatory entities to oversee related activities, in particular gas transportation and distribution.
- Third party access to gas pipelines.
- Operational codes and procedures for gas pipelines and gas despatch.
- Gas metering regulations, safety and environmental protection rules.
- Regulations on gas products and services quality; gas pricing, transportations fees and other charges setting rules.
- Gas purchase and gas transportation agreements.
- Gas cost allocation and accounting regimes.
- Rules enforcement and dispute resolution.

3 Proposed Gas Market Roadmap

3.1 Role of Gas Market Roadmap

The GMP directives for gas market development set the general direction for gas market liberalisation in Viet Nam. The Gas Market Roadmap ("Roadmap") is intended as a strategic policy document that sets the scene for a gradual transition towards gas market liberalisation. The Roadmap provides a more detailed sequence of transitional steps that encompass a range of areas that are critical to gas market liberalisation. Viet Nam has previously successfully implemented Roadmaps of this nature in other industries, most notably the electricity sector. The Gas Market Roadmap structure and content has been developed to follow a similar structure and to ensure synchronisation between electricity and gas market evolution.

3.2 Comments on Government's Directives

The directives of the Government set the scene for formulating a more detailed strategy for transitioning Viet Nam's gas industry towards one that is liberalised. The directive identifies a number of important elements and features of regulations that need to be established to enable a gas market. However, there remain many challenges, including: (1) providing greater clarity and detail on the legal and regulatory framework, (2) providing more concrete governance structure for the industry, (3) setting out clear and identifiable milestones for transitioning of PVN's business towards one that is compatible with competition, and (4) identifying some immediate term changes to improve the efficiency of the gas sector.

Furthermore, the pace of reforms under the directive largely suggests retaining the status quo until 2025 before contemplating the next steps. This is not rapid enough, nor does it identify steps that could be started immediately that would prepare Viet Nam for a liberalised gas market.

The Roadmap has been formulated to address these challenges.

3.3 Proposed Gas Market Roadmap

While detailed discussion of its reasoning, content and approach is the subject of this report, we present the proposed Gas Market Roadmap upfront in Figure 5 to explain its structure, general content. The foregoing content is then able to clearly indicate the components of the Roadmap that assessments and analysis relate to.

The Roadmap has been modelled on the Electricity Industry Reforms Roadmap in Viet Nam which was originally legislated in 2006 (see Appendix D). The Gas Roadmap and Electricity Roadmap could be considered an example of integrated policy framework for the energy industry. The periods of time have been set to be broadly consistent with the 2025 breakpoint of the GMP's directives and also the developments of the GMP itself. These are:

- Up to 2020 period;
- 2021-25 period;
- 2026-30 period; and

- 2031-35 period.

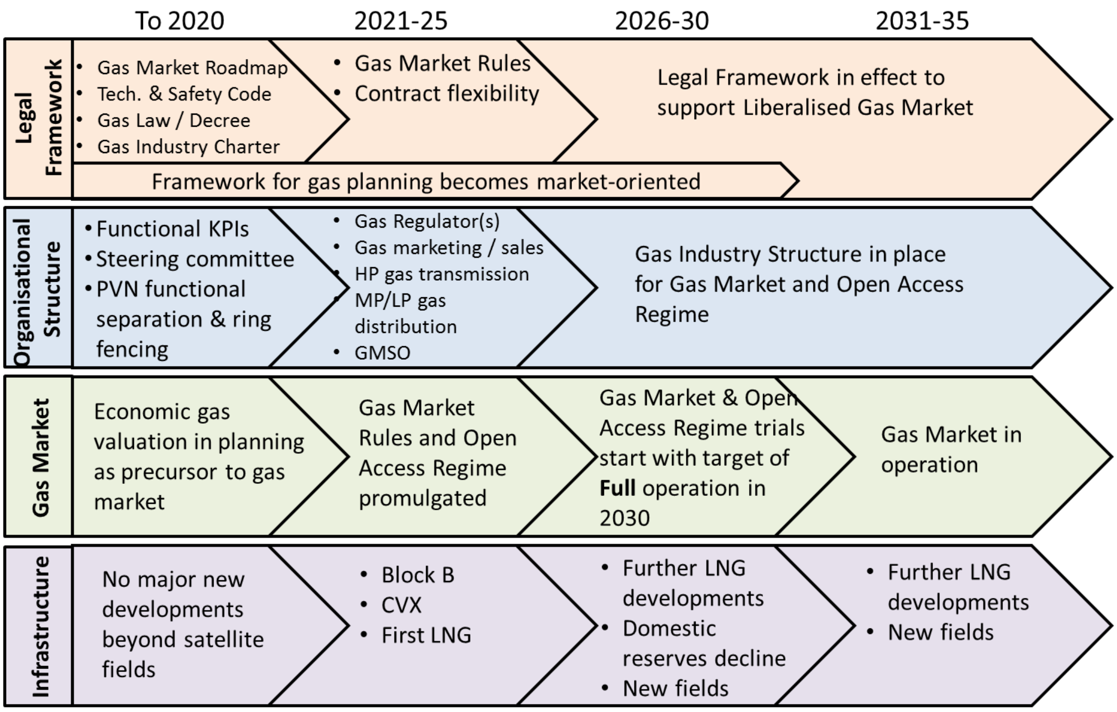
The key dimensions of areas where transitions need to be achieved (which are shown as the rows) represent the dimensions of gas market liberalisation. They draw heavily on the approach that has been adopted in the Electricity Reforms Roadmap, and are:

- Legal and Regulatory Framework:
  - Prime Minister decisions;
  - MOIT Circulars;
  - Codes of practice;
  - Charters; and
  - Regulations.
- Organisational Structure
  - Internal reorganisation;
  - Functional separation;
  - Ring-fencing requirements; and
  - Creation of new legal entities and legal separation.
- Gas Market (Trading) Mechanisms:
  - Gas contracting arrangements;
  - Mechanisms to enable buyers and sellers of natural gas to engage in trade; and
  - Pricing mechanisms.
- Supporting processes and Infrastructure:
  - Processes required to support the operation of the gas market; and
  - Planned infrastructure developments.

The legal and regulatory framework dimension largely sets out the necessary transition steps for establishing the laws and rules for Viet Nam's gas industry. The legal and regulatory framework can be established well in advance of starting a gas market and in doing so, it creates transparency and confidence to the industry participants and potential investors. Organisational structure is very much concerned with setting up the necessary governance entities and restructuring PVN's business units. Gas market developments shows the transitional steps that we suggest for developing the gas market. Finally, the infrastructure dimension is largely an outlook of infrastructure developments to ensure synchronisation between physical developments in the industry and development of a gas market.

A more comprehensive discussion of the Roadmap is given in section 12.

Figure 5 Proposed Gas Market Roadmap



PART B: CURRENT STATE AND DEVELOPMENT OPTIONS FOR VIET NAM'S GAS INDUSTRY

4 Gas Industry Outcomes to Date

Viet Nam is a coastal country with several hundred thousand square kilometres of continental shelf in which seven tertiary sedimentary basins have been identified. These are shown to the left in Figure 6. Major gas reserves have been found in four of the seven offshore basins: Song Hong, Nam Con Son, Cuu Long and Malay - Tho Chu. The total gas reserves have been reported at around 871 Bcm.

Large scale gas extraction has been carried from 1995 at oil and gas fields in Cuu Long and Nam Con Son basin, and lately in Malay - Tho Chu basin. In 2014 the total offshore gas production was approximately 9.8 Bcm, and the accumulated production was 127.64 Bcm by the end of 2014, leaving the remaining available reserves at 743 Bcm. Overall indigenous gas supply from Viet Nam in 2016 is estimated at 1,051 mmcfd[3].

In summary the status of upstream fields that are in production is as follows:

- Cuu Long, which is an oil-prone basin, delivered 55.66 Bcm or 48% of the nationwide accumulated gas production by 2014 but the production has been in decline;
- Nam Con Son, which likewise is a gas-prone basin, delivered 61.33 Bcm or 48% of the nationwide accumulated gas production by 2014 that is also in decline;
- Malay - Tho Chu, an offshore area administered jointly with Malaysia which transports natural gas to Ca Mau from Block PM3-CAA and the Cai Nuoc field, had produced 10 Bcm or 7.84% of the nationwide accumulated gas production by 2014. This basin is yet to reach its maximum production capacity; and
- Song Hong, where the gas extraction from small deposits has recently commenced but the production is expected to increase over the coming years with operations Thai Binh field (2015), Ham Rong field (2018) and Ca Voi Xanh field (2023).

Gas supply from South East Viet Nam will reduce as production from the Lan Tay field declines over the next few years. However, with the completion of the first phase of the Nam Con Son 2 pipeline, gas production from the Dai Hung and Thien Ung fields began in 2015. The second phase of the Nam Con Son 2 pipeline will also see the Sao Vang field being developed and associated gas from the Su Tu Trang field.

Figure 6 shows Viet Nam's offshore oil and natural gas basins while Figure 7 illustrates how Viet Nam can be considered to consist of four "gas regions": North, Central, South East and South West. North and Central are emerging gas regions while the South East and the South West have been supplied with offshore gas since 1995 and 2007 respectively. There is no interconnection between South East and South West. Further details of gas supply infrastructure in Viet Nam has been summarised in Appendix A.

[3] Viet Nam gas and LNG - 2016 long term regional outlook, Wood Mackenzie (2016).

Figure 6 Offshore Gas Fields

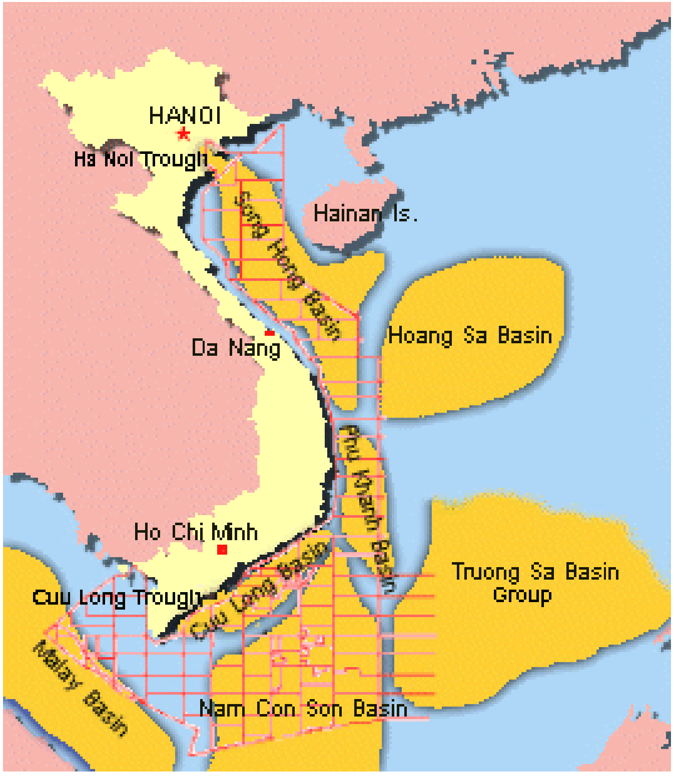
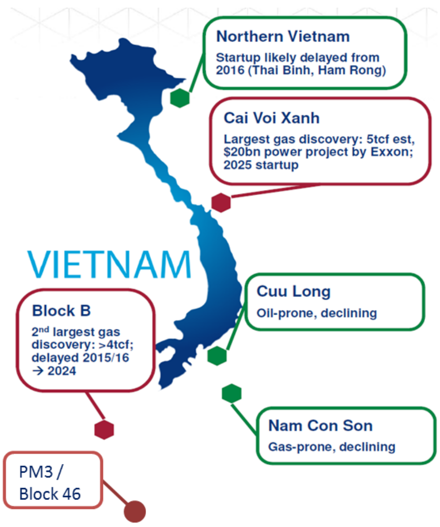


Figure 7 Viet Nam's Gas Regions

Region	Basin	Features
South East	Cuu Long Basin	• Oil prone basin in operation since 1995 ⇔ Delivered > 55.66 Bcm (44%) of nation-wide gas production. • *Production in decline*.
	Nam Con Son 1 & 2	• Gas prone basin in operation since 2003 ⇔ delivered > 61.33 Bcm (48%) of nation-wide gas production. NCS2 in operation since 2016. • *Production in decline.*
South West	Malay-Tho Chu	• Offshore area administered jointly with Malaysia. Ca Mau pipeline in operation since 2007. • Ca Mau supplied from Block PM3-CAA + Cai Nuoc field • Delivered > 10 Bcm (8%) of nation-wide gas production. *Not yet reached maximum production capacity*
North-Centre	Song Hong	• Gas extraction from small deposits has recently commenced. *Production expected to increase*. • Production expected to be increased in future with Thai Binh, Ham Rong field, Ca Voi Xanh fields



- Key regions: South East and South West, North, Centre
- No interconnection between SW and SE
- ~83% of gas for power generation most of the rest for fertilizer plants + industry

4.1 Historical Gas Supply and Demand

4.1.1 Existing gas fields

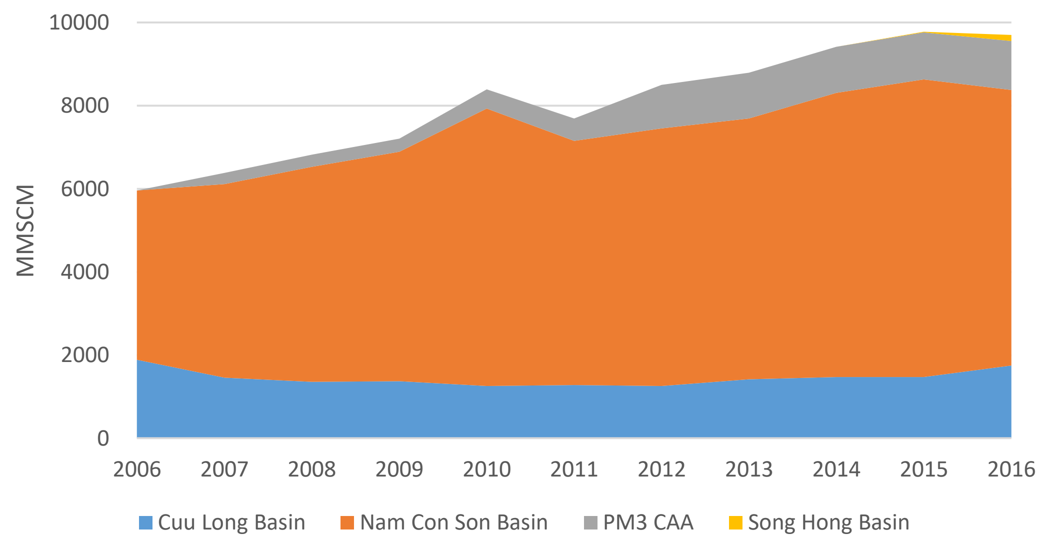
As stated earlier, large scale gas extraction has been carried oil and gas fields first in Cuu Long and Nam Con Son basins, and lately in Malay - Tho Chu basin. Gas extraction has also recently commenced from small deposits in Song Hong basin in the North-Central region. According to PVN statistics, there are 48 gas fields curently in production and 15 fields under or planned for development these four major basins. Major active fields include Bach Ho (commenced 1986) in Cuu Long basin, Lan Tay – Lan Do (2002), Rong Doi (2006), Hai Thach – Moc Tinh (2013) in Nam Con Son basin, and PM3-CAA (2007) in Malay - Tho Chu basin.

PetroVietnam holds a large stake in Viet Nam's oil and gas reserves as partner in a number of PSC contracts. Main international holders of Viet Nam commercial gas reserves include Gazprom and Rosneft (Russia), Mitsui & Co and METI (Japan), KNOC (Korea), PTTEP (Thailand) and ONGC (India).

4.1.2 Historical gas supply

Figure 8 shows historical gas supply from each basins for the period 2006 to 2016. It indicates that the total quantity delivered from the off shore fields has increased from just under 6,000 mmscm in 2006 to around to 9,500 mmscm in 2014 and plateaued out at 9,700 mmscm during 2015-2016. Nam Con Son has been the largest gas basin producing more than 73% of the total gas supplied over the given period. In combination with Cuu Long Basin, the domestic gas delivered in the South East region made up around than 90% of the total gas supply nationwide. In the South West region, after the commencement of the PM3 block, the annual supply increased to above 1,100 mmscm since 2012. Song Hong Basin in the North East region started producing some lesser amounts of gas in 2015-2016.

Figure 8 Historical Gas Supply from Each Basin, 2006-16

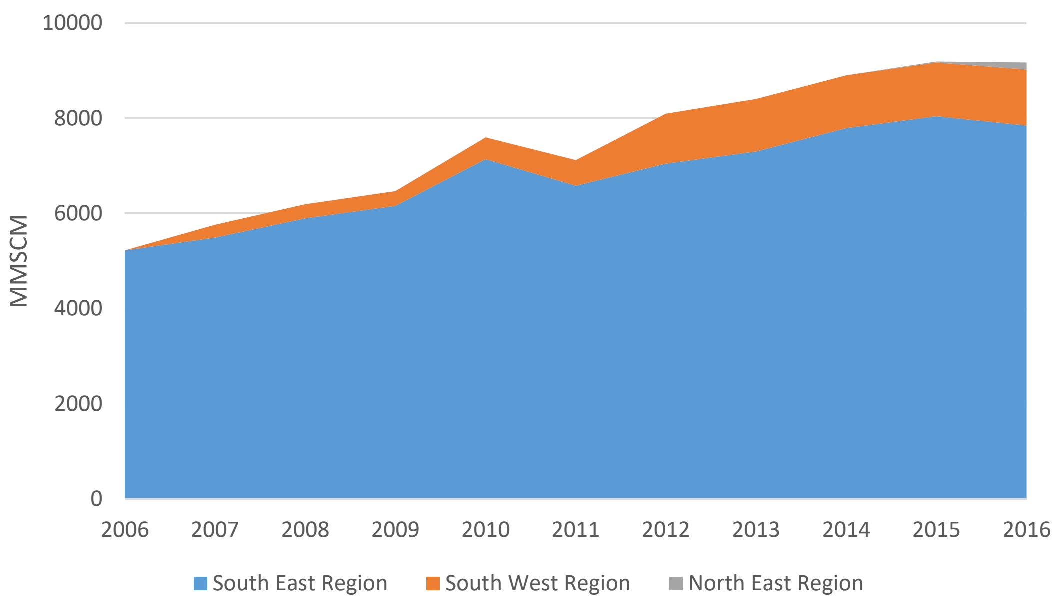


Source: Consultant based on PVN information

4.1.3 Historical gas demand

Figure 9 shows the gas demand by each region in the same 2006-2016 period. The total gas demand was 9,169 mmscm in 2016 from which 7,844 mmscm was used in the South East market and 1,181 mmscm was consumed in the South West region. It is noted that differences between gas supply and gas demand volumes were merely the amounts of gas that went to LPG and condensate production, and these applied only for the South East market since the PM3-CAA gas is technically dry and no portion of it has been used to produce liquefied gases.

Figure 9 Historical Gas Demand by Region, 2006-16



Source: Consultant based on PVN information

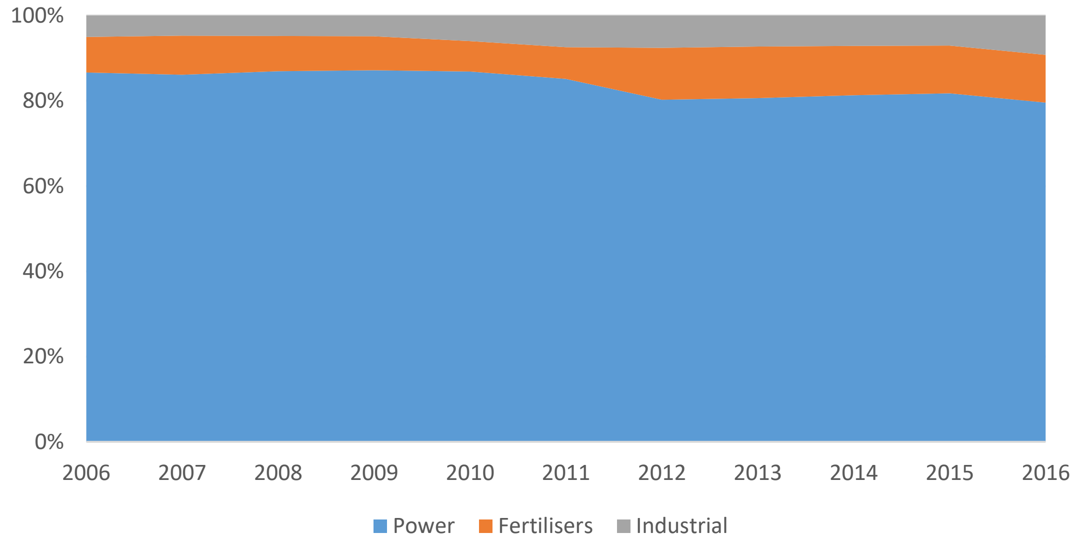
Changes in the gas demand composition by end use are illustrated in Figure 10 which shows that the power generation sector has been the main gas user accounting for more than 80% of the total gas demand over the 2006-2016 period. Gas consumption by fertilisers has been stable at 11% while the other industrial gas users (currently only present in the South East and North East regions) increased their share from 5% in 2006 to more than 9% in 2016.

Industrial gas demand in the South East mainly comes from the chemical and ceramic sectors. According to Wood Mackenzie[4], PVGas has met difficulties in finding additional industrial demand due to the sharp fall in oil prices. However, it is expected that oil prices recovery and gas being reasonably priced will encourage new industries to switch to using gas. Over the next few years, PVGas hopes to grow the gas market by attracting a new ammonia plant, ethane extraction plant and the development of the Long Son petrochemical complex that includes a polyethylene plant. PetroVietnam holds 29% ownership of this petrochemical complex development that is being led by the Siam Cement Group, Thailand.

[4] Wood Mackenzie Viet Nam gas and LNG - 2016 long term regional outlook, July 2016

In the South East region, industrial demand is unlikely to grow until PVN develops Block B&52. There is already insufficient supply to meet existing gas demand thus any plans to introduce gas distribution can only take place once more supply comes online.

Figure 10 Gas Demand Composition by End Use, 2006-16



Source: Consultant based on PVN information

4.1.4 Supply and demand snapshot 2016

Table 1 shows a snapshot of the 2016 supply and demand situation.

Table 1 Regional Supply and Demand Balance for 2016, mmscm

Region	Supply	Demand			
		Total	Power	Fertilisers	Industrial
South East	8,376[5]	7,844	6,597	548	699
South West	1,181	1,181	699	482	-
North East	144	144	-	-	144
Total	**9,701**	**9,169**	**7,296**	**1,030**	**843**

4.2 Implications for Gas Market Development

The present state of Viet Nam's gas industry has the following implications for gas market development:

- Viet Nam's gas sector currently consists of a number of isolated gas regions or markets of small scale: South East, South West and the North/Central regions.

[5] The difference between (PVGas) gas supply to shore and gas demand in the SE region was due to the amount of LPG and condensate separated from the gas produced from the oil-prone Cuu Long basin.

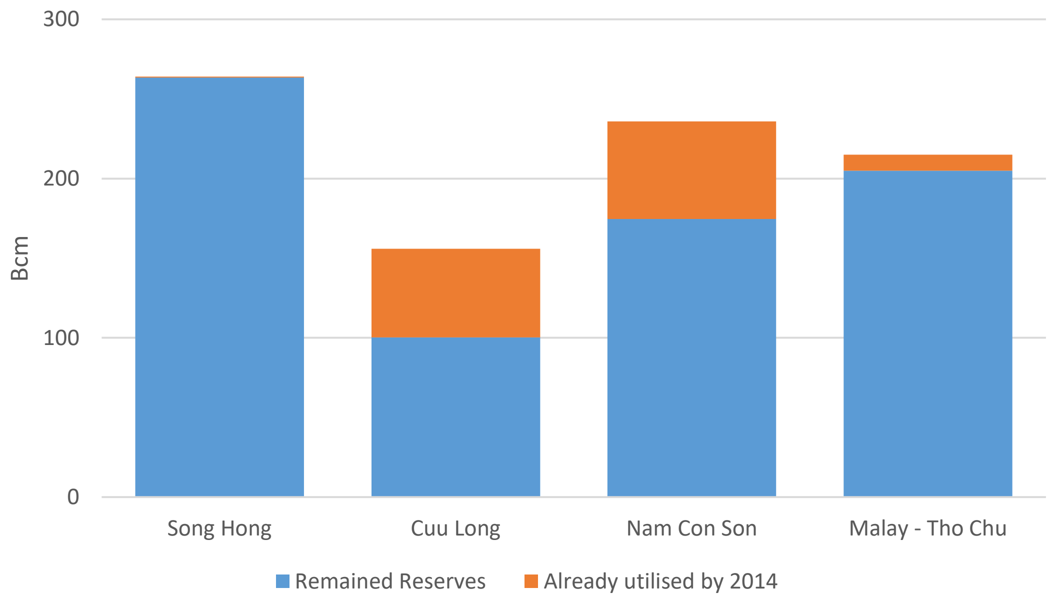
- As there is no physical interconnection between the regional gas markets, there are limits on the size of the markets and also the opportunities for existing industry participants to trade gas.
- Current gas supply situation in Viet Nam is broadly structured around having a single source of offshore gas supplying single sets or groups of users / or single user complex. This single supply point to demand is a barrier for open access to infrastructure.
- While there are no physical interconnections between the isolated regional markets it should be recognised that there is a linkage via the electricity market for power generations.
- Production from most of the existing gas fields is declining while the implementation of the LNG import plans has been slow. It is therefore imperative to ensure gas supply meets the underlining demand in the mid-term and long-term.

5 Gas Industry Development Options

5.1 Domestic Gas Reserves

Figure 11 shows the gas reserves that have been identified each of the four major gas basins: Song Hong in the North-Central region (also called North East), Cuu Long and Nam Con Son in the South East and Malay-Tho Chu in the South West. The total gas reserves have been reported at around 871 Bcm with the accumulated exploitation being at 127.64 Bcm by the end of 2014, leaving the remaining available reserves at 743 Bcm. Song Hong and Ma Lay-Tho Chu basins have the largest unutilised reserves, with more than 200 Bcm accounted for each region.

Figure 11 Viet Nam's Gas Reserves

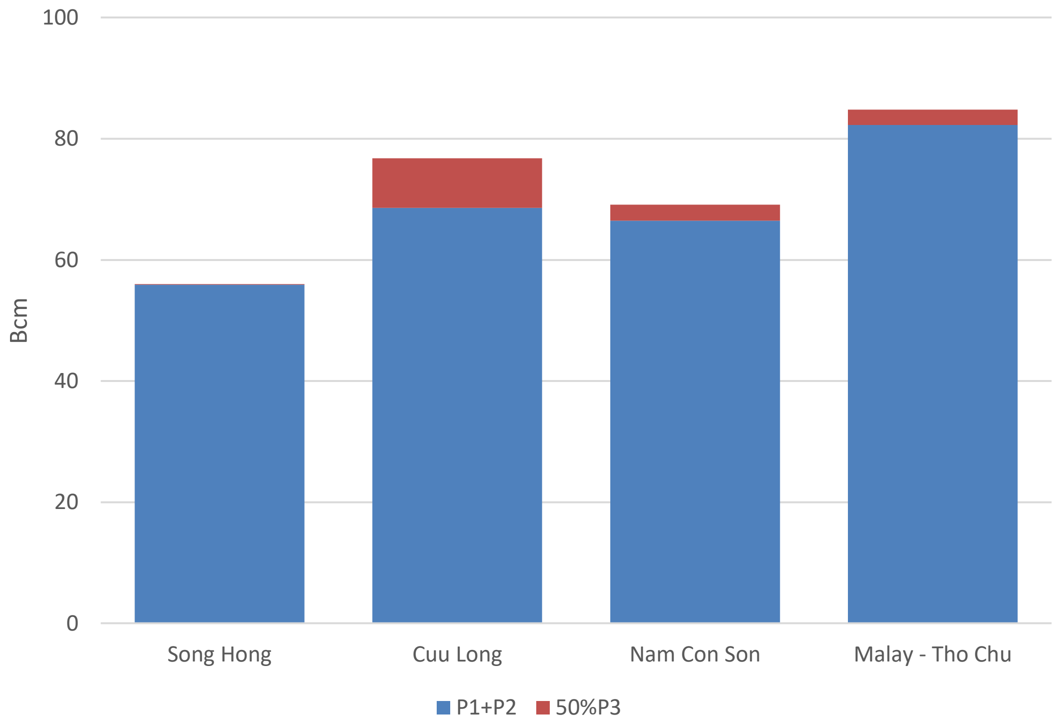


Source: 2016 Gas Master Plan

Figure 12 shows the amount of gas reserves that are considered practical for extraction over the period 2015-2035; they include the reserve classes P1, P2 and 50%P3[6]. The total plausible reserves for production by 2035 is around 290 Bcm, with the Malay-Tho Chu basin expected to contribute the largest share of 85 Bcm.

[6] Reserve classes P1, P2 and P3 respectively comprise proven (at least 90% probability), probable (at least 50% probability) and possible (at least 10% probability) gas reserves. The estimated reserves combine both developed (remaining gas) and to-be-developed fields.

Figure 12 Gas Reserves Plausible for Production in 2015-35



Source: 2016 Gas Master Plan

The key options for offshore domestic reserve development that are identified in the Gas Master Plan (GMP) are set out in Table 2 along with their proposed timings from the official GMP decision. Two offshore fields that have been prioritised for development are Ca Voi Xanh and Block B. Both have challenges to be overcome in their development: the Ca Voi Xanh gas field has high carbon dioxide and sulphur concentration levels requiring additional infrastructure to reinject carbon dioxide and manage the sulphur. Similarly, Block B is a "scattered field" and will require investment in a large number of wellheads[7] to maximise production from the field.

The implications of these developments in relation to Viet Nam's gas supply outlook are discussed further in section 10.

[7] Some 1000 wellheads would be required to maximise production levels.

Table 2 Summary of Planned New Gas Fields (Domestic Fields)

Region	Gas fields	Commencement of production	Production peak (Bcm/y)	Peak period
Northern Region	Ham Rong	2018 (to 2026)	0.07-0.08	2018-25
	Ham Rong Nam – 1X	2020 (to 2027)	0.15	2021-23
	Hong Long – Bach Long – Hac Long – P4+P5	2021	0.25	2022-
	Blocks 102 & 106	2029	0.30	2030-
	Blocks 103 & 107	2030	1.20	2033-
Central Region	Ca Voi Xanh	2023	6.2	2025-
	Bao Vang	2023	0.6	2025-
	Blocks105 & 110	2030	1.20	2034-
	Blocks 111 & 113	2031	1.20	2033-
South East Region	Su Tu Trang (Stage 2)	2019	2.5	2022-31
	Dai Nguyet	2021	0.66	2024-30
	Sao Vang	2022	0.97	2024-28
South West Region	Block B	2020	3.84	2031-

5.2 LNG Imports

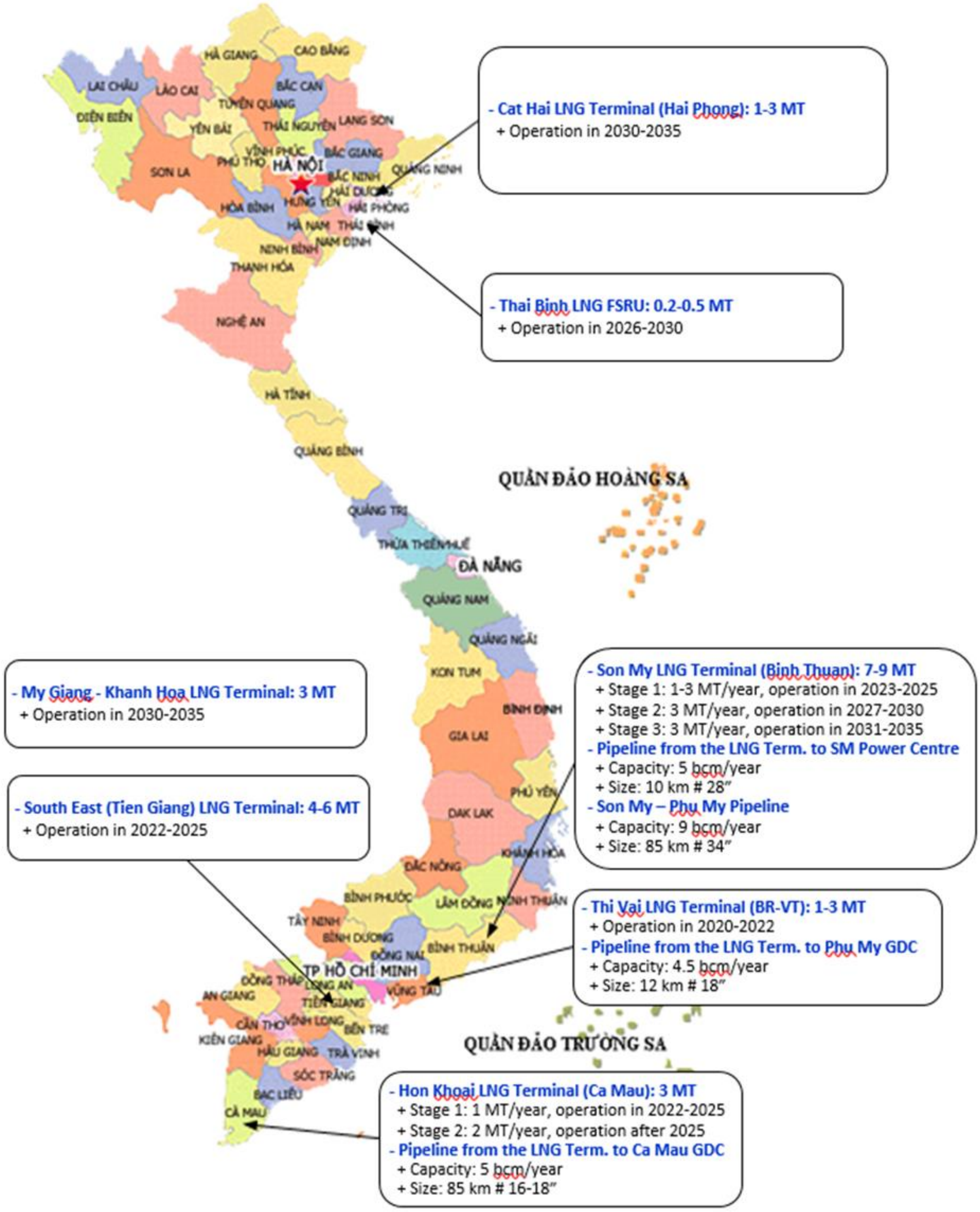
Viet Nam is also exploring the development of imported LNG under a broad strategy of offsetting the expected depletion from the current fields over the next decade. We present the key options that have been identified for development in the GMP in Table 3. Figure 13 illustrates the locations of planned LNG developments. We make the following observations: (1) the terminal sizes are significant and (2) a substantial amount of investment would be required for all LNG terminals listed to be realised.

The implications of these developments in relation to Viet Nam's gas supply outlook are discussed further in section 10.

Table 3 Proposed LNG Import Terminals

No.	Location	LNG Import Terminal	Year of Operation	Capacity	Main users
1	South East	Thi Vai (Ba Ria – VT)	2020-22	1-3 MT	Nhon Trach 3&4 CCGT
2	South West	Hon Khoai (Ca Mau)	2022-25 (st. 1) 2025- (st. 2)	1 MT & 2 MT	Kien Giang and O Mon Power Centres, Ca Mau GDC
3	South East	Tien Giang	2022-25	4-6 MT	-
4	South East	Son My (Binh Thuan)	2023-25 (st. 1) 2027-30 (st. 2) 2031-35 (st. 3)	1-3 MT, 3 MT & 3 MT	Son My Power Centre, Phu My GDC
5	North	Thai Binh FSRU	2026-30	0.2-0.5	-
6	North	Cat Hai (Hai Phong)	2030-35	1-3 MT	Hai Phong 3 CCGT
7	Central	My Giang (Khanh Hoa)	2030-35	3 MT	-

Figure 13 Locations of Planned LNG Developments (PVN)



Source: GMP / PVN

5.3 Other Development Options

Other key development options in relation to onshore / offshore pipeline infrastructure and gas processing plants that have been identified in the GMP for the Southeast and Southwest regions is shown in Figure 14. Major offshore projects total capacity of 11 bcm are Bach Ho-Phu My and Nam Con Son pipelines in South-East, and PM3-CAA - Ca Mau pipeline in South-West). Onshore distribution networks include Phu My-My Xuan-Go Dau (15 km) and Phu My-Ho Chi Minh City (71 km).

Figure 14 Major Gas Pipeline Projects in the Southern Regions

Source: GMP / PVN

A detailed description of key gas infrastructure developments is provided in Appendix B.

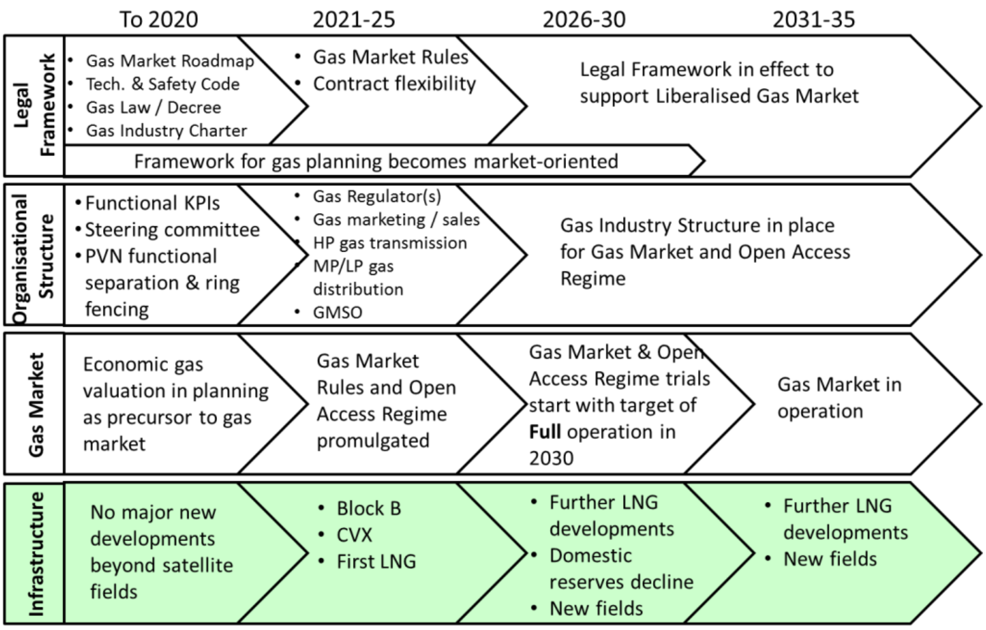
5.4 Implications for Gas Market Development

The key implication for gas market development is that whilst each of the development options listed in this section could have consequences for the outcomes within a gas market, the broader framework of any gas market (and liberalisation steps) must be able to cater for any order or sequencing of these development options. Moreover, the gas market should have flexibility to absorb the potential risk associated with possible delays in major supply projects, especially Block B.

5.5 Transitional Steps

The development options that have been identified in the GMP may or may not proceed as planned. Irrespective, it is important for the main stages in development of infrastructure in the gas industry form part of the Roadmap to ensure that the necessary regulations and policies are synchronised with developments. Furthermore, as planning frameworks evolve towards being more market-oriented, then decisions in relation to investments and infrastructure will have less Central oversight and be made to accommodate the evolution of a gas market. Figure 15 illustrates the outlook for infrastructure development in the Roadmap, with infrastructure development path being shaded. It is important to note the tight coupling that development options have with the evolution of methods for economics and planning, which are discussed in detail in section 8 and 10.

Figure 15 Transitional Steps for PVN's Role in the Gas Market



PART C: GOVERNANCE AND INDUSTRY STRUCTURE

6 Governance and Institutional Arrangements

6.1 Current Governance and Institutional Structure

Figure 16 shows the current governance structure of Viet Nam's petroleum industry. This is compared with the electricity industry in Viet Nam, which is transitioning to a liberalised market. On the top line, we show the upstream and downstream gas supply chain. On the left side, we have identified the key functional areas of a liberalised gas market.

PVN organisational roles and functions are stipulated by government decree and PVN charter. PVN activities are wide ranging and span all aspects of exploration, production transportation, regulation, purchasing, distribution and sales. PVN has other subsidiary organisations[8] from banking to related businesses including the investment in production and trading of electricity and fertilizers.

In Figure 16 a separation of government policy formulation and gas market operation is shown. However, the separation of other functional areas including regulation, operation and network infrastructure necessary for a liberalised market have not yet been progressed in PVN.

Figure 16 Current governance structure of Viet Nam's petroleum and power supply[9] industry

Supply Chain	Power	Upstream	Midstream Gas	Distribution
Policy Decision & Direction	PMO			Policy
Policy oversight, policy submission to PMO and advice	MOIT			
Policy formulation, strategy evaluation & master plans	GDE/MOIT			
Market Economic Regulation	ERAV	PVN (via PV Gas)		PVN
Technical & Safety Regulation	ERAV	PVN (via PV Gas)		
Purchase	EPTC	PVN		
Market Management/Operation	NLDC	PVEP	PV Gas	PV Gas
Transmission and Distribution	NPT	PV Gas		
End Users	EVN, PV Power and IPPs			PV Gas & Non-Power Users

[8] 27 business units and 32 subsidiary companies.
[9] ERAV – Electricity Regulatory Authority of Viet Nam; EPTC - Electric Power Trading Company; NLDC – National Load Dispatch Centre; NPTC – National Power Transmission Corporation; EVN – Viet Nam Electricity

6.2 Key entities that govern Viet Nam's gas industry

6.2.1 Overview

The following are key entities that govern the Viet Nam's gas industry:

- The **Prime Minister's Office (PMO)** has direct oversight of the oil and gas industry, and the electricity industry. For oil and gas this includes promulgation of the legal framework and the final decision-making on policy, regulation and long-term planning.
- **Ministry of Industry and Trade (MOIT)** is responsible for overseeing all aspects of Viet Nam's energy sector including electricity, new and renewable energy, coal, and the oil and gas industry. It has specific responsibility for formulating and submitting to the Government draft laws, decrees and policies; preparing and submitting to the Government, or the Prime Minister for approval overall development strategies and master plans; promulgating circulars, decisions, directives and other documents on state management and regulation for the listed sectors and fields. MOIT under PVN Charter Article 24 "is the direct superior of PVN Board Directors".
- **General Directorate of Energy (GDE)** was established in September 2011 to carry out the function of advising and assisting the MOIT to execute the tasks of state management over the energy sector. GDE is responsible for drafting laws and decrees, preparing and evaluating development strategies and national master plans. GDE is responsible for national energy planning and energy policy, but is not involved in the day-to-day management of Viet Nam's energy industry. In relation to energy planning, GDE/MOIT prepares separate national development plans (also called master plans) for the power, coal, gas and petroleum sectors.

6.2.2 PetroVietnam

PetroVietnam (PVN) is the state-owned and state-controlled Viet Nam Oil and Gas Corporation. At present, PVN's organisation, roles and functions are stipulated by Government's Decree No. 149/2013/ND-CP dated 31 October 2013. PVN activities span all aspects of the oil and gas industry, including oil and gas exploration, production, storage, processing, transportation, distribution and other related services. Under PVN Charter Article 9, the State delegates PVN "to carry out petroleum exploitation and exploration activities on the total Viet Nam continental and signing oil and gas contracts with organizations and individuals that conduct Viet Nam oil and gas activities in accordance with the provisions of the petroleum law and other provisions of law". PVN, under the direct control of the PMO, maintains regulatory control over end-use oil and gas prices and most other aspects of the oil and gas sector. Different aspects of PVN are managed through various wholly or partly owned subsidiaries.

PVN Charter Article 4 - 2a & 2b states that core business is wide-ranging and includes "Petroleum research, exploration, production, transportation, processing, storage and distribution of oil and gas products at home and abroad; trading and distribution of oil and gas products, petrochemical materials; and related businesses such as investment, production and trading of electricity and fertilizers."

Some of the key PVN wholly-owned subsidiaries include:

- **PetroVietnam Exploration and Production Corporation (PVEP)** - is responsible for upstream gas and oil exploration and production activities in Viet Nam and the management of PSCs.
- **PetroVietnam Gas Corporation (PVGas)** - manages the midstream and retail gas activities in Viet Nam, and is the sole entity that links gas from the upstream gas supplies to the end-users of gas. PVGas has sole rights to distribution network[10] development. PVN has regulatory control over all facets of gas transportation (via PVGas) and downstream oil and gas marketing.
- **PetroVietnam Power Corporation (PV Power)** - was established in 2007, and manages power projects for PVN. While the focus of projects was initially gas-fired power generation plants, the company has started the process of diversifying their power plant portfolio to include hydro, coal and wind projects.

PVN Charter Article 81 indicates that PVN reorganization is decided by the Prime Minister when necessary after it is requested from the Ministry of Industry and Trade and the process follows the order and procedure of law. The Draft GMP (2016)[11], prior to 2025, "recommends to retain the current governance arrangements of the gas sector. Government's targets of managing, controlling the gas market are being achieved completely. The Government is effectively regulating the market operations via PVN and PVGas."

Post 2025, the Master Plan targets "the establishment of the gas regulatory agency to assume the functions in regulating gas transport, distribution and trading activities, to gradually reduce Government's involvement in governing the gas sector, consistent with the wholesale competitive market model and retail market model (post 2030)".

6.2.3 Other state-owned enterprises in Viet Nam's energy sector[12]

The following are some other important state-owned enterprises:

- **Electricity of Viet Nam (EVN) -** was established in 1994 as the state-owned integrated power utility. EVN controls transmission/distribution and over 80% of generation capacity.
- **Vinacomin -** founded in 1994, is Viet Nam's state-owned coal miner accounting for 91% of the country's total coal output. It is also involved in the power market in Viet Nam, with plans to increase its coal-fired power generation portfolio.
- **Petrolimex** or **Viet Nam National Petroleum Group**, an industry group in Viet Nam, is an oil and gas producing company in competition with PVN. In addition to operations in petroleum and natural gas, the company has significant subsidiaries active in insurance, transport and trading.

[10] Wood Mackenzie Viet Nam gas and LNG - 2016 long term regional outlook, July 2016 page 7
[11] Gas Master Plan Chapter 9 Section IV.2
[12] Wood Mackenzie Viet Nam gas and LNG - 2016 long term regional outlook, July 2016 page 7

6.3 Governance and Institutional Challenges to Market Development in Viet Nam

6.3.1 Industry governance

A liberalised market is built on an industry governance structure that unbundles policy, regulation and system management and market operations and separates the contestable elements of the market from the natural monopoly of networks, pipelines and critical infrastructure.

Functional separation and restructuring is a precondition for progressing a liberalised market. Functional separation provides business transparency. Provided it is properly executed, it avoids perceived conflicts and biases in market operation and regulation and thereby reduces risk to future investors who need to be able to rely on the fair and transparent workings of the market.

The electricity sector has taken the first important steps to restructuring EVN in preparation for market liberalisation and the required functional separation for PVN is similar.

PetroVietnam remains constituted as a State-Owned Enterprise with a charter to develop Viet Nam's oil and gas resources and infrastructure across the whole supply chain. A large and complex corporation, PetroVietnam has many functions and responsibilities with the potential for conflicting objectives, strategy and operational priorities. It has subsidiary businesses with mixed responsibilities including regulating the industry, buying and selling gas, transporting gas, delivering infrastructure and advising the Ministry of Industry and Trade and the Prime Minister's Office on matters of energy policy.

The draft GMP (2016) recommends retaining the current governance arrangements of the gas sector beyond 2025. A PVN charter that continues to preserve PVN's monopoly over all elements of gas supply chain and includes subsidiaries and interests inconsistent with its core functions and priorities would be is likely to be an impediment to meaningful progression to a liberalised gas market.

These issues are of importance to progression of the gas reform roadmap. PVN's diverse interests create potential for bias and a lack of independence if PVN is to have a mandate to provide non-discriminatory open access and market operator roles in a future liberalised gas market. The required changes to the role and structure of PVN are described in Section 5 and changes to the gas planning framework are described in Section 7.

6.3.2 Regulatory & legal framework requirements

The regulatory and legal framework within which the energy market operates is fundamental to the successful delivery of energy market reform. The regulatory and legal framework allocates decision making responsibilities to parties and provides the tools and mechanisms to implement them.

The current regulatory or legal framework in place in Viet Nam would not support the development of a gas market. PVN has regulatory control over all facets of the petroleum industry in Viet Nam, including upstream oil and gas, gas transportation (via PVGas) and downstream oil & gas marketing. PVN and PVGas self-regulate without independent oversight. Internal procedures are managed by PVN/PVGas on a project by project basis. Prime Minister's Directions on gas prices and gas allocations apply to specific situations, without general industry application.

The current challenges for the regulatory and legal framework for reform are threefold[13]:

- *"To separate market development from broader energy policy setting:*
  - Legal and regulatory arrangements need to be established with the force of Law;
  - Market development and reform requires resources and expertise committed to timely implementation.
- *To separate rule making and market development advice, rule enforcement and compliance:*
  - Transparent and independent gas regulation with appropriate powers and functions.
- *To bring greater clarity and transparency to the roles and objectives of the governance institutions, and to the decision-making processes:"*
  - unbundle policy, regulation and system management and market operations; and
  - separate the contestable elements of the market from the natural monopoly of networks, pipelines and critical infrastructure

The regulatory and legal framework will need to take account the interrelationship between gas and the power market in Viet Nam, the policy challenges facing the government and regional market issues relevant to Viet Nam.

Regulatory rules and market design will necessarily adapt[14] and change, however the legal and regulatory framework should remain consistent, transparent and robust in the face of these challenges, inviting confidence and trust in market processes and delivering competitive neutrality of resources, technology and regulation[15].

The gas regulatory and legal framework can provide the vehicle to honour legacy contracts and current contracts being negotiated and the opportunity, if progressed, to trade and re-negotiate contracts to liberate unutilised capacity and deliver a more efficient allocative economic value.

In line with Viet Nam's transition to a liberalised power market, the regulatory and legal framework of a domestic gas and LNG market will need to separate high level policy direction from rule making and independent advice. A body responsible for economic regulation and

[13] Framework reflects Australian Energy Market Commission (AEMC) response to Independent Review into Future Security of the National Electricity Market (Preliminary Report December 2016, Dr Alan Finkel AO, Chief Scientist), page 8.

[14] The regulatory framework will be established by Law. However, market rules and technical regulation must be able to adapt and respond to a changing landscape. Changes would follow regulatory review processes and consultation and would be implemented by ministry circular.

[15] This is all about establishing rules that neither favour nor prevent particular technologies from being used. Regulation does not seek to pick winners. "Ensuring the regulatory framework facilitates competitive and efficient energy markets in a time of technological change" *Australian Energy Week 2016, AEMC - 21 June 2016, Australia*

rule enforcement equivalent to ERAV will need to be considered at the earliest opportunity and ahead of the GMP proposed implementation program for a sector governance model[16].

Changes to the regulatory and legal framework to meet the requirements above, are discussed later in section 11.

6.3.3 Technical & safety governance

Currently each project proponent is required to develop its own technical and safety compliance systems, with no effective guidelines from the Government of Viet Nam on minimum standards which must be met. Basic codes, based on international standards, can provide greater investment confidence and trust, particularly at the early stages of project development.

While it is acknowledged that each project will have specific requirements due to locational factors or design elements, a performance-based standard, such as the Safety Case regime widely adopted in the international oil and gas industry, with specified minimum standards, would be a worthwhile model to consider.

Reforms to the technical and safety regulatory regime will assist in delivering efficiency improvements in the gas sector. This requires the technical and safety codes presently internalised in PVN to be established as industry wide regulations, applicable without discrimination and available to all participants. The transparency of continuing improvements in the non-market aspects of regulation, operational rules, technical codes and the re-organisation of PVN will deliver efficiency benefits regardless of progressing gas market liberalisation.

The importance and the role of market rules applied through technical and safety codes is:

- the uniform application to PVN;
- the signal and transparency it provides to new market entrants; and
- the foundation of confidence and trust it brings to market participants, new entrants and investors.

6.4 Steps towards Functional Separation in the Gas Supply Chain

Presently all key market functions in relation to the management of gas resources and the development of a domestic gas and LNG market in Viet Nam are embodied within PVN. Functional separation is a pre-condition for progressing a liberalised gas market. The steps and roadmap to a liberalised gas market are detailed below:

- Step A – Separation and ring-fencing of PVN key market functions from other business activities;
- Step B – Unbundling gas transportation; and
- Step C – Create a gas balancing and secondary trading market.

[16] See GMP Chapter 9 IV.2. State sector governance model - post 2025

These steps should then create a regime in which investors can develop pipelines and other infrastructure to bring gas to market, and multiple upstream gas suppliers can sell gas to multiple purchasers. In other words, a gas market will have been created, as follows:[17]

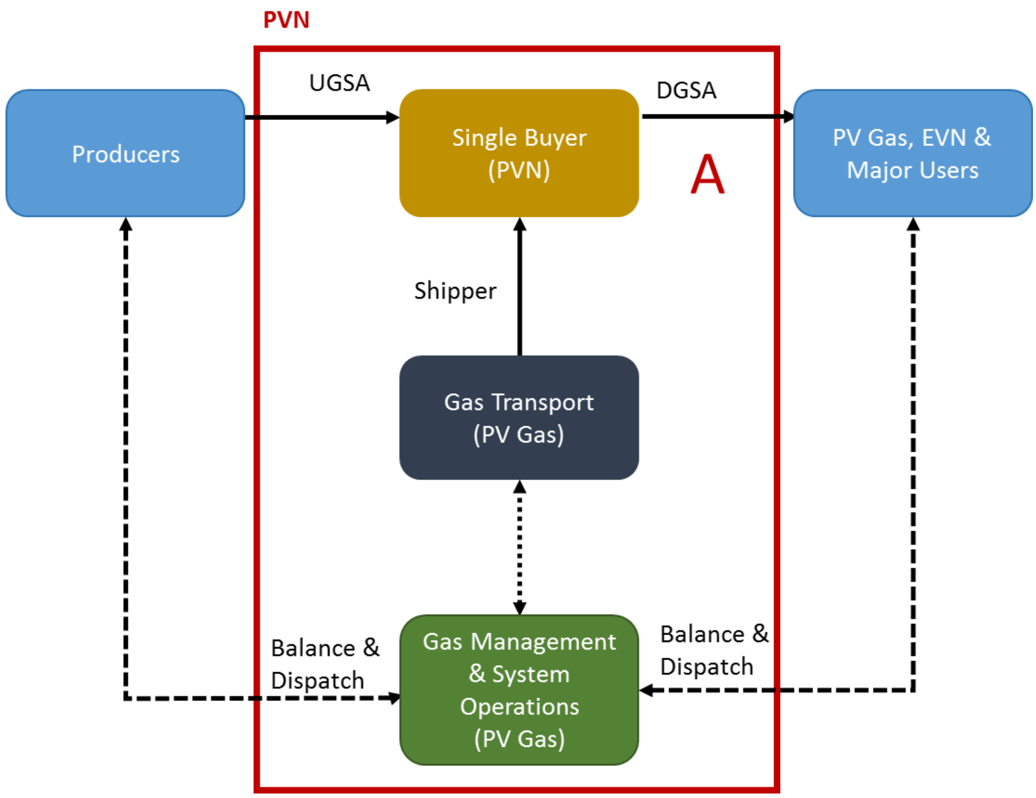
- Step D – Development of further pipelines by third parties in addition to PVN; and
- Step E – Competitive purchase of domestic gas and LNG – i.e. multiple buyers.

6.4.1 Step A – Separation and ring-fencing PVN key market functions for other business activities.

The first step is the functional separation and ring-fencing of PVN roles of Single Buyer (purchasing gas from producers and selling gas to users); Gas Transportation; and Gas Management and System Operation (GMSO) from PVN's other functions and business activities. Having ring-fenced these functions their operations may be unbundled, leading to full separation into stand-alone entities as per the following steps B to D.

Figure 17 identifies in red these key functions that must be separated and ring-fenced in preparation for a gas and LNG market. It follows a similar separation in EVN for the electricity market.

Figure 17 Step A: Separation and ring-fencing of PVN existing key market functions



[17] Investor-owned and operated pipelines and multiple buyers and sellers of gas are both indicators of a working market. However, it should be noted that step D is not a necessary precursor to step E.

6.4.2 Step B – Unbundled gas transportation and open access regime to pipelines and infrastructure

PVN through PVGas operates all three offshore gas pipelines in southern Viet Nam. However, the ownership of Nam Con Son offshore pipeline is shared between Rosneft and Perenco[18]. PetroVietnam Low Pressure Gas Distribution, a subsidiary of PVGas, distributes gas supplies to industries via the onshore pipelines. PVGas is the sole entity that links gas from the upstream gas supplies to the end-users of gas. PVGas has the sole rights to distribution pipeline development.

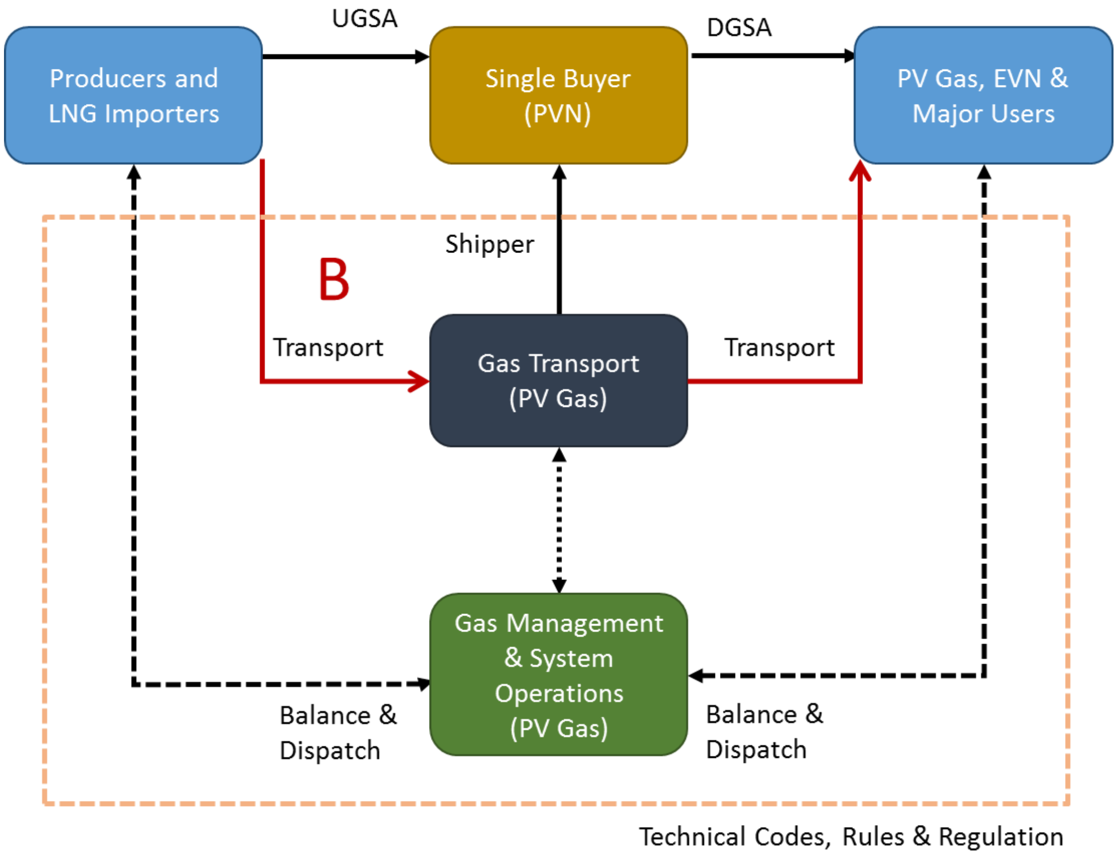
Gas transmission and distribution contract charges are approved by Government on a project basis. PVN gas purchases are supported by gas transport service contracts between PVN and PVGas which cover the gas collection, transport and operation services provided by PVGas on behalf of PVN.[19]

As shown in red in Figure 18, unbundling transport is a key step to establishing a non-discriminatory open access regime to gas and LNG pipeline transportation (separate from all purchases and sale of gas). For each pipeline, a transparent and non-discriminatory regime would be required to be published for connection and for the cost of transportation services. This also requires technical & safety codes presently internalised in PVN to be established as industry wide regulation applicable to all gas market participants.

A non-discriminatory access and pricing regime for domestic gas and LNG pipeline transmission and distribution is absent in the current market. Unbundling PVGas would require transfer of legacy gas purchase contracts for the Nam Con Son basin to PVN, to become the entity providing gas infrastructure (transportation and distribution)[20] as distinct from gas supply.

[18] 10Z 0073 Wood Mackenzie Viet Nam gas and LNG 2016 long term regional outlook.
[19] 21 0125 - VN gas industry models, Gas Trading Mechanisms, DGSA contracting arrangement - page 2.
[20] 21 0125 - VN gas industry models, Proposed Models for GAS Industry Development in Viet Nam - page 3.

Figure 18 **Step B: Unbundling gas pipeline transmission and distribution providing non-discriminatory access regime for gas transportation and connection.**



6.4.3 Step C – Create a gas balancing and secondary trading market

Current contracts preclude any secondary trading. PVGas's existing dispatch and balancing market operations could provide the mechanism for wholesale market participants to renominate and optimise gas requirements. This would require that flexibility to be available in contracts. If incremental volumes of domestic gas and LNG were made available at a regional reference price, wholesale participants could purchase and trade around existing contract entitlements balancing their daily needs. Subject to flexibility of current contract provisions and future sales agreements a secondary market may release pipeline capacity, provide access to un-utilised gas entitlements and optimise gas volumes purchased and sold in the market.

Take or Pay provisions of current contracts may not optimise the current requirements of gas. The maximum demand quantities and committed volumes of gas may be underutilized and in aggregate result in sub-optimal utilization of transport and production infrastructure. Periods of imbalances in demand and supply, such as due to plant curtailment and maintenance, present market opportunities for alternative and more flexible supplies of LNG and domestic gas, physical and financial gas trading and the re-sale of gas entitlements.

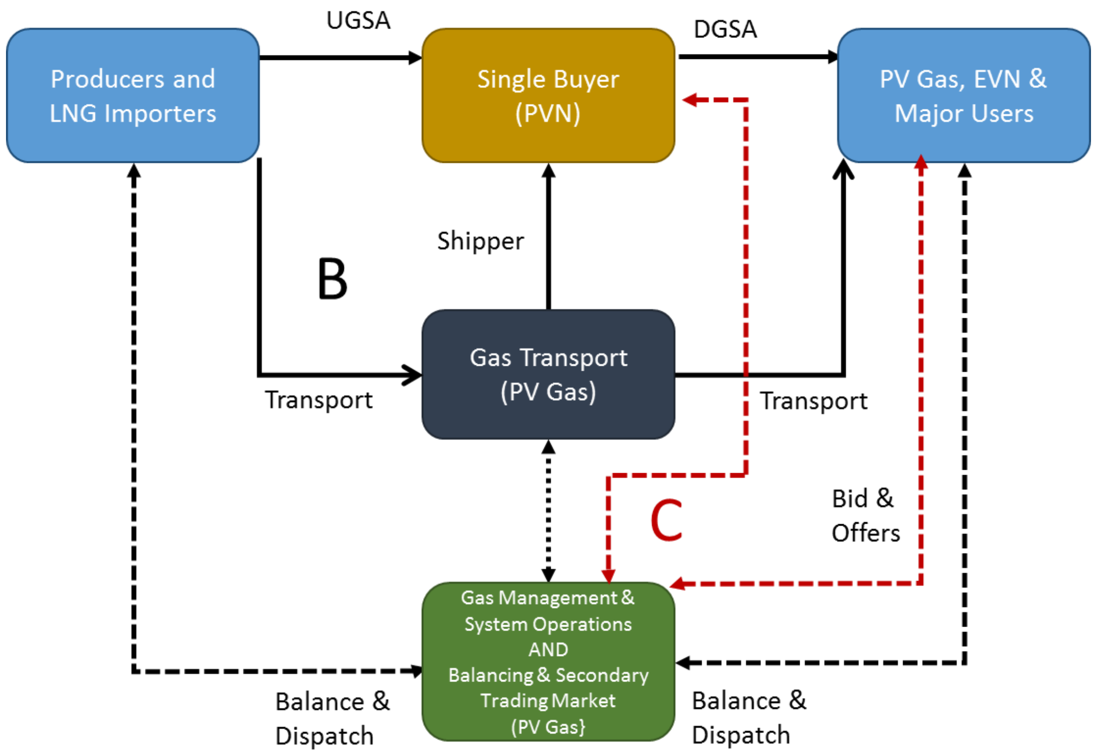
Having structurally ring-fenced purchasing, transport and operation, the first steps to a gas market as shown in red in Figure 19 can proceed. Balancing is a centrally controlled process undertaken and continuously monitored by the Gas Management and System Operator (GMSO) every day. A balancing and secondary trading market will permit wholesale market participants to review their gas needs and re-nominate their requirements. This can involve the purchase of additional gas volumes or provide opportunities to sell existing gas entitlements. The sale would release and monetise the value of unutilised gas entitlements making this gas available to other participants.

PVN as single buyer would continue to purchase incremental production and trade volumes in the secondary market as shown in red in Figure 19. The gas market would be an extension of the GMSO role. When PVN is relieved of its single buyer role (as shown in Step E - Figure 21), participation of multiple buyers and gas producers will have been enabled, thus creating a 'gas market'.

Market information and trading platforms that would support a balancing and gas secondary trading market include:

- Market bulletin boards to register and exchange trades;
- Gas regional hub providing regional reference prices and trading platforms; and
- On market and off-market gas swaps facilitated by third parties.

Figure 19 Step C: Establish a balancing and secondary trading market building on the existing balancing market to optimise & trade gas entitlements



6.4.4 Step D – Development of pipelines by third parties in addition to PVN

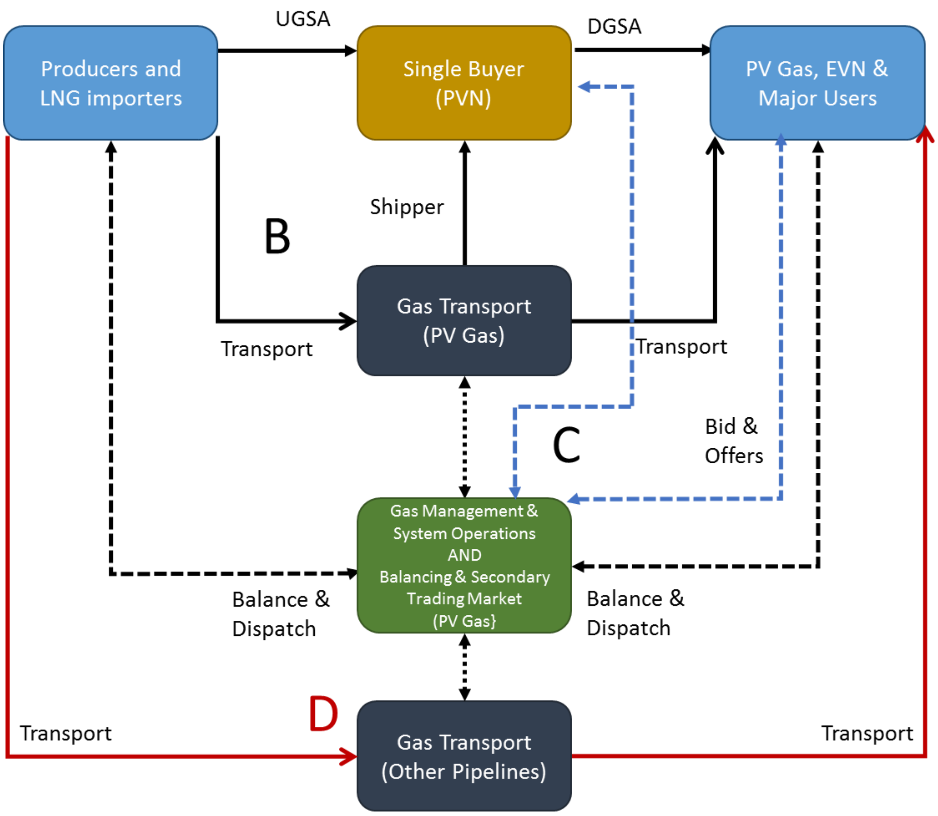
As shown in red in Figure 20, a non-discriminatory access regime will allow private sector investment in gas transport infrastructure to proceed. Third parties may be permitted (from a nominated time) to develop new pipelines for connection to new gas resources, LNG infrastructure and power generation developments. The opportunities for pipeline interconnection between resources may increase bringing competition in the bundled package of domestic gas supply and/or LNG together with associated pipelines.

Not all pipelines necessarily serve or connect multiple users and buyers. There remains a role for both covered (regulated) pipelines and uncovered (independent or private unregulated) access arrangements not suitable for open access. Different approaches may apply to pipeline developments as Viet Nam LNG and domestic gas development shifts from point to point resource (infrastructure) development to targeted network interconnection and gas market law and associated rules would need to include this distinction and associated criteria.

Economic regulation provisions would apply only to 'covered' pipelines. Various tiers of regulation may apply, based on competition and significance criteria. Full regulation would require a pipeline provider to periodically submit an access arrangement to the regulator. Under light regulation, the pipeline provider may determine its own tariffs, but would be required to publish relevant access prices and other terms and conditions and to offer them to all parties on a non-discriminatory basis.

Some pipelines (particularly including offshore pipelines) may remain 'uncovered', meaning that for various reasons they are unsuitable for open access and remain not subject to economic regulation. Gas pipelines associated with project specific development in disconnected regional areas may remain 'uncovered'. However, all pipelines would be expected to comply with technical and safety regulations.

Figure 20 Step D: Permit other parties to develop new transmission and distribution pipelines and offer transportation (shipping) services



6.4.5 Step E – Competitive purchase of domestic gas and LNG – multiple buyers

Currently purchases and sales of all gas are controlled by PVN in its role as the single buyer. The majority of gas supply agreements are bilateral negotiations with direct supply agreements between PVN and power producers and between PVN and other commercial users including the fertiliser industry. PVGas has the role of managing and operating the gas pipeline system and gas processing facilities. Contracts between PVN and PVGas cover the gas collection, transport and operation services provided by PVGas on behalf of PVN. Some legacy gas purchase contracts have been signed between PVGas and producers (Nam Con Son basin), under PVN approved gas prices.

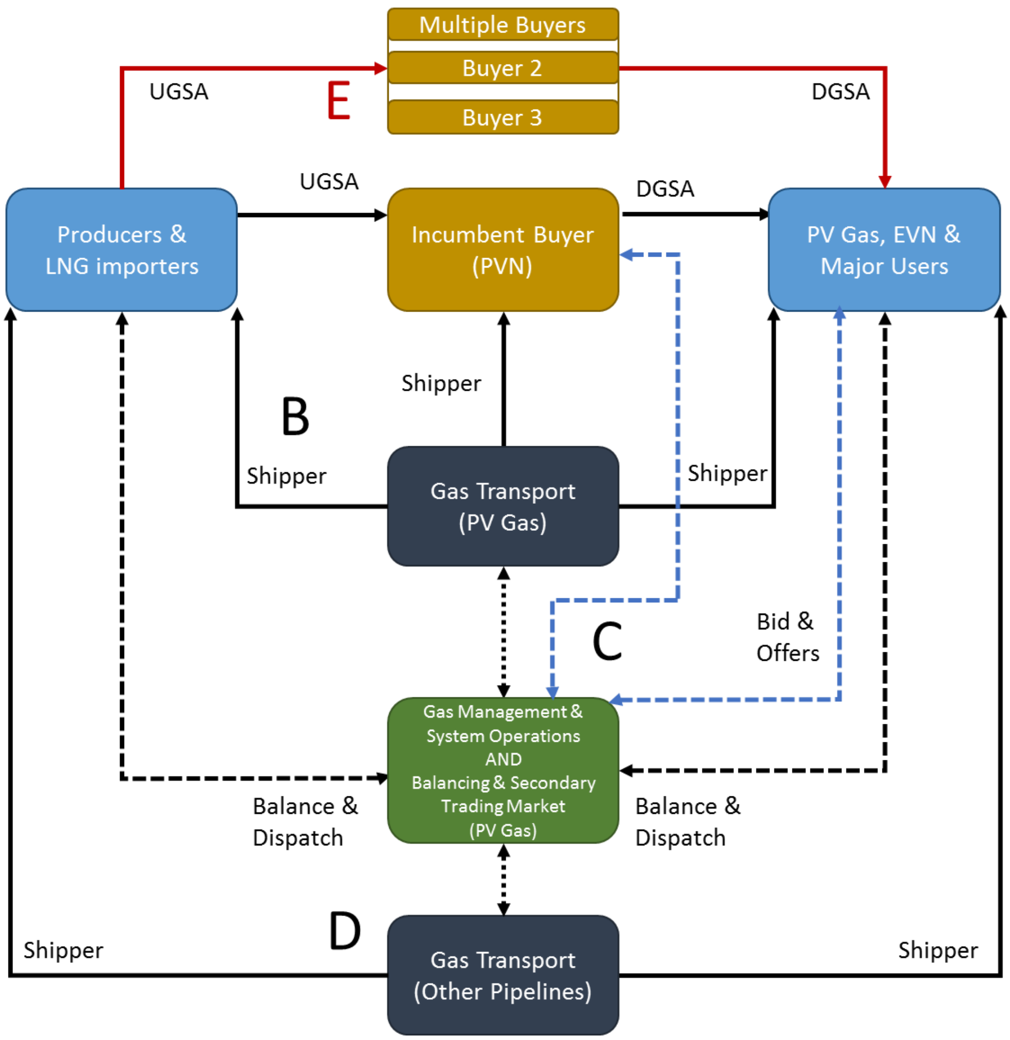
In all the previous steps (see Figure 17 to Figure 20), PVN can continue as the "Single Buyer" responsible for upstream gas and oil exploration and production activities in Viet Nam and the contracting management of PSCs.

Having progressed a regulatory access regime and gas market framework, the entry of third parties to purchase and sell gas is enabled, and PVN can be relieved of its single buyer role. This is shown in red in Step E - Figure 21. LNG importation should present an early opportunity for the entry of multiple buyers, increasing market liquidity and competition with the incumbent PVN Buyer.

Access to and competition between multiple gas resources and LNG suppliers will advance by increased interconnection through pipelines and electricity transmission, and the progress in LNG and gas resource developments.

Using LNG imports as a basis for starting to liberalise gas prices has been implemented worldwide, in particular in the Chinese gas market china, the pricing model of which is discussed in section Appendix E as part of our review of international examples.

Figure 21 Step E: Competitive purchase of domestic gas and LNG – multiple buyers



6.5 Future Governance and Institutional Arrangements

6.5.1 Regulatory and legal framework

The following actions are recommended to progress a legal and regulatory framework:

- Market reforms must be supported by Gas Law and a decree on industry restructuring;

- Clearly separate high-level policy direction from rule making and independent policy advice;
- Establish an independent gas economic regulator similar to the power industry's ERAV with the appropriate powers and functions;
- Formulate a high-level, overarching (principles-based) framework to guide operations e.g. market rules, access arrangements, technical standards and safety codes;
- Establish a legal and regulatory framework for a domestic gas and LNG market (rather than a set of processes implemented internally by PVN/PVGas);
- Provide an integrated approach to Gas Master Plan synchronised with related Master Plans (Power and Environment) and government policy initiatives.

In progressing a regulatory and legal framework, low hanging opportunities will provide the initial steps to a liberalised market. These include the introduction of a balancing and secondary trading market for gas and non-discriminatory access regime for gas transportation and connection. A focus on market segments or niche regional opportunities (for example, where multiple buyers and multiple sellers are concentrated in a particular region, or at a major electricity or gas transmission node) will provide the beach head for competition and market based pricing. Strategically located terminals for LNG may provide flexible competitive sources of gas competing with domestic gas and imported coal.

6.5.2 Modified industry structure

Functional separation of relevant industry roles is a precondition for progressing a liberalised market. This includes functional separation of some industry roles currently in PVN, as is further discussed in section 7. This is guided by the following principles and related actions:

- Separate market development from broader energy policy setting:
  - Responsibility for gas market development should remain with MOIT. A Market Steering Committee reportable to MOIT could provide the dedicated resources and expertise for progressing market reforms and legislation program; and
  - Market reforms to be supported by Gas Law and a decree on industry restructure.
- Separate rule making, economic regulation, rule enforcement and compliance:
  - Establish an independent gas economic, technical and safety regulator(s) similar to the power industry's ERAV with responsibility and appropriate powers for industry monitoring, compliance and enforcement.
- Bring greater clarity and transparency of market roles across the supply chain:
  - Functional separation and ring-fencing PVN's key purchasing, transport and gas management and system operation functions;
  - Establishing a non-discriminatory access and pricing regime to existing pipeline and gas transport infrastructure; and
  - Introduce transparent and measurable KPIs and benchmarking measures.

This may initially be progressed within the present PVN organisational structure, ensuring existing gas contracts are honoured and resource developments remain under government control. The functional components of governance and proposed unbundled industry structure would then follow as shown in Figure 22. The names are indicative and intended only to describe that functional area.

Figure 22 Governance and Institutional Structure for unbundling market functions of the existing PVN organisation[21]

Supply Chain	Power	Upstream	Midstream Gas	Distribution
Policy Decision & Direction	PMO			Policy
Policy oversight, policy submission to PMO and advice	MOIT			
Policy formulation, strategy evaluation & master plans	GDE/MOIT			
Market Economic Regulation	ERAV	Gas Regulation Authority Vietnam		
Technical & Safety Regulation	ERAV	Gas Regulation Authority Vietnam		
Purchase	EPTC	PVN Single Buyer (to migrate to multiple buyers)		
Market Management/Operation	NLDC	PV Gas Management & System Operations (GMSO)		
Transmission and Distribution	NPT	PV Gas Transmission and Distribution		
End Users	EVN, PV Power and IPPs			PV Gas & Non-Power Users

6.5.3 Technical and safety codes and associated regulation

The following actions are recommended:

- Minimise the number of agencies focused on safety & associated compliance;
- Establish a single and independent Office for monitoring, compliance and enforcement;
- Develop codes (preferably based on international standards) to guide project specific H&S procedures;
- Implement an independent and transparent consultation process for code technical and safety review and modification.
- Implement market rule and code changes by government circular.

Improvements in the non-market aspects of regulation, operational rules, technical codes and the re-organisation of PVN will deliver benefits regardless of progressing gas market liberalisation.

[21] ERAV – Electricity Regulatory Authority of Viet Nam; EPTC - Electric Power Trading Company; NLDC – National Load Dispatch Centre; NPTC – National Power Transmission Corporation; EVN – Viet Nam Electricity

6.6 Summary and Transitional Steps

6.6.1 Summary

To enable a gas market, key industry governance roles that are currently undertaken by PVN should be migrated out of PVN into other agencies. These include:

- Gas sector policy;
- Economic regulation of gas pricing and access; and
- Technical and safety regulation.

The gas market management / operator role and the transmission and distribution pipeline owner/operator roles also need to be proscribed and need to be independent of PVN's role in purchase and development of gas.

A gas market regulatory framework, economic regulatory framework and technical and safety codes and regulations need to be developed, to be administered by the agencies as above.

6.6.2 Transitional steps

The recommended transitional steps for implementing the governance and institutional arrangement in preparation for a gas market comprise the following steps:

Step 1 - to 2020

Legal Framework

- Progress Gas Law and Government Decree on Industry Structure
- Establish a Gas Industry Charter
- Develop industry wide Technical & Safety Codes (preferably based on international standards) to provide industry and project specific standards and procedural guidance.

Organisational Restructure

- Establish a Gas Market Steering Committee (under MOIT)
- PVN functional separation and ring-fencing of GMSO, HP gas transmission, MP/LP distribution, marketing and sales.
- Minimise the number of agencies focused on safety & associated technical compliance
- Implement transparent and measurable KPIs and benchmarking measures

Step 2 – 2021 to 2025:

Legal Framework

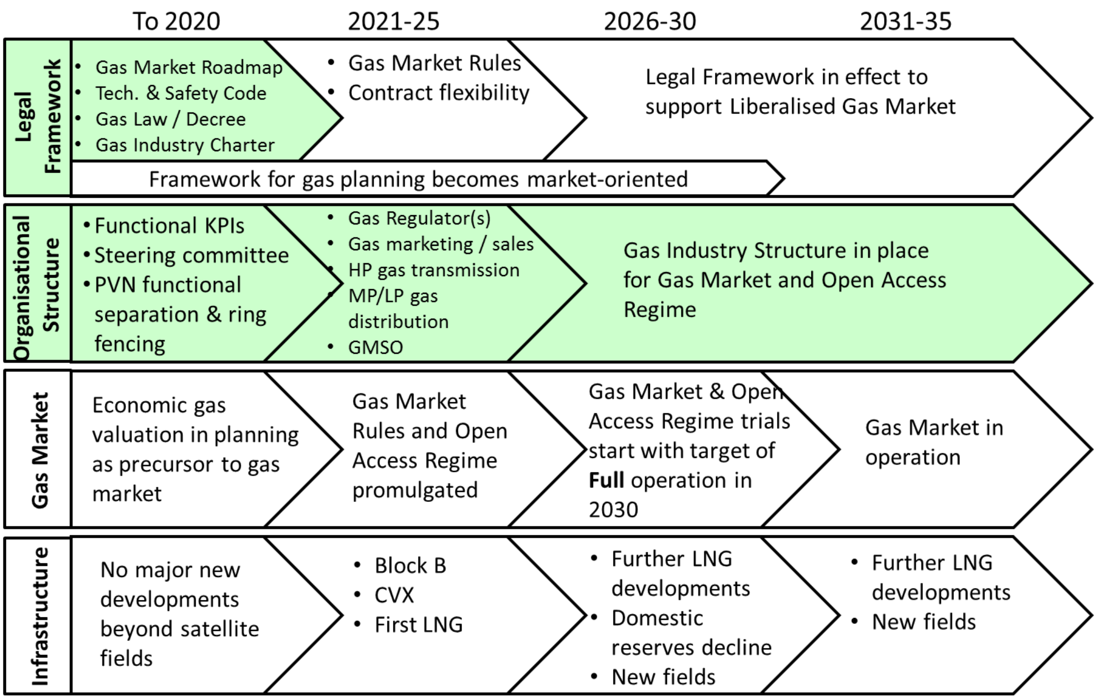
- Establish an independent gas economic, technical and safety regulator(s) similar to the power industry's ERAV with responsibility and appropriate powers for industry monitoring, compliance and enforcement.
- Implement independent and transparent consultation process for code technical and safety review and modification.

- Market rule and code changes implemented by government circular.
- Implement an open access regime for gas pipeline connection and transport.

In Figure 23, as shaded, these transitional steps and timetable for implementing the legal framework and organisation restructure are integrated into the Gas Liberalisation Roadmap.

The roadmap would ensure the gas industry structure (including open access regime for gas pipeline connection and transport) was in place for a domestic gas and LNG market to proceed. Resource and infrastructure development of LNG and domestic gas supplies would be undertaken in a manner that is consistent with the market restructure and master plans for gas and electricity market liberalisation – for example, by separating gas supply arrangements from gas transportation, making such developments subject to dispatch by an independent market operator, and subject to general technical, quality and safety codes rather than bespoke terms and conditions.

Figure 23 Transitional Steps for Governance and Institutional Structure



7 PVN's Role in the Gas Market

7.1 PVN Scope and Organisation Structure

PetroVietnam operates five core businesses:

- Gas exploration and exploitation;
- Gas trading;
- Oil exploration and exploitation;
- Electricity generation; and
- Services.

The organisation charts published on PVN's website[22] list 27 business units and 32 subsidiary companies. Each subsidiary company then has many subsidiaries, resulting in a corporate group which is complex in structure and diverse in both its operations and businesses.

The business units and subsidiaries report to the Board of Management which then reports to the Board of Directors.

PVGas is a joint stock company listed on the Ho Chi Minh City Stock Exchange with PVN holding over 50% of the registered capital; it has 15 operational divisions, owns 10 companies outright and holds interests in a further 8 subsidiary companies[23]. Many of the operational divisions, such as Health, Safety and Environment, Human Resources, Legal, Accounting and Audit, Finance, Research and Development and Information Technology replicate functions in the parent organisation, PVN.

The operations of the business units, owned companies and subsidiaries of PVN and PVGas are extensive. They span the full breadth of the oil and gas business, including many businesses which are services normally provided by independent contractors to major oil and gas companies, and equipment and materials supply and manufacture. Subsidiaries include financial services, fertiliser manufacture, shipbuilding and power generation.

7.2 Current Role of PVN

While PetroVietnam is constituted as a State-Owned Enterprise with a charter to develop Viet Nam's oil and gas resources, it also functions as the national oil company; it operates many subsidiary businesses; and it advises the Ministry of Industry and Trade and the Prime Minister's Office on matters of energy policy.

PVN's main functions[24] can be summarised as follows:

- Conduct activities and enter into contracts with other parties in the oil & gas sector, in accordance with the Petroleum Law;
- Manage, oversee operations in oil / gas investigation, exploration, exploitation and processing via contracting arrangements with other parties;

[22] www.petrovietnam.vn
[23] www.pvgas.vn
[24] Gas Industry Development Models (provided by GDE)

- Directly carry out production and commercial activities; and
- PVN has an overarching role in regulation of the gas value chain and gas industry investment, including:
  - overseeing the operation of the sector on behalf of the state / government;
  - being the upstream producer in gas exploration, production and sale (PVEP);
  - being the gas purchaser and distributor (PVGas); and
  - being a gas user for those power plants and fertilizer works owned by PVN.

These main functions and PVN's Charter allow PVN to be involved in the broad range of industry sectors in which it operates.

PVN's size, diversity, current structure and roles are incompatible with the operation of a competitive gas market as PVN operates in every area of the industry, with no apparent segregation of roles. However, there are opportunities to re-structure PVN's business into ring-fenced business units that would be compatible with a gas market, with each business unit focussed on specific areas of activity, to increase efficiency, and to grow the overall value of PVN to the national economy.

PVN is one of the most significant enterprises operating in the economy of Viet Nam, accounting for approximately 20% of national GDP. Accordingly, PVN's role goes beyond the oil and gas industry and therefore any changes to the gas industry must consider the impact on PVN and how that impact might flow through to the national economy. A possible approach is set out below, but it is recommended that an organisational development consultant be engaged to develop and support the implementation of a business-specific plan, including separation of accounting, legal, ICT, human resources and other corporate functions.

7.3 PVN Role in a Liberalised Gas Market

PVN can continue to have a pivotal role in any gas market in Viet Nam. However, a more suitable platform for competition involving the introduction of new players would require some form of re-organisation of the company so that complementary functions are grouped together. Consistent with the market-compatible industry governance structure proposed in section 6, a re-organisation of existing PVN roles could be as follows with those roles not directly related to PVN's core businesses being devolved to MOIT or other agencies, or established as stand-alone corporations:

- Gas exploration and exploitation;
- Mid-stream infrastructure development and operations;
- System (and market) operations;
- Gas trading;
- Support services, including HSE, HR, finance, accounting, ICT;
- Technical and safety regulation;
- Economic regulation;
- Policy advice to Government; and

- Non-oil and gas businesses.

Under this model, the regulatory and policy functions could be transferred to GDE, with the technical and commercial functions remaining within PVN. Appropriate ring fencing between the various functions within PVN would be required to ensure that operational decisions are taken in the best interests of the operation of the market and not solely for any business unit of PVN, and to provide an environment in which third parties will be encouraged to participate without concern that PVN's market power would make the market less than competitive.

Notwithstanding PVN's current roles and functions set out by the Government, the consultants suggest the longer-term role of PVN will always start with its over-arching role as Viet Nam's National Oil Company (NOC). As NOC, PVN's primary role should be to develop Viet Nam's oil and gas resources through PSC's, JV's or, ultimately, in its own right. Issues in relation to the role of PVN for consideration include:

- It must be involved in exploration, development and production (including processing) which starts with negotiation of the PSC's or JVA's;
- It must exit price setting, safety / technical regulation and approvals processes as well as advice to the government;
- It could be involved in LNG and/or pipeline gas imports from adjoining countries (to ensure adequate oil and gas capacity is available for Viet Nam's domestic market);
- It could be involved in the development, ownership and operation of transmission pipelines (if gas is to be sold at the City Gate or inlet to industrial facilities / power plants);
- If Viet Nam becomes an exporter of oil and/or gas, then the international sales of equity volumes could be the responsibility of PVN;
- Similarly, when Viet Nam seeks to invest in overseas oil and gas developments, PVN would be the vehicle for those activities; and
- It could, over time, exit all downstream activities including gas distribution, gas retail and power generation.

7.4 Barriers to Market Development – PVN Organisation

Neither the structures of PVN's business units and subsidiaries nor their reporting lines and accountabilities are clear to parties outside of PVN. The current organisation structure of PVN (including its subsidiaries) is that of a vertically integrated monopoly oil and gas company, operating in every sector of the industry. Relevantly for the development of a gas market in Viet Nam, the roles of gas developer and producer; gas transporter; gas seller; gas buyer; service provider, including financier, to each of these businesses; technical and safety regulator; and government policy advisor exist within a single organisation.

Many of these combinations of roles, such as that of gas seller and gas buyer; or gas buyer (or seller) and gas transporter, have competing interests in a competitive market. Where decisions about the commercial relationships between these competing roles are made by a single body, experience suggests that these decisions invariably lead to inefficiency, higher cost, restricted supply, and sub-optimal allocation of resources, with the most vocal or influential business units receiving preferential treatment over less favoured units, often with little commercial justification.

The perception, and usually the reality, of vertically integrated monopolies is that they often shift value between business units to the disadvantage of potential competitors or new entrants considering entering the market. This is particularly the case with very large, complex organisations with non-transparent decision processes. Accordingly, the operation of a large vertically integrated monopoly in a market is likely to deter new entrants from entering in any meaningful way because they do not believe that they can receive fair access to supply or information which is at the core of a market.

7.5 Transitional Steps

Any functional re-organisation would occur over a number of years in a series of steps, with each step bedded down before the next step is taken. As noted above, the details should be developed by an organisational development consultant with expertise in separation of a services in large organisations.

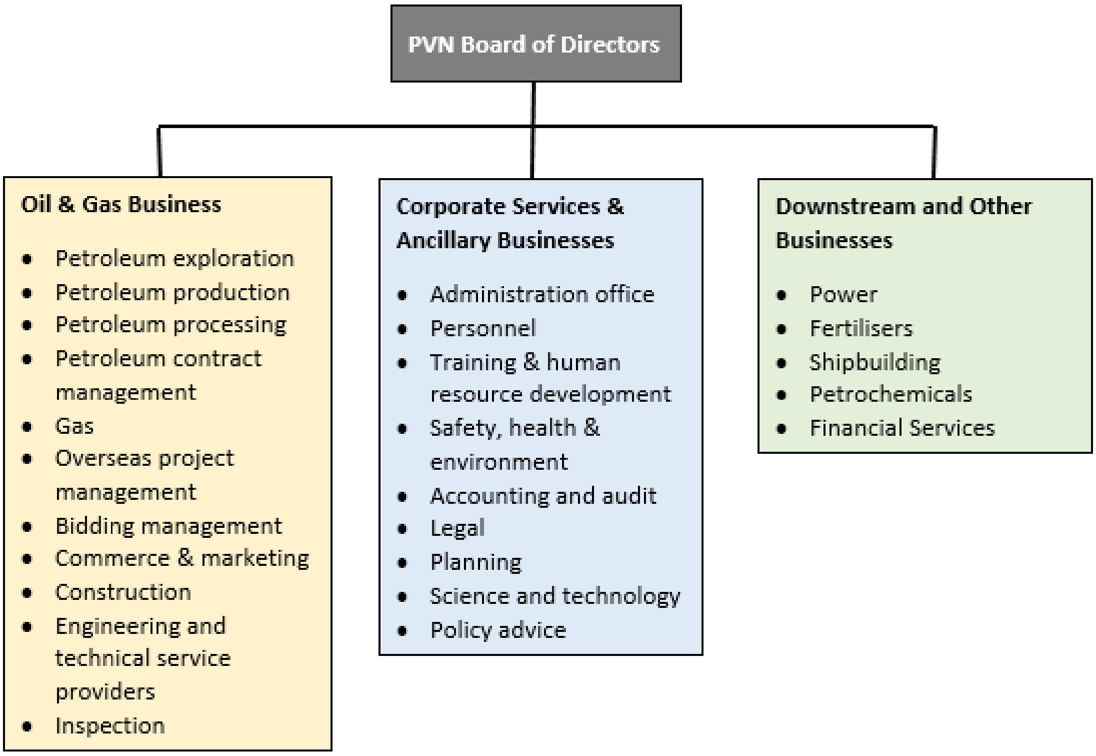
Access to data is the key to the successful operation of a market. At the earliest possible stage in the re-organisation of PVN, operational data should be made available by the system operator on an open access bulletin board to allow new market entrants to determine how and when to enter the market. An example of such a bulletin board is that operated by the Australian Energy Market Operator which can be accessed online[25].

A recommended first step would be separation of the core oil and gas businesses from the ancillary businesses such as financial services (PVcomBank, PVI, Ocean Bank, PVFI, etc) and gas customers (PV Power), DQS (ship building), PVCFC, PVFCCo (both fertilisers), Nghi Son Refinery and Petrochemicals Co, Long Son Petrochemicals Company Ltd, etc), with reporting for each business line to the Board of Directors separate from any oil and gas business reporting.

The functional structure of PVN[26] at Step 1 would be as illustrated in Figure 24.

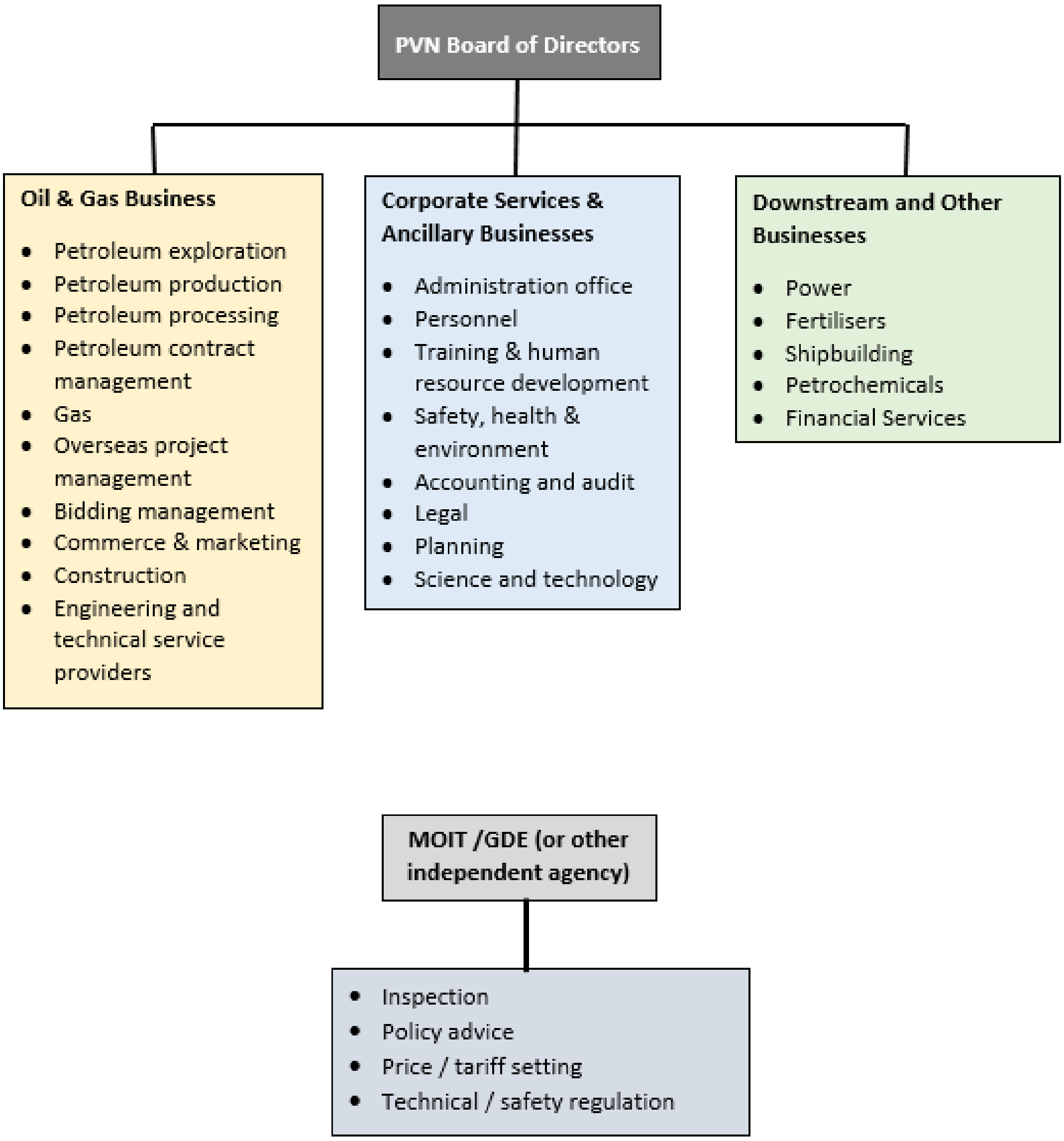
[25] See: www.gasbb.com.au and www.aemo.com.au
[26] Based on PVN Organisation structure published on www.pvn.com.vn\company profile

Figure 24 Indicative Functional Structure of PVN at Step 1



The next Step 2, Figure 25 would be for technical and safety regulation – the "Inspection" function above – and economic/market regulation (including price regulation) to be separated from any operational business unit and transferred to MOIT, GDE or a similar agency independent of PVN. These functions should oversee the operations of every operator in the oil and gas industry, including PVN.

Figure 25 Functional Structure of PVN including other functions at Step 2



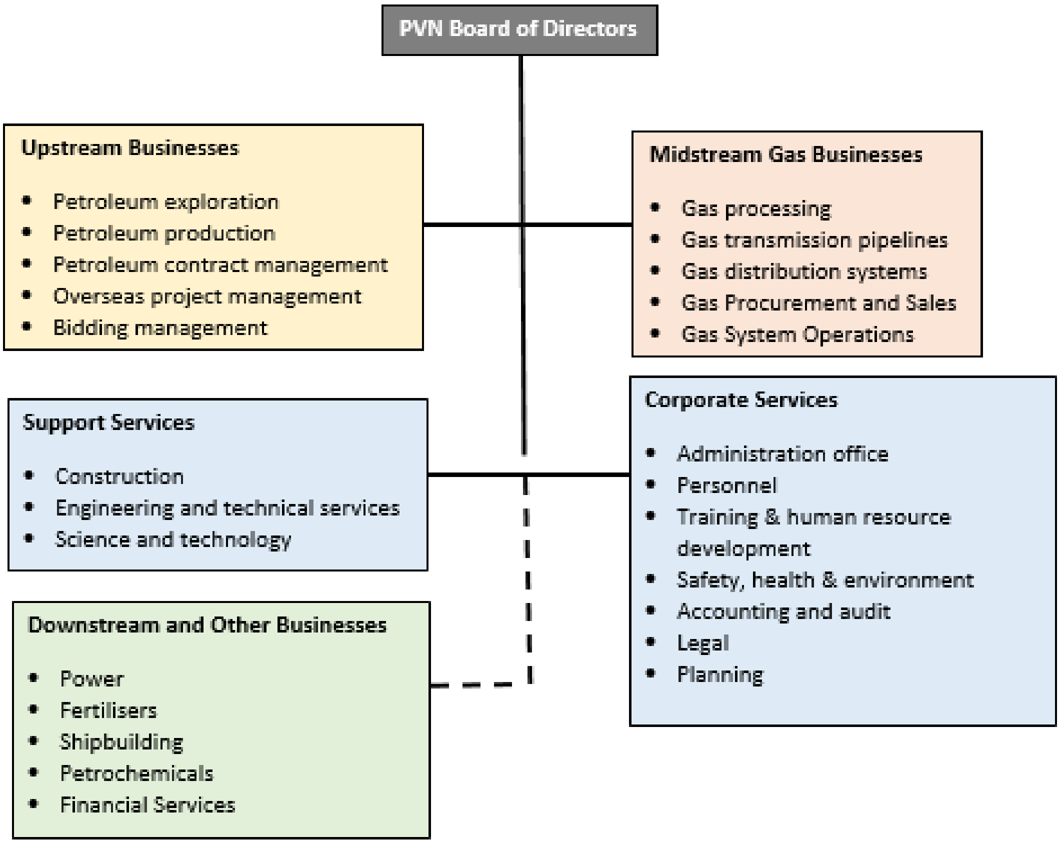
At Step 3, the services provided by engineering and technical business units and subsidiaries should be reviewed along with the engineering and technical services available within the central business units and restructured to ensure that all services are being delivered efficiently. The Construction, Engineering and Technical Service Providers, and any associated functions carried out in the Oil & Gas or Corporate Services and Ancillary Services businesses could be moved into a separate business unit focussed on providing services to the core businesses on arm's-length commercial terms. The mid-stream gas business functions would be ring-fenced from the upstream business operations.

The commercial business units – primarily gas procurement and sales would be clients of these service providers. The function of the engineering and technical business units would be to ensure that sufficient gas is available to meet the business plan and contractual obligations set out by the commercial units. Both the technical and commercial business units would be clients of the support services units (human resources, health, safety and environment, finance, accounting and audit, information technology etc.).

Depending on government policies and financial considerations, the downstream businesses could be considered for divestment.

The functional structure at Step 3 would be as illustrated in Figure 26.

Figure 26 Functional Structure of PVN at Step 3



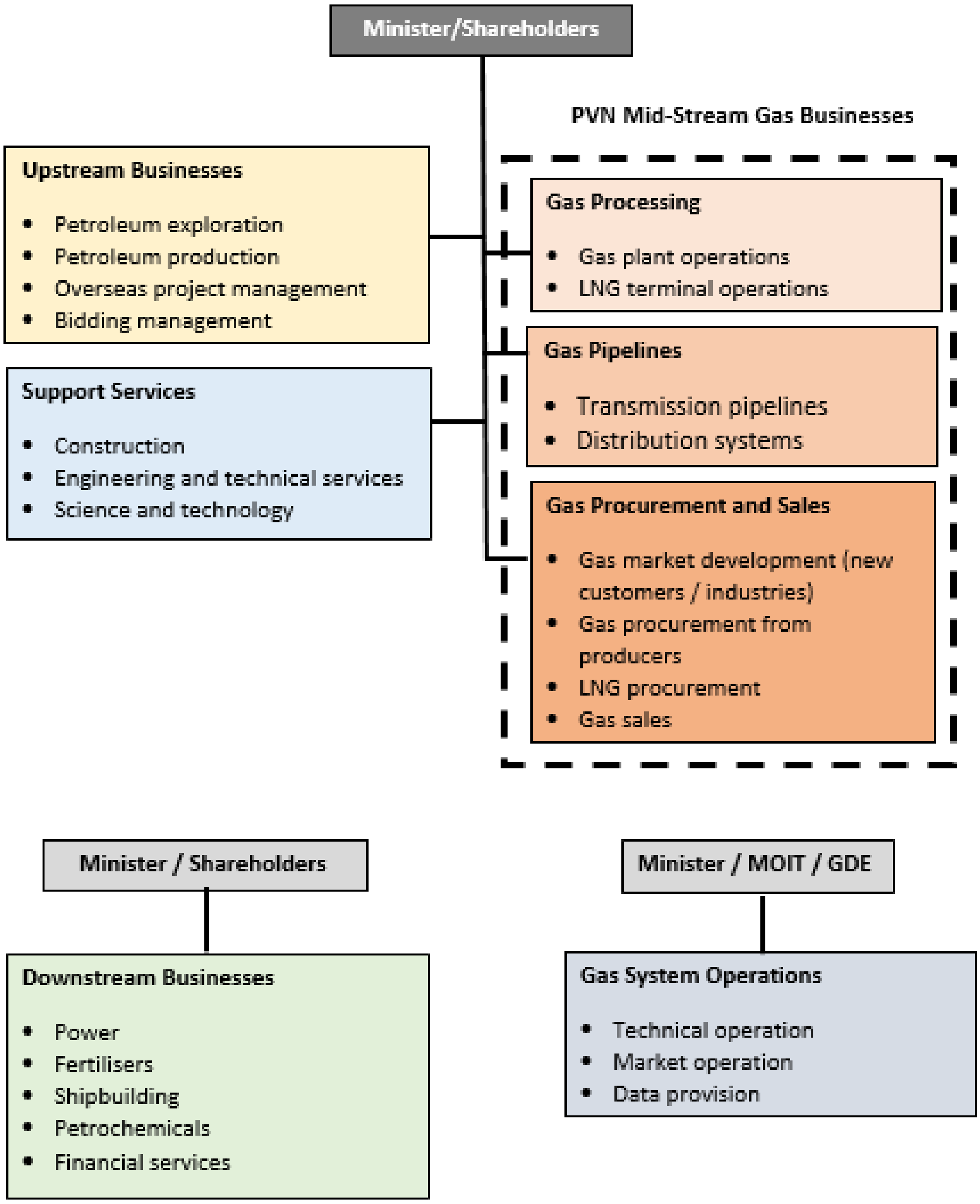
At Step 4, the mid-stream gas business functions including particularly PVGas, now separated from the upstream oil and gas businesses and service providers, can be functionally organised into separate businesses or a single business unit with three ring-fenced business sub-units as shown in Figure 27:

- Gas processing;
- Gas pipelines; and
- Gas procurement and sales.

Gas system operations should be transferred to an independent agency, with a review to consider whether there is any benefit in combining gas operations with power system operations in EVN NLDC or a similar agency.

Having determined the appropriate structure for technical operations, PVGas could be established as a service unit with accountability for system reliability from both a technical perspective (i.e. equipment availability) and a commercial perspective (i.e. meeting contractual obligations).

Figure 27 Functional Structure of PVN and the Viet Nam gas sector at Step 4



Finally, when a market is established, a ring-fenced trading business unit could be established to buy and sell gas in the market. This unit could be structured with separate upstream and downstream businesses, or an integrated gas portfolio management approach could be adopted, depending on the final market structure adopted. The downstream functions, in particular, must be fully separated from operational control by any commercial or technical business unit of PVN to ensure that it has no greater market power than any other market participant.

7.6 Summary and Transitional Steps

7.6.1 Summary

PVN reorganisation is required to bring clarity and transparency of its operational roles across the gas supply chain. The structure unbundles policy, regulation and system management and market operations and separates the contestable elements of the market from the natural monopoly of networks, pipelines and critical infrastructure. Each business unit is focussed on specific areas of activity with transparent and measurable KPIs.

7.6.2 Transitional steps

The recommended transitional steps for implementing the reorganisation of PVN in preparation for a gas market comprise the following steps:

Step 1 – to 2020

- Non-oil and gas businesses separated from all oil and gas activity
- Technical regulation, market regulation and policy advice to GDE separated from any operational business unit.
- Construction, Engineering and Technical Service Providers and associated functions moved into a separate business unit.

Step 2 – 2021 to 2025

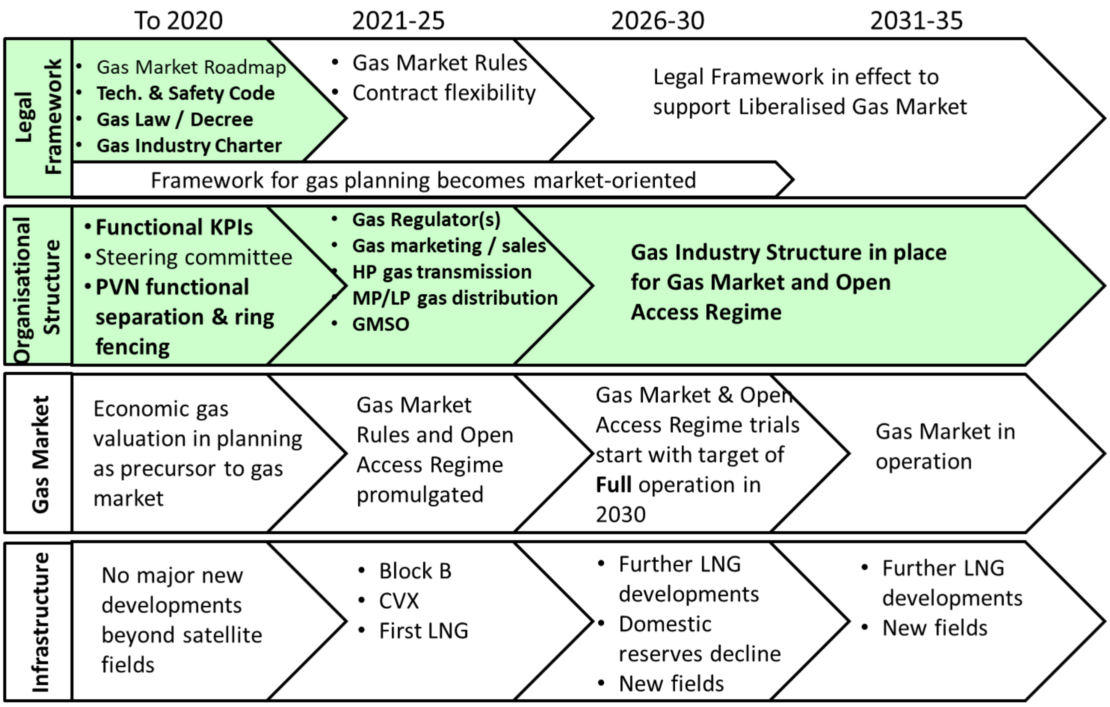
- Mid-stream and down-stream gas business functions including particularly PVGas, separated from the upstream oil and gas businesses and service providers.
- Establish an independent gas economic, technical and safety regulator.
- Gas system management and operations transferred to an independent agency.

Step 3 – post 2025

- Gas industry structure in place for gas market.
- Depending on government policies and financial considerations, the downstream businesses could be considered for divestment.

In Figure 28, as shaded, these transitional steps and timetable for the restructure of PVN are integrated into the Gas Liberalisation Roadmap.

Figure 28 Transitional Steps for PVN's Role in the Gas Market



PART D: ECONOMICS, PRICING AND PLANNING

8 Economic Valuation of Gas

8.1 The Role for Economic Valuation of Natural Gas in Viet Nam

In advance of a gas market existing in Viet Nam, a properly-applied economic gas valuation methodology will assist with determining the economic opportunity for gas exploration and development and opportunities for more economically efficient use of existing gas supplies. It can be used to assess the merits of importing LNG and the economically efficient place of gas (versus other fuels) in the future supply of energy to Viet Nam.

8.2 Economic Valuation of Gas

8.2.1 Principles for economic gas valuation

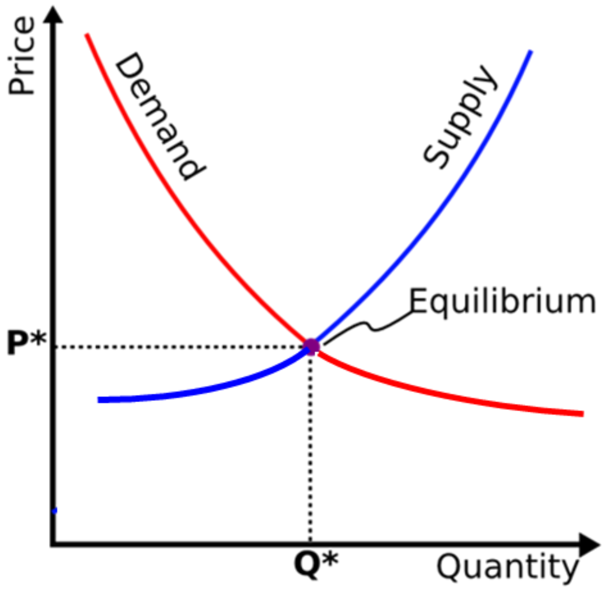
The economic value of gas can be illustrated by reference to the following basic supply/demand framework in Figure 29.

Figure 29 Gas Demand and Supply

a) ***Supply cost:*** *The delivered cost of gas, reflecting the capital and operating costs of production, transmission, storage and distribution.*

The supply cost increases with quantity as progressively costlier gas resources are required. The curve would likely 'flatten out' at the level of world LNG prices.

b) ***Demand value:*** *The market replacement net back value, where gas is valued based on the cost of alternative sources of energy.*



The high initial value is driven by the value of gas to end-users. The curve would tend to flatten out at the price at which high-volume substitutes for gas are available. Imported coal is an example.

Supply cost estimates require sufficient understanding of the supply chain costs – covering gas exploration, production and development costs, gas processing costs together with pipeline transportation costs, comprising capital and operating costs. A range of existing and potential gas supply sources exists. The economic cost of these sources includes currently undeveloped domestic gas production sources and the cost of LNG imports[27]. Together, these create a forward-looking projected gas cost stack which in turn defines the gas supply curve.

Low-cost gas supplies appear to have been developed first, as would be expected, and so current gas supplies are relatively low cost. Future gas supplies will inevitably be at higher economic costs and both domestic gas development costs and long-term LNG import costs inevitably have a range of uncertainty.

Importantly, the **e**conomic value of existing gas can and should be derived from the same forward-looking economic factors as the value of new gas supplies; that is, it is as shown by the 'equilibrium' price point in a basic supply/demand economic framework. This perspective may lead to a reassessment of existing gas uses.

The demand-based netback approach reveals the value of gas in different sectors of the economy, with the gas value being based on the first-choice alternative fuel available. The biggest gas user in Viet Nam is power generation and Viet Nam's Power Development Plan is for continuing high growth in power demand. Power projects provide the scale and investment security that is needed to underpin the development of Viet Nam's domestic gas resources and any LNG terminal facilities and major pipelines. From Viet Nam's energy plans, industrial and commercial gas consumption will not provide this scale and security.

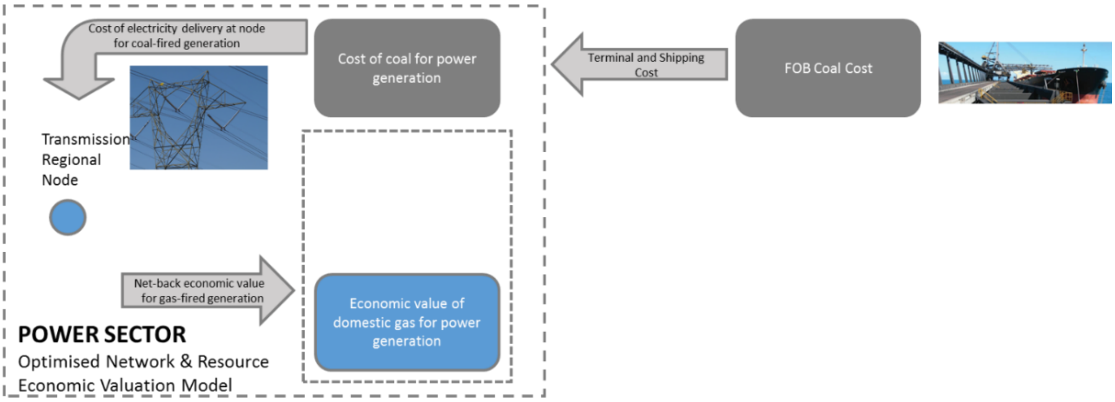
While Viet Nam's power plans include further development of renewables, current plans are that Viet Nam will need to supplement its domestic coal reserves with coal imports to meet projections for future power generation development. As an internationally traded commodity, it is reasonable to assume that significant and sufficient quantities of coal are available to supply Viet Nam's energy needs, to the extent that this is economic and in line with environmental or other relevant policies. Therefore, the economic value of gas can reasonably be defined by its ability to displace the planned significant increases in Viet Nam's coal requirements.

8.2.2 Applying an economic net-back gas valuation methodology

With power generation being the dominant use of gas in Viet Nam, and coal the baseline fuel source, the economic value of gas can be defined as the value which makes a unit of electricity generated by a gas-fired power plant economic against a unit of electricity generated by a coal-fired power plant. A reasonable first-pass estimate of the economic value of gas for the power sector is therefore calculated to be a net-backed value, derived from the cost of delivering a unit of power from coal-fired generation less the cost of delivering gas-fired generation as shown in Figure 30.

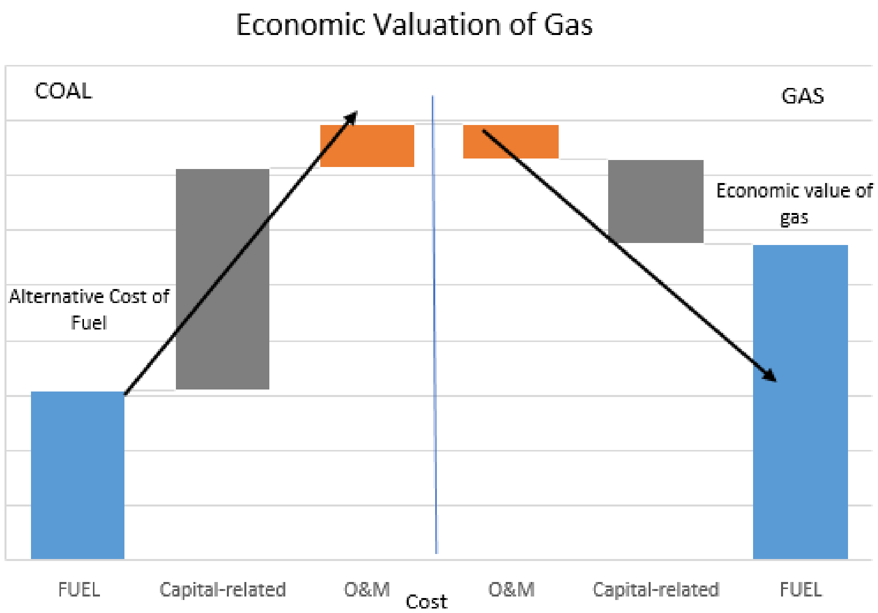
[27] These can be assumed to be based on forward international prices together with terminal and onshore pipeline capital and operating costs

Figure 30 Net back value methodology for the gas fired generation based on imported coal – net back value at the gas fired power station



This net-back calculation in its simplest form[28] is demonstrated in Figure 31. The gas value is the coal capital cost amortisation plus the coal operating and maintenance cost plus the international coal fuel costs, less the cost of gas operating and maintenance and capital expenditure amortisation. It represents the gas value required at the bus bar[29] for an equivalent coal base load power project.

Figure 31 Representation of net economic value of gas delivered in electricity network

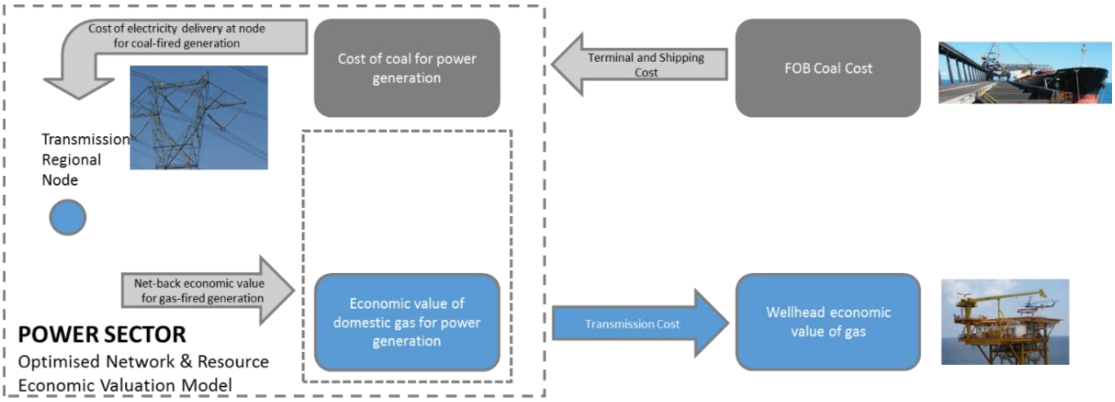


[28] Without taking into locational factors of the gas resource and alternative coal supplies and exogenous factors.
[29] The common network point (node) at which power is made available from the power plant including delivered cost and all direct and indirect costs of generation. Without adjustment, this assumes the transmission loss factor and incremental development cost of the transmission network to the connection node is equal for the coal and gas projects. In real-life application for specific projects, each of these factors would need to be included in an optimised Network & Resource Valuation Model for the power sector.

8.2.3 Assessment of a wellhead value

The assessment provides an unadjusted equivalent heating value-based economic value of gas at the power plant. The value of gas to the producer at the well head, as shown in Figure 32 would be net of (i.e. less) upstream transmission cost from the well head to the power plant.

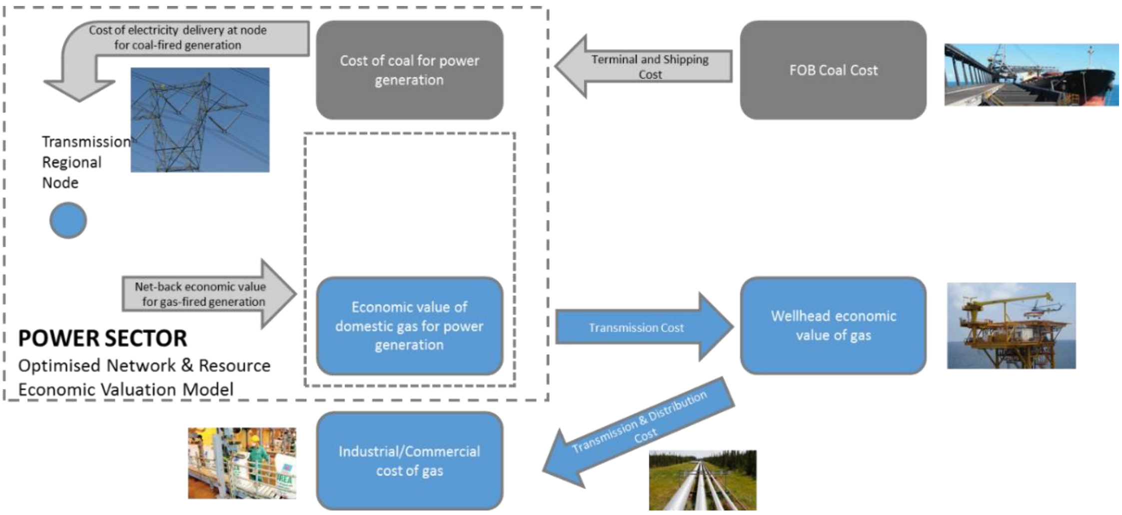
Figure 32 Net back value methodology for the gas fired generation based on imported coal - net back value at the well head



8.2.4 Application to industrial and commercial sectors

If gas is economically competitive in a bulk (or wholesale) energy market like power generation, then this is likely to underwrite competitive supply to the industrial and commercial gas distribution markets. The economically efficient cost of gas to industrial and commercial gas consumers as shown in Figure 33 would be the well head value plus transmission and distribution costs to those industrial and commercial users.

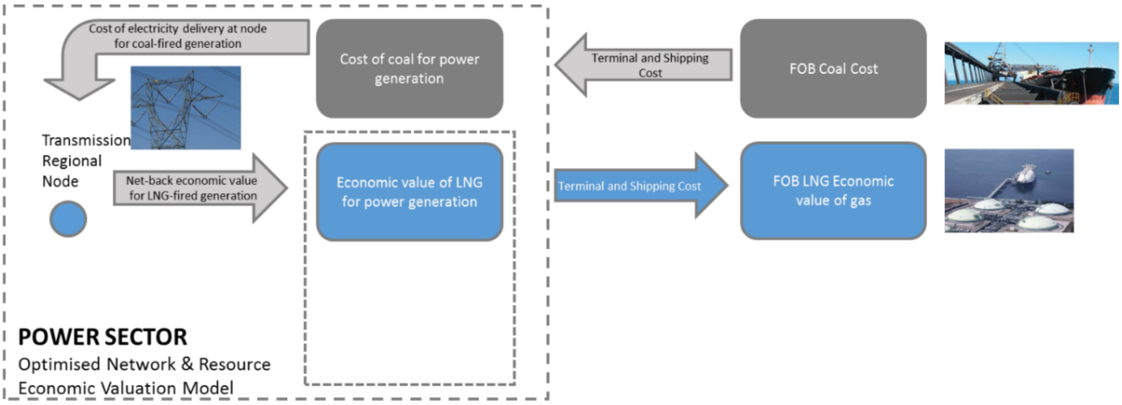
Figure 33 Net back value methodology for the gas fired generation based on imported coal - net back value for industrial and commercial sectors



8.2.5 Application to LNG

The economically efficient value of gas to LNG importers as shown in Figure 34 would be a FOB delivered price equivalent to the delivered economic value of gas at the power plant net of all (i.e. less) the upstream gas transmission and LNG terminal costs.

Figure 34 Net back value methodology for the gas fired generation based on imported coal - net back value for LNG



8.3 Economic Value of Gas: A Case Study Assessment

8.3.1 Background scenario assumptions

A demonstration assessment of the net-back gas cost methodology for both LNG and domestic gas reserves is provided in Appendix D. In this Section, the results of this analysis are summarised.

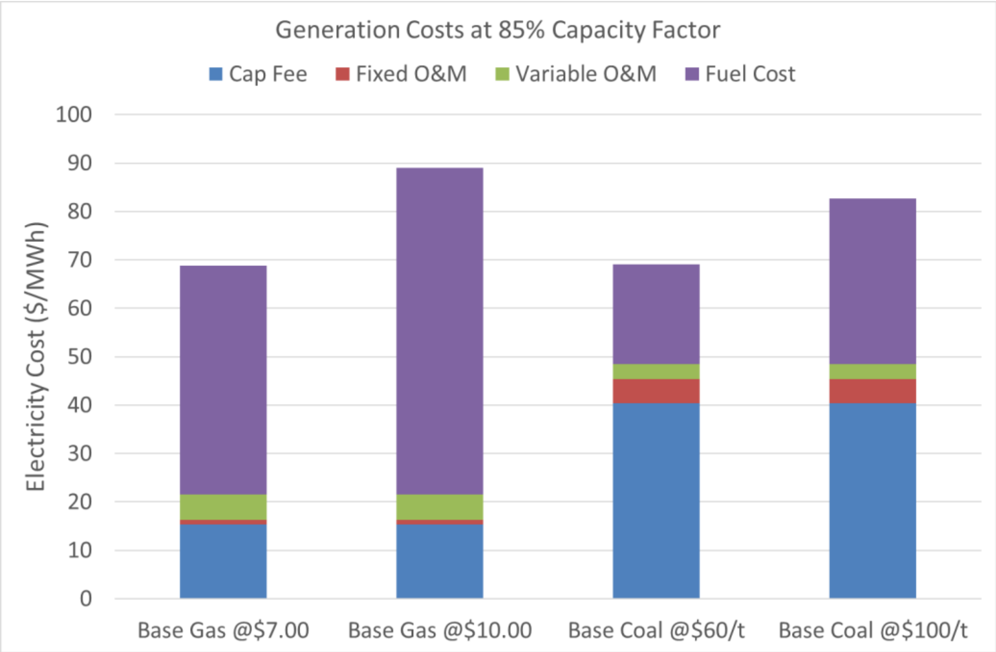
A cost model was utilised for coal ($US60/ton & $US100/ton) and gas ($US7/MMBtu and $US10/MMBtu) fuel supply and technology scenarios. International reference data was used for this analysis. A full resource assessment model would include adjustment for locality specific and proprietary technology, construction and O&M cost data applicable to a Viet Nam development.

To the extent that relevant government policies apply, it should also reflect differentiating factors such as carbon costs (whether explicitly priced or shadow priced), security loadings, and any fiscal loadings. These are not included in the ‘example’ assessment below, but are discussed in Section 8.4.3.

8.3.2 Base case model

An estimate of the total electricity cost for each gas and coal scenario was obtained using the base case assumptions in our economic model. For an 85% capacity factor scenario the amortised capital cost, fixed and variable operation and maintenance (O&M) costs, fuel and total costs are compared in Figure 35.

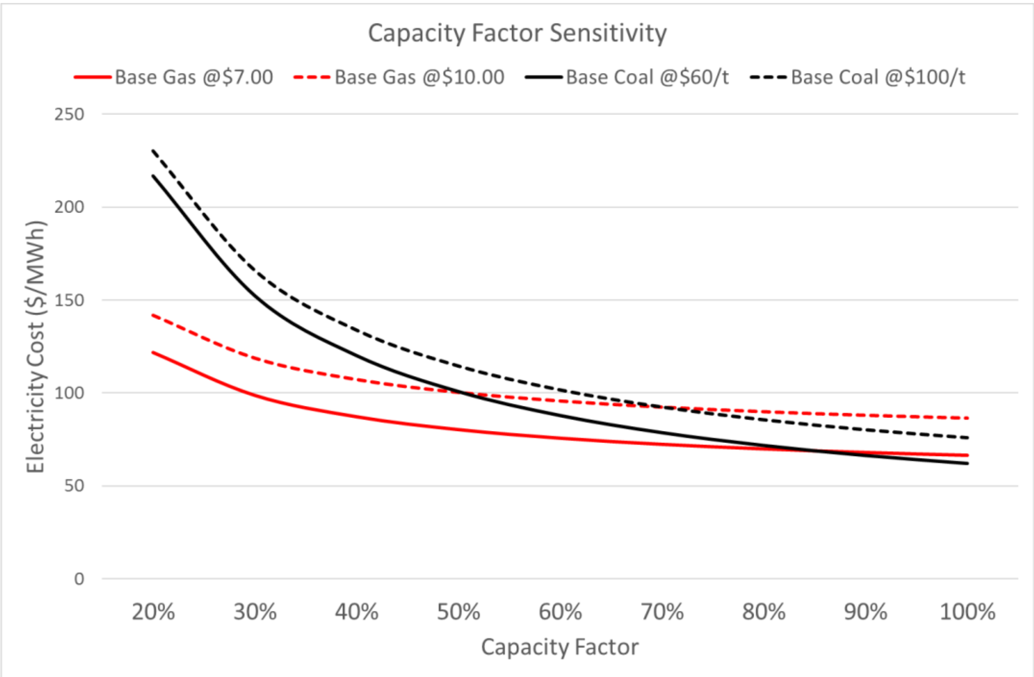
Figure 35 Base Case 85% CF - Total Electricity Cost for Coal and Gas Scenarios



8.3.3 Sensitivity to capacity factor

For a full range of capacity factor scenarios, the total cost of electricity supply is compared for the base case coal and gas developments in Figure 36.

Figure 36 Total Electricity Costs for Coal and Gas at Different Capacity Factors



8.3.4 Indicative gas value ranges

Figure 37 and Figure 38 examine the price sensitivity to gas value of electricity required for $60/ton and $100/ton coal developments at an 85% and 60% capacity factor.

- At 85% CF: Breakeven cost of gas is $7.04 at $60/t coal and $9.07 at $100/t coal
- At 60% CF: Breakeven cost of gas is $8.84 at $60/t coal and $10.87 at $100/t coal

In summary, for these scenarios, the economic value of gas would be around $7-$11/MMBtu delivered at the power station gate without any externalities or policy-based adjustments. The value of gas to the producer at the well head is this value net of (i.e. less) upstream transmission cost from the well head to the power plant. The value of gas to LNG importers would be an FOB delivered price equivalent to the delivered value of gas at the power plant net of (i.e. less) the upstream gas transmission and LNG terminal costs.

Figure 37 Sensitivity of Economic Value of Gas at 85% capacity factor

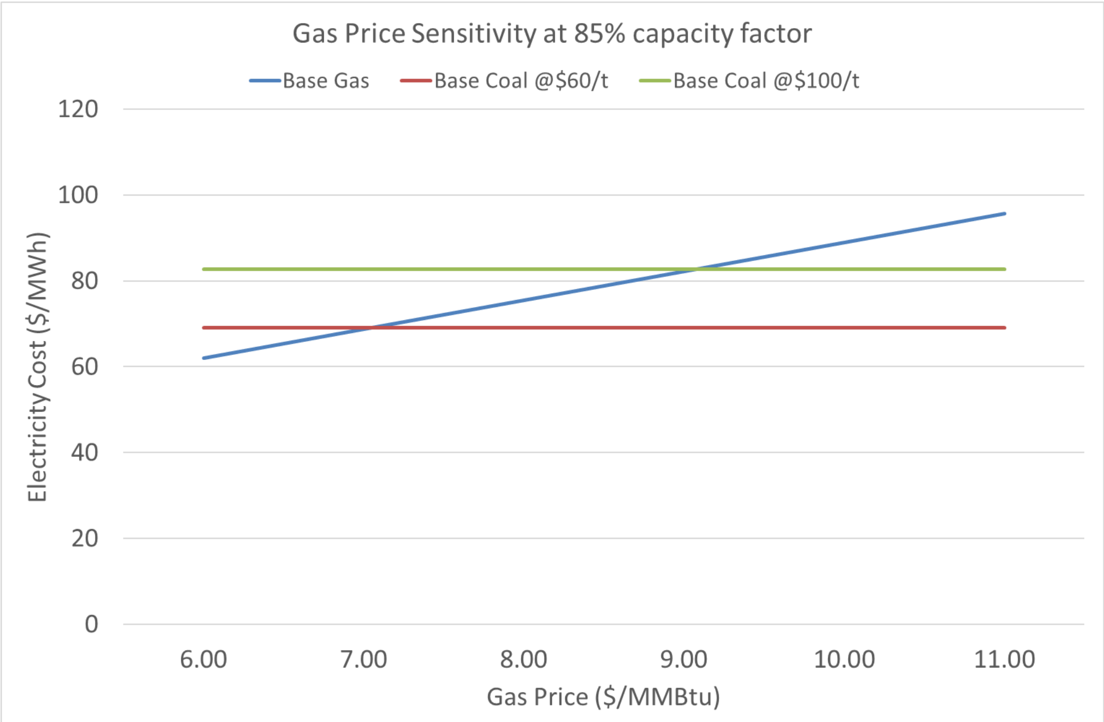
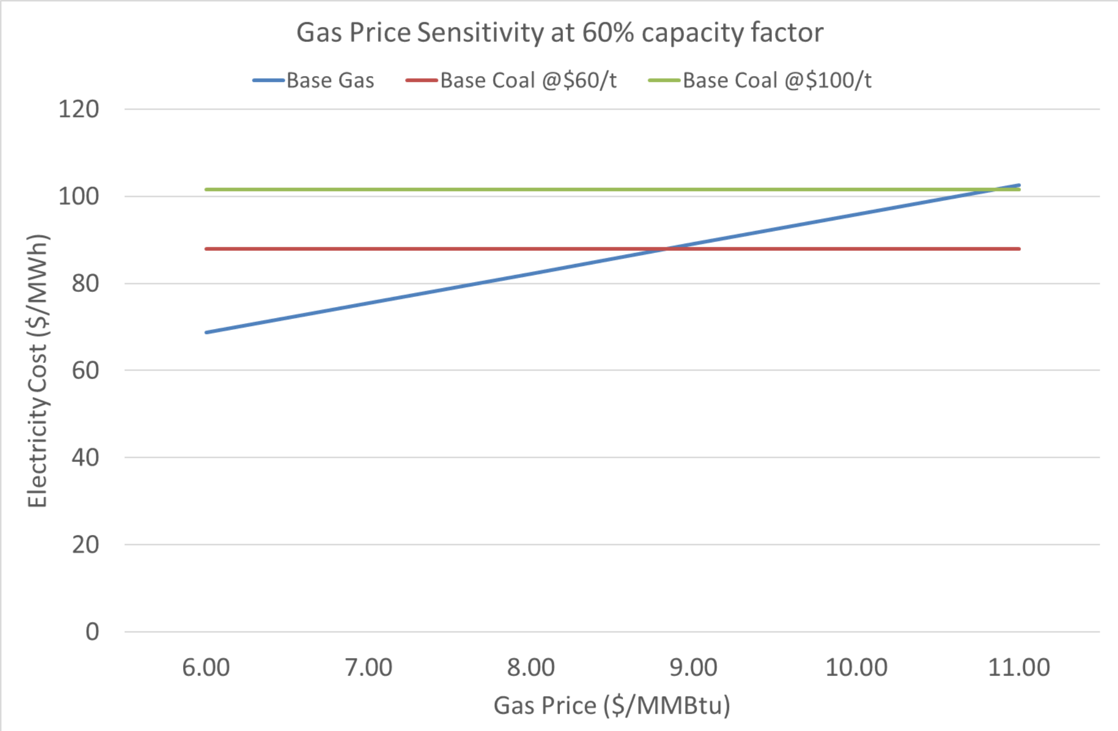


Figure 38 Sensitivity of Economic Value of Gas at 60% capacity factor



8.4 Implementation of Economic Assessment of Gas Value

8.4.1 Economic valuation methodology

In the absence of market pricing, resource development assessment and project planning will be reliant on an economic valuation methodology that is reliable, transparent and consistently applied. Confidence and trust in the valuation framework will require the following measures to be implemented:

- **Approved valuation methodology** – The valuation methodology and its role in resource development assessment, project planning and resource allocation decisions should be recognised and approved by the relevant policy entity and applied consistently in the Gas Master Plan.
- **Transparent published framework –** The economic gas costing framework and methodology should be a published reference document with a guideline and case study presentation.
- **Reference sources of cost data and information –** As part of resource and energy market planning, reference sources of cost data and planning information should be periodically reviewed and published. The cost data and information should be available in formats for input for network and planning model evaluation**.**
- **Checklist of investment criteria –** Investment criteria necessary to be addressed for project assessment and approval should be identified in the form of a checklist. Milestones, decision gates and timing may be part of this criteria assessment.

8.4.2 Endogenous factors in economic gas costing

The economic costing of gas is performing the function that a market might otherwise perform. In so doing, it must apply without bias the policies affecting all fuel, technology, environmental and geographic choices. This will have regard to:

- **Locational factors –** The optimum location of a gas power plant and a coal power plant is not likely to be same. An optimised network and an economic valuation model, would compare one or more regional power developments to deliver an economic valuation of gas at a transmission regional node for competing resource and power development options.
- **Plant types –** It is reasonable that gas, LNG and coal are all required to meet equivalent environmental standards and plant performance. Capex requirements should, to the extent possible, address all technical and performance requirements. There can be considerable differences in the value of different types of plant (peak/mid/base) at different locations, given transmission thermal constraint implications and system security / reserve margin considerations.
- **All incremental development and production costs –** All incremental costs and supply options netted back to a regional node must be addressed (including specific pipeline, transmission and coal infrastructure requirements). The gas and alternative fuel reference plant assessments should include all incremental costs including at-the-gate and terminal delivery, fuel management and storage.
- **Project timing, economic life of plant, residual value and economies of scale** – Modelling techniques are required to ensure project assumptions do not distort analysis. While economic gas values may be assessed and for convenience compared on a $/MMBtu basis, full economic value modelling is required to confirm assessments on a net present value basis.

8.4.3 Exogenous factors to economic costing of gas

A minimum "lower bound" economic value of gas is the unadjusted heating value of gas assessed for a specific project development and resource plan. An upper bound value of gas will consider externalities related to wider policy considerations and targeted fiscal reallocation specific to the needs and circumstances of Viet Nam.

The following exogenous factors may need to be considered in determining the upper bound economic value of gas[30]:

- **Emission and emergent technology policies** – We understand that Viet Nam currently does not have a formal carbon pricing policy. The development of gas resources may have different emission performance. Shadow pricing can be used to compare environmental performance and ensure that economic planning is also consistent with Viet Nam's Greenhouse Gas (GHG) policies. As a guideline, a carbon shadow cost[31] of $US15.0/tonne

[30] For illustrative purposes, the World Bank 2010 approach to such an adjustment is provided in Appendix C.

[31] ACIL Report to AEMO, Emission Factors Assumptions Update 10 May 2016 – gas 51.53kgCO2-e/GJ; and coal 90.23kgCO2-e/GJ.

has the effect of increasing the economic value of gas (relative to coal) by around $US0.9/MMBtu.

- **Fiscal Adjustments** – While strictly a 'transfer cost', rather than an economic cost, fiscal implications of different options should form part of a well-rounded economic assessment. Fiscal revenue benefits apply for domestic gas development in relationship to government ownership in developments, royalties, income tax and PSC terms. These may permit a higher economic value of gas at the cost of transferring or re-distributing this economic value. Selective adjustment to the government take on developments may target bringing the resource within the economic threshold. Such adjustments require specific policy consideration of the impacts before adjustments are applied.
- **Balance of trade adjustments –** Current Viet Nam energy projections require significant importation of coal. Such imposts should provide balance of trade benefits for the development of domestic gas.
- **Project Security and risk** – Whether or not applied as a cost adjustment, relative security benefits should come into an economic assessment. The financing of coal projects or addressing project risks may impose a higher cost of capital. These are subject to international banking practices and country specific environmental policies. Security requirements on the storage of gas, coal and LNG may also differ.
- **Competition benefits –** The introduction of a new fuel source such as LNG that is internationally traded in significant quantities, improves the level of competition for the supply of energy to Viet Nam. The additional negotiating leverage it provides is likely to lead to lower costs for other energy sources.

8.5 The application of economic valuation of gas in Viet Nam now and its future role in a liberalised market

Economic valuation of gas is required until there is a gas market in place. A gas market would eventually replace the need for economic costing of gas. However, market pricing of gas when progressed in Viet Nam may be limited to regional reference nodes accessible to multiple producers and where users are located. Until more domestic gas resources and LNG infrastructure are developed, and competition is increased through wider pipeline interconnection, the economic valuation of gas will continue to have a role for resource development and project planning, input to regional gas pricing, and wider policy assessment. This includes guidance and assessment on:

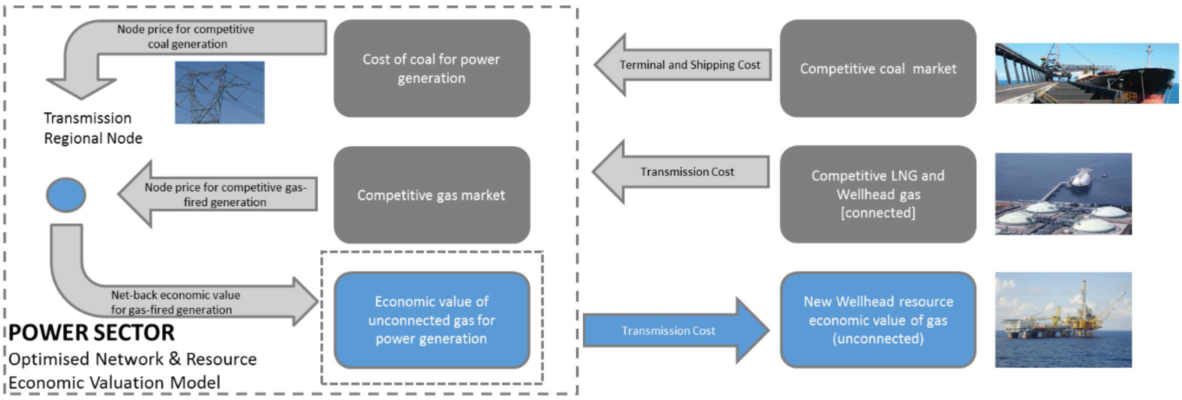
- long-term domestic gas development and LNG supply strategy and infrastructure development;
- long-term generation planning and development strategy;
- allocation and costing of gas between sectors;
- measure and value of preferential supply to petrochemicals;
- electricity and gas tariff design;
- development and design of climate policy;
- cost and value of fuel diversification and security of supply; and
- potential changes to upstream gas fiscal terms.

New gas is inevitably more expensive to develop than existing gas. Without access to additional low priced legacy gas there is a need to move beyond the current cost-plus approach for progressing developments on a project-by-project basis.

The economic valuation of gas will underpin comparison and prioritisation of gas resource developments and network development (both gas and electricity). In the absence of market pricing, it will provide a reference point for assessing power project developments, an input to gas pricing policy for gas users and a benchmark for evaluating and comparing the application and impact of energy policy initiatives and energy market designs.

As a competitive market develops in Viet Nam, as shown in Figure 39**,** the valuation methodology will continue to be used to assess and value the benefit of new resource development, network interconnection, infrastructure development and supply to users not connected to competitive gas networks and hub.

Figure 39 Net back value methodology for gas fired generation based on imported coal – new wellhead resource unconnected to competitive hub



The economic valuation of gas will bring Viet Nam's planning and use of gas closer to the outcomes of a fully-fledged gas market. It is an input and baseline to policy analysis. It provides a bridge to open access and to a future market with wholesale competition and will lead to better efficiency and decision-making than using historical prices.

8.6 Summary and Transitional Steps

8.6.1 Summary

Gas planning and gas allocation currently reflects legacy decisions which are not always consistent with the economics of the Viet Nam gas sector. Applying an economic valuation framework will improve Viet Nam's gas planning and allocation decisions. This will lead to economic and consistent decisions on a range of matters of vital importance to Viet Nam's energy future, including fuel sourcing to meet rapidly growing electricity demand, use of gas in feedstocks such as fertiliser, development of domestic gas fields, import of LNG and the development of pipelines and other gas infrastructure.

An economic gas valuation framework needs to be developed taking proper account of endogenous costs and with prescribed mechanisms to take account of exogenous factors such as carbon, energy security, fiscal effects and competition effects. The methodology needs to be owned and administered by a body that has the need and the capability to ensure that it is correctly and consistently applied in gas sector decision-making.

The need for a centralised economic valuation framework will fall away as the gas market develops and becomes workably competitive.

8.6.2 Transition steps

The recommended transitional steps for implementing the economic valuation of gas in preparation and prior to a competitive gas market comprise the following steps

Step 1 – To 2020

Develop and approve economic valuation methodology:

- Transparent published framework and guidelines.
- Reference sources of cost data and information.
- Checklist of investment criteria including milestones, decision gates and timing.

Apply to integrated economic resource and project planning and resource allocation:

- Technology, environmental and geographic neutrality, taking into consideration: location, plant types, incremental costs, project timing, economic life and scale, among other issues.
- Exogenous factors addressed, including: emissions and emergent technology policies, fiscal adjustments, project security and risk, balance of trade impacts and the benefits of competition.

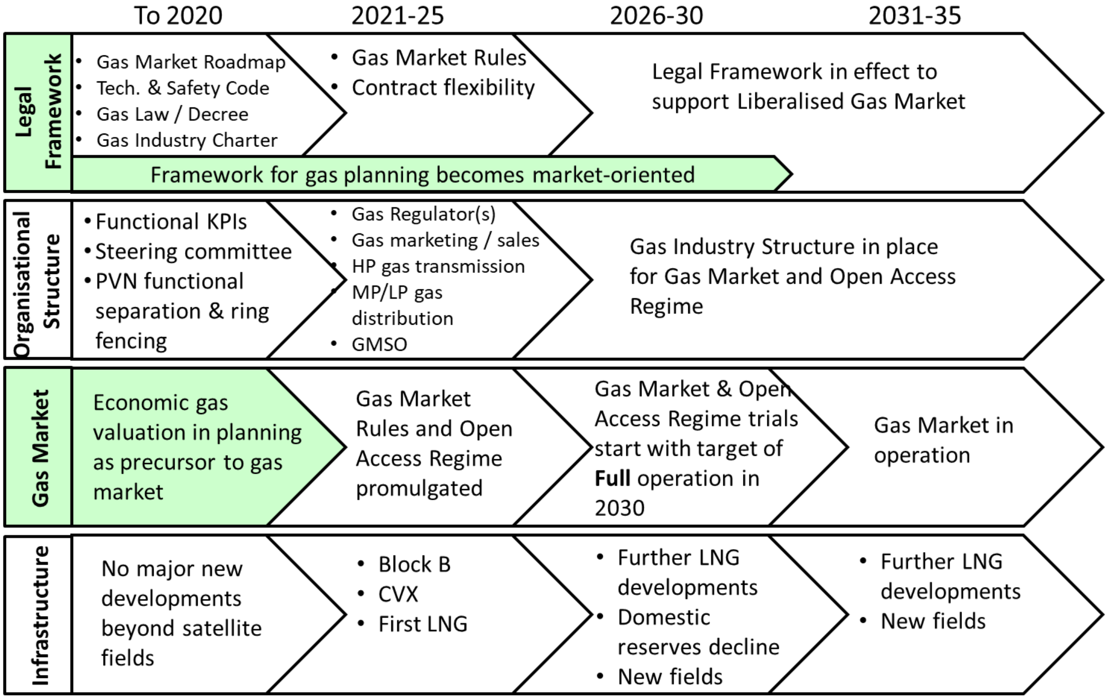
Step 2 – To 2020 and until competitive gas market exists

Apply economic gas valuation methodology into gas development planning:

- Compare and prioritise domestic gas resource and LNG development delivery.
- Assess options for gas pipeline and transmission network development.
- Input to gas valuation policy for generation projects, industrial, fertiliser and other gas users.
- Benchmarking and sand-pit assessment of energy policy initiatives and energy market design.

In Figure 40, as shaded, the economic costing of gas is integrated into the Gas Liberalisation Roadmap as an important input to planning and as a precursor to development of a gas market. The economic valuation of gas will continue to provide a resource development, project and policy evaluation framework until domestic gas resources and LNG infrastructure are developed, and competition is increased through wider pipeline and electricity interconnection.

Figure 40 Transitional Steps for Economic Valuation of Gas



9 Pricing and Contractual Mechanisms

9.1 Current Gas Pricing Approach in Viet Nam

9.1.1 Overview

Wholesale gas in Viet Nam is currently priced on the basis of project-by-project, bi-lateral negotiations between project proponents and PVN. There are some Prime Minister's Decisions setting gas prices and allocations for particular end uses or locations, but the derivation of those prices appears to have been the result of bi-lateral negotiations, involving end users as well as project proponents and PVN. In some cases, such as MOIT Directive No 6488, which specifies how gas is allocated between the fertiliser plant and power station at Phu My, the current regulations work against efficient outcomes that would be expected through the operation of a gas market[32].

Price negotiations for new projects are heavily influenced by historical very low gas prices which were possible because the development costs of those fields, particularly Nam Con Son, were very low by international standards. However, there is little apparent recognition that the higher development and production costs due to gas being discovered in deeper or non-contiguous reservoirs, being further offshore or being higher in impurities, inevitably results in higher prices for future developments.

Existing gas pricing appears also to be driven by a historical policy priority to achieve low electricity and fertiliser prices.

9.1.2 Gas take-or-pay gas prices

The prices for gas up to take-or-pay quantities for power plants in the South East region are set by negotiation between PVN/PVGas and the power plant owners.

9.1.3 Quantities beyond take-or-pay and for fertiliser plants

For gas delivered to power stations in the South West, quantities exceeding take-or-pay taken by power stations in the South East and South West, and for gas delivered to the Phu My fertiliser plant, a pricing formula is set out in the Office of the Government Directive 2175/VPCP-KTTH:

> *Gas price for user = Market gas price plus transportation and distribution charges.*
>
> where:
>
> - *The market gas price is the wellhead gas price calculated at 46% of the average Fuel Oil price of the Singapore market according to Platt's index (MFO).*
> - *Transportation and distribution charges are approved by the authorised agency, dependent on individual regions / pipelines.*

[32] MOIT Directive No 6488 specifies that nominated quantities of gas are delivered to Phu My fertiliser plant (PVCFC) first with the remainder of available supply being supplied to Phu My power plants. On occasions, this has led to PVCFC taking its contractual commitments despite PVCFC holding large stockpiles of fertiliser when some gas could have diverted to the Phu My power stations to optimise the power system.

9.1.4 Gas prices for industrial users

PVN sets annual gas pricing schemes based on the pricing of alternative fuels (FO, LPG) and market acceptance.

9.1.5 Gas prices for new developments and LNG

Based on discussions with participants in the Viet Nam gas industry, it appears that the pricing for gas from proposed gas developments continues to be driven by negotiation between PVN/PVGas (as the single buyer) and PVEP and its joint venture partners (as the gas producer).

The evaluation of new gas projects against alternatives appears to use historic gas prices as a benchmark rather than the costs of current alternative fuel options – coal, imported LNG, fuel oil or distillate[33]. There appears to be no consideration of externalities such as pollution/greenhouse costs, taxation or the impact on balance of payments of indigenous versus imported fuels in the evaluation of gas projects and the determination of the "economic price" for gas[34].

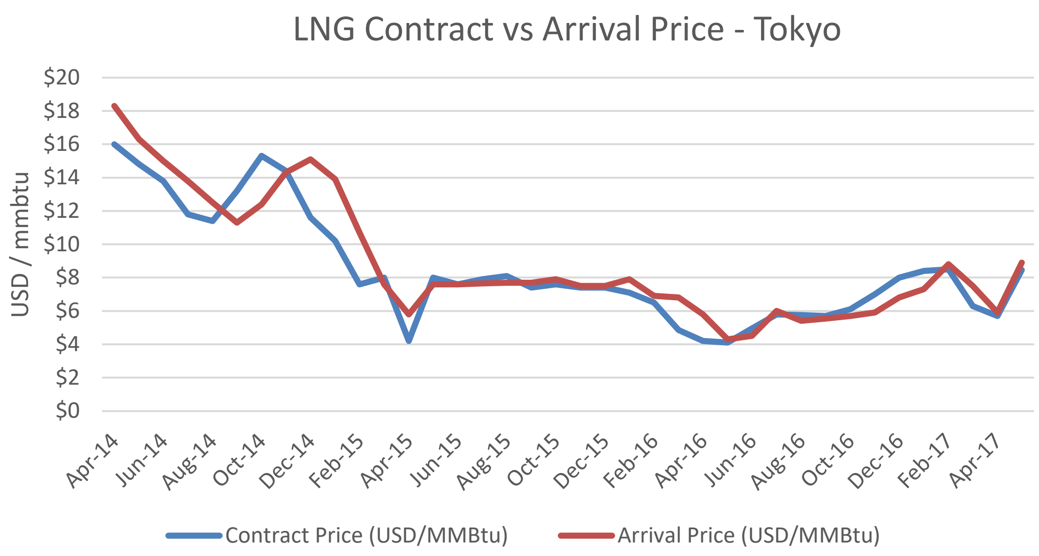
The expectation of the buyer that historical gas prices should be a benchmark has delayed development of both Block B and Cau Voi Xanh (Blue Whale), despite each having well identified technical challenges which result in much higher production costs than previous gas developments. Cau Voi Xanh was finally sanctioned in early 2017.

As a relatively small market, Viet Nam will be a price taker for LNG commodity in the international market. Accordingly, negotiations can only focus on the costs for development and operation of the re-gasification infrastructure. A project-specific approach, using historical prices as a benchmark is unlikely to be conducive to successful negotiations for proposed LNG imports.

Japan's Ministry of Economy, Trade and Industry has been publishing average spot LNG prices, delivered into Japan, for each month since March 2014[35]. Figure 41 shows how the LNG price has moved from a high of around USD18 per MMBtu in April 2014 to a low around USD4 in April 2015, followed by a 6-month period of relative stability around USD8 and then some volatility for the last 12 months. The spot LNG price has been higher than historical gas prices in Viet Nam for this entire period and for much of the period has been at multiples of the prices which Viet Nam has been enjoying. Using these prices as a benchmark, the cost of the LNG commodity, before adding in the cost for the re-gasification infrastructure, will exceed current prices in Viet Nam.

[33] We discuss this matter further in Section 8
[34] Again, this is discussed further in Section 8
[35] www.meti.go.jp/english/statistics/sho/slng

Figure 41 Spot vs Contract LNG Prices (USD) for Delivery into Tokyo Bay



A new approach to pricing gas, which is not based on historical benchmarks, will be required if Viet Nam is to commence imports of LNG in the foreseeable future and to enable development of new gas fields. It could appear to be attractive to introduce a market-based pricing mechanism for LNG and use it as the first step in market liberalisation. However, there are several factors which will require detailed study to determine if this approach is practical. The required level of assessment is beyond the scope of this report, but should be a key element of an implementation project for introduction of a gas market. The key issues to be addressed are:

- Timing, per the Gas Master Plan, of the introduction of LNG (2020/2021) and the liberalised gas market (post 2025);
- LNG would need to be integrated into the existing gas market as another supply source and not treated as a separate stand-alone energy supply option;
- Pricing of international LNG versus existing indigenous gas sources, without any reform, and the consequent impact on demand for LNG; and
- Potential customer demand for gas at international LNG pricing and the price elasticity of that demand.

9.2 Alternative Pricing Approaches

Studies conducted by the World Bank, Asian Development Bank and Viet Nam Government Agencies in recent years have identified a range of gas pricing methodologies including:

- Pricing against alternative fuels;
- Cost of service of gas production;
- Gas pooling;
- Capacity of the market (particularly power generators) to pay;

- Gas on gas competition;
- Import opportunity pricing; and
- Export opportunity pricing.

It is not the intention of this project to re-visit each of these approaches, but rather to draw on them to develop a roadmap for the development of a gas market which supports the economic development of Viet Nam.

The factors to be considered when evaluating alternative gas pricing methodologies for Viet Nam are as follows:

- At the supply side, the gas price needs to provide the appropriate financial incentives to gas developers to invest in exploration, development and production activities. This should lead to optimal investments in the upstream sector and should ensure that only those gas fields that are economically competitive in Viet Nam's main gas consuming sectors, are developed; and
- At the demand side, it needs to provide the right signals to investors to choose gas as the economic, lower-cost fuel when supply increments become available. This should lead to optimal investment in the consuming sectors, i.e. gas should only be used in those gas-consuming projects in which it is competitive with its alternative. An example, which we describe in Section 8, is coal as an alternative fuel to gas in the power generation sector. Other examples would include continued use of gas as a feedstock for fertiliser production versus other uses for the gas, and alternative sources for fertiliser.

Different customers may continue to pay different contractual prices for gas. However, in a functioning gas market with transparent information published by the market operator, customers, suppliers and any other party with contractual entitlements to gas will have the opportunity to trade according to 'market prices'. And gas planning, gas development, gas import and gas usage decisions will be more efficient once current and potential suppliers and users each face the same 'market prices'.

9.3 Current Regulatory and Contractual Constraints

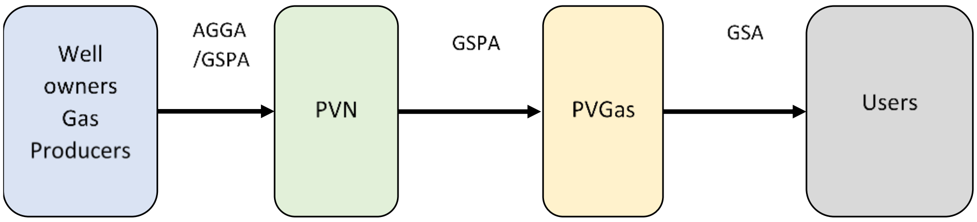
The existing gas supply agreements appear to be ambiguous on the rights of gas buyers to on-sell gas to third parties in that the contracts, apparently, neither expressly allow nor prohibit on-selling. For the Phu My complex, a Prime Minister's decision specifies the allocation of gas between the power station and the fertiliser plant, with no apparent scope for trading between those facilities. This Decision is used to interpret other arrangements to prohibit the on-sale of gas and results in inefficient allocation of gas on a daily basis. The consultants understand that, as a result of these contractual interpretations, power stations are curtailed on occasions while fertiliser plants receive their full allocation of gas in spite of there being a surplus of fertiliser in stockpiles.

The current arrangements and the expectations of low gas prices for power generation created by those arrangements tend to discourage investment in gas exploration and development and therefore work against some high level objectives for the sector such as growth and diversification of fuel sources for power generation.

The contracting approach reflects the current industry structure:

- Upstream:
  - Gas exploration and production activities are carried out through contractual arrangements between PVN / PVEP and foreign investors.
- Midstream:
  - Gas pipelines have been built under two schemes: 100% self-investment by PVN/PVGas or BCC (joint venture between PVN/PVGas and foreign investors). By end of 2013, Nam Con Son was the only pipeline system that was invested through the BCC format with PVGas contributing 51% of the total asset value.
  - In regard to the commercial framework, PVN is the sole buyer of gas from the well owners (excluding some contracts signed between PVGas and well owners before 10 September 2012). Gas purchased by PVN is consequently sold to PVGas and / or direct gas users. PVGas also has the role of managing and operating the gas pipeline system and gas processing facility. PVN gas purchase and sale contracts are normally back to back agreements (for power producers and fertilisers). The current commercial frameworks are[36]:
    - **Contract arrangement 1**: Illustrated in Figure 42;
    - **Contract arrangement 2**: Contracts between PVN and PVGas are to cover gas collection and transportation services and / or other contractual auxiliary services to be done by PVGas on behalf of PVN.; which is illustrated in Figure 43; or
    - **Contract arrangement 3**: This scheme applies for those contracts previously signed between PVGas and well owners. PVN, nevertheless, still approves the gas price for each user under GSA. The arrangement is illustrated in Figure 44;
- Downstream:
  - PVN/PVGas sell gas to downstream users in a prioritising order of: power producers, fertilisers, PVN prioritised projects using gas and other users (low pressure gas distributors, CNG suppliers, etc).

Figure 42 Contracting Arrangement 1



[36] Viet Nam Gas Industry Models provided by GDE

Figure 43 Contracting Arrangement 2

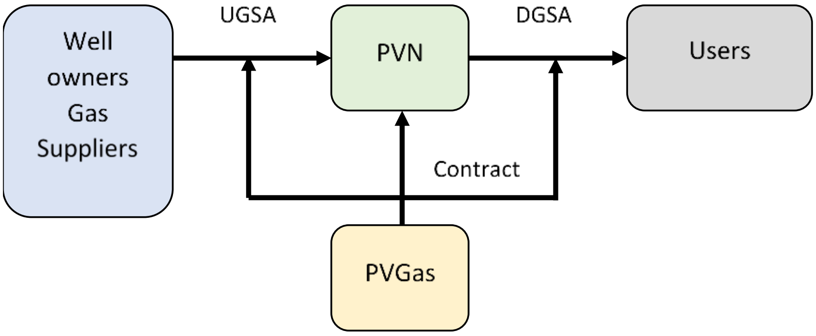
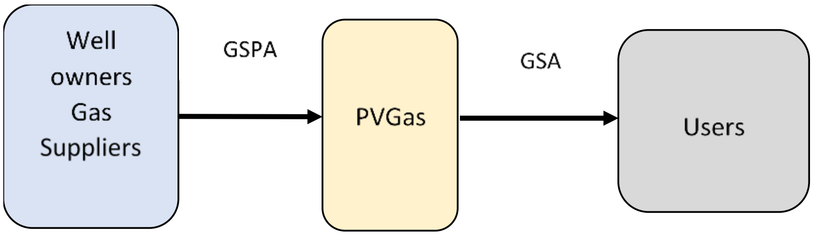


Figure 44 Contracting Arrangement 3



The consultants understand that the development of Cau Voi Xanh has been approved on the basis of an integrated project with the field operator, ExxonMobil, being responsible for the full supply chain from the gas field to the power station.

The current contracts and regulations do not provide for some of the key terms and conditions required to improve transparency, and ultimately liquidity, particularly where significant take or pay commitments are imposed on the buyer. Some of the features of contracts which can provide customers with the ability to manage their obligations include:

- Access to storage, either in the producing field (banking) or LNG import terminal, in the pipeline network or in dedicated storage facilities;
- Rights to trade gas to third parties on terms relevant to the trade and independent of the initial sale terms, including pricing; and
- Open access to mid-stream and down-stream facilities. Government has a critical role in implementing a regulatory regime to facilitate open access to gas pipeline infrastructure, and potentially gas processing facilities. This access is critical to the rights of gas buyers to utilise their rights to store and trade their surplus gas and to encourage the development of smaller resources.

9.4 Issues to be addressed for Gas Market Development

9.4.1 Transparency and information

PVN collects significant volumes of operational data which could be useful for the development of a gas market. However, that data is currently closely held within PVN.

A market requires information to be available to participants in order to function. An independent market operator is best placed to provide the information, generally through a bulletin board accessible only to registered market participants. The market operator must have access to all operational data and most commercial data (except pricing) to operate the market and can publish that data in aggregated form to protect the commercial interests of market participants. The market participants can then identify opportunities to trade between themselves.

The establishment of a bulletin board to publish market data will require the system operation functions of PVN to be ring-fenced from commercial functions, or to be transferred to an independent market and system operator.

The introduction of LNG imports to Viet Nam will provide a further benchmark on gas prices, as the LNG price will be determined by international factors and not local conditions or policies.

9.4.2 Gas market analysis

A market analysis of potential gas users, beyond the current user classes, should be a priority to determine the possible size of the gas market, and the price expectations (and elasticity) of those customers. While this type of detailed analysis is beyond the scope of this assignment, it is suggested that the energy consuming industries along the route of the Nam Con Son pipeline system through Vung Tau and the adjacent regions would be an appropriate place to start such a study. Such a customer study would inform the amendments required to directives and contracts to broaden the potential customer base, with some customers likely to be ready to switch from coal or oil to gas in the near term.

9.4.3 Existing contracts

Negotiations should be commenced with existing gas sellers and buyers to introduce flexibility into current contracts to allow gas trading between buyers and for buyers to store gas and to access “spot” gas from sellers. Flexibility will not reduce overall gas demand, but will open opportunities for incremental gas sales as buyers will be better able to access additional gas for short term requirements. These negotiations should be viewed as an opportunity, and not a threat, by both sellers and buyers. However, there is a risk that any party could try to open contractual terms which are working, but which the party finds inconvenient, leading to potentially protracted and adversarial negotiations.

9.4.4 Pricing to facilitate efficient operations

The gas supply system is operated on the basis of satisfying day-ahead nominations, with no intra-day signals of surpluses or deficits for any gas customer. The system control centre appears to set the system to deliver nominations for the day and only intervenes in the event of a significant incident impacting on operations. Co-ordination between the gas system operators and the electricity National Load Dispatch Centre is effective in setting daily requirements and in responding to incidents.

This mode of operation does not provide any pricing signals to the market of incremental demand or available incremental supply which could be satisfied by short term arrangements between buyers or between buyers and suppliers. A process which does not constrain buyers to nominating their precise requirements, but also allows for trading between buyers and short-term relocation of delivery points would provide some information which would support the development of a market.

9.4.5 Open access tariff requirements for a liberalised gas market

A transition to a liberalised market will result in disaggregation of the current end-to-end supply arrangements, as described in section 6, with specific entities operating the relevant disaggregated components of the current gas sector[37]. Regulators can then require operators to submit their costs for approval in tariffs. Through the approval process, the regulators must have access to resources, including expert consultants, to challenge the operators' claims and to disallow costs which are unreasonable when compared to industry benchmarks or for which there is inadequate justification.

While not all pipeline tariffs need to be subject to regulatory approval, all must be at least subject to regulatory oversight, with regulatory tariffs providing some benchmarks on reasonable costs. The regulator or customers must have the right to apply for a pipeline to be subject to regulation if they believe that the pipeline operator is not offering access on fair terms.

As with the multiple options for gas pricing, there are numerous options for setting pipeline tariffs. The most common tariff approaches include a capacity charge, which is paid every day to reserve the buyer's right to use its contracted capacity and which is generally structured to recover the fixed costs of providing the pipeline, and a throughput charge which is based on the actual gas delivered on a day and which recovers the pipeline's variable costs. The three most common approaches to setting each of these elements are:

- "Postage stamp" tariffs, whereby every user pays the same charge, are usually applied on pipelines where most of the demand is located at the end of the pipeline, such that it would not have been built for loads part way along the pipeline;
- Distance based tariffs are used where load is spread along the pipeline; and
- Zonal tariffs are used where there are a number of significant load centres along the pipeline. They are particularly useful where users at different locations require different facilities, such as compression, for their demand to be met, or where the size of the pipeline reduces over its length as demand is satisfied. The pipeline is effectively segregated into zones defined by compressor stations and/or changes in pipe size.

[37] As is discussed in sections 4 and 5, these could be different corporate entities, or they could be ring-fenced entities within PVN.

Distance based or zonal tariffs can also be mandated by the Government or regulators to incentivise investment in gas consuming industry in particular locations.

Template contracts for the principal mid-stream and down-stream services likely to be required to support the market – gas transportation, connection to pipelines, gas trading, gas storage – should be developed along with the third party access regime for infrastructure to provide some clarity for new entrants.

9.4.6 Market interconnection

Some limited commercial interconnection can be achieved through secondary market trading through the electricity and/or fertiliser markets. Such trading could be introduced once the gas market is functioning, without physical interconnection of pipeline systems. A properly functioning electricity market will introduce competition between gas sources to produce power into the common electricity market, regardless of the gas sources not being directly interconnected. The competitive power market will provide both long-term signals for gas field and gas import and other infrastructure development, and also short-term price signals for hour-by-hour dispatch,

Ultimately, physical interconnection between the South East and South West pipeline systems would, if economic, provide all buyers and sellers in each region access to their counterparts in the other region. This would increase options for trading, especially when LNG is introduced into the South East and is integrated into the pipeline network. The practicality of building interconnecting pipelines is beyond the scope of this report, however at least feasibility studies for pipeline interconnection should be undertaken as part of the market transition.

9.5 Summary and Transitional Steps

9.5.1 Summary

A transition to a liberalised market will result in disaggregation of the current end-to-end supply arrangements. At the supply side, the gas price needs to provide incentives to gas developers to invest in exploration, development and production activities. At the demand side, it needs to provide the signals to investors to choose gas as the economic, lower-cost fuel when supply increments become available.

A gas market will be based on more flexible gas pricing and contract mechanisms, and the progression of industry structure, market information, rules and regulations to support the financial market exchange of gas volumes and the optimisation of transport and gas market operations.

9.5.2 Transitional steps

The recommended transition of gas pricing and contract mechanisms in preparation for a gas market comprise the following steps:

Step 1 - to 2020

- Economic gas valuation in planning as precursor to a gas market.

Step 2- 2021 to 2025

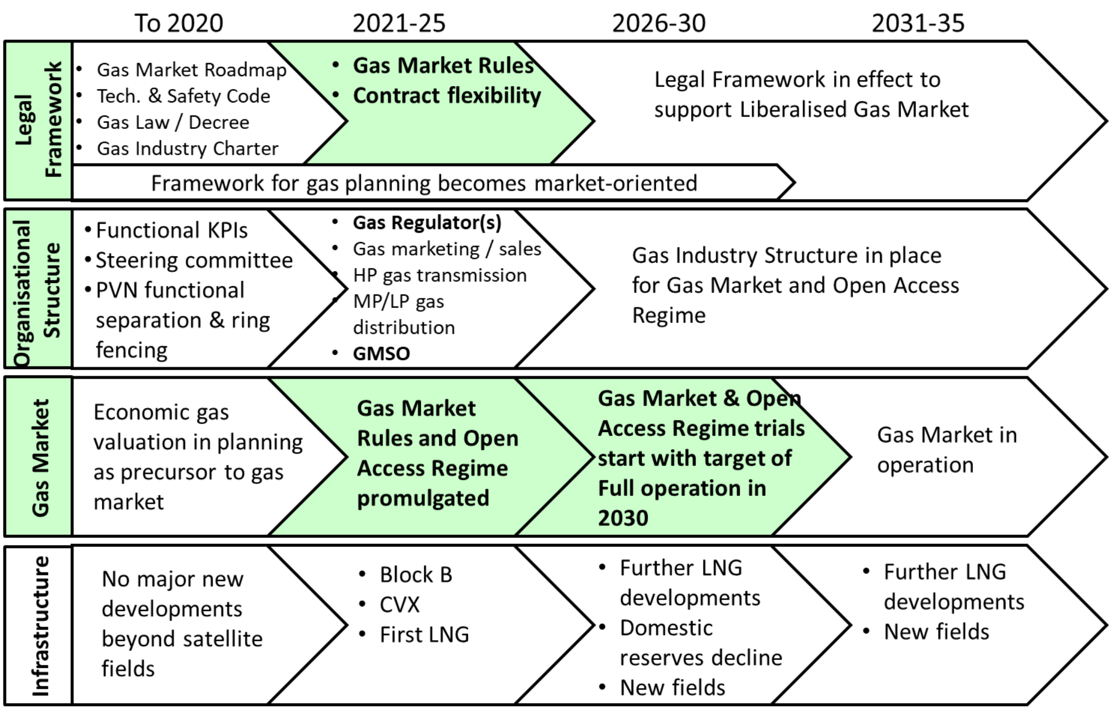
- Establish an independent gas economic and technical regulation
- Gas market rules and open access tariff regime promulgated
- The establishment of a bulletin board to publish market data
- Remove restrictions and permit flexibility in gas contracts
- Gas management and system operations transferred to an independent agency

Step 3 – post 2025

- Gas industry structure in place for gas market
- Introduction and trial of gas trading

In Figure 45, as shaded, these transitional steps and timetable for the restructure of PVN are integrated into the Gas Liberalisation Roadmap.

Figure 45 Transitional Steps for Pricing and Contractual Mechanisms



10 Gas Industry Planning

10.1 Gas Master Plan

The Gas Master Plan (GMP) was prepared and submitted to MOIT by PVN in 2016 and was prepared under Prime Minister Directive No. 296/TB-VPCP dated 27 July 2014. The Gas Master Plan (GMP) was approved by the Prime Minister on 16 January 2017 (Decision 60/QD-TTg) "General plan for Viet Nam's gas industry to 2025 with vision to 2035".

The purpose of the GMP is to provide an overarching sequence of developments for Viet Nam's gas sector from the present to year 2025, with an outlook to 2035. It is to be consistent with the industry's current situation, global outlook for natural gas and to provide a basis for implementation of investment programs in regards to gas production, supply and gas sector governance.

10.1.1 Stated initiatives for the GMP

The main initiatives of the GMP are:

- Maximize domestic gas production from existing fields;
- Exploit supplies from offshore fields such as Ca Voi Xanh, Bao Vang and fields from Song Hong basin;
- Augment gas supply in the South East region to counteract declining production volumes;
- Plan and implement LNG imports;
- Consolidate gas transportation and distribution facilities in existing regions to support planned developments;
- Enhance coordination between PVN and EVN for more streamlined gas supply – demand market; and
- Develop an appropriate gas pricing policy with a consistent gas price roadmap to meet interests of the state, gas sector businesses and users.

The GMP sets out numerous infrastructure development options to support these directives, including the development of domestic reserves, importing LNG, development of onshore and offshore gas transport infrastructure and the development of gas processing plants.

10.1.2 GMP's sequencing of developments

The broad sequencing of the development options identified in the GMP is summarised in Figure 46 and Table 4. Broadly, the plans for Viet Nam's gas industry are based on the development of offshore fields from 2020, before putting in place appropriate onshore infrastructure to support those developments – in particular, to consolidate gas supplies in existing regions and augment them with supplies from the Central region. From 2021, Viet Nam also plans to supplement domestic gas with LNG imports. Further details of the development options identified in the GMP are listed in Appendix B.

Figure 46 Sequence of Developments Proposed in GMP

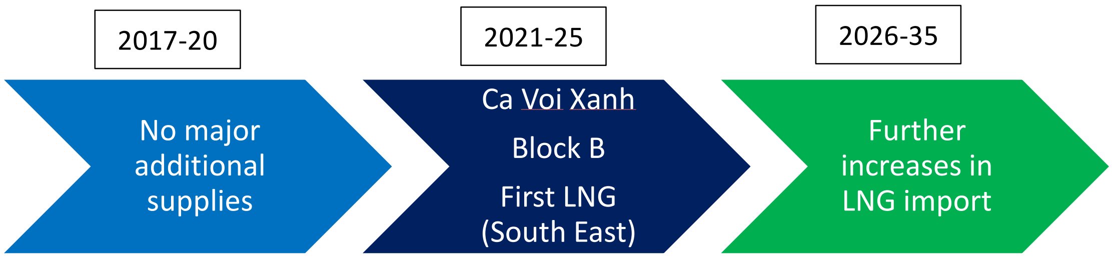


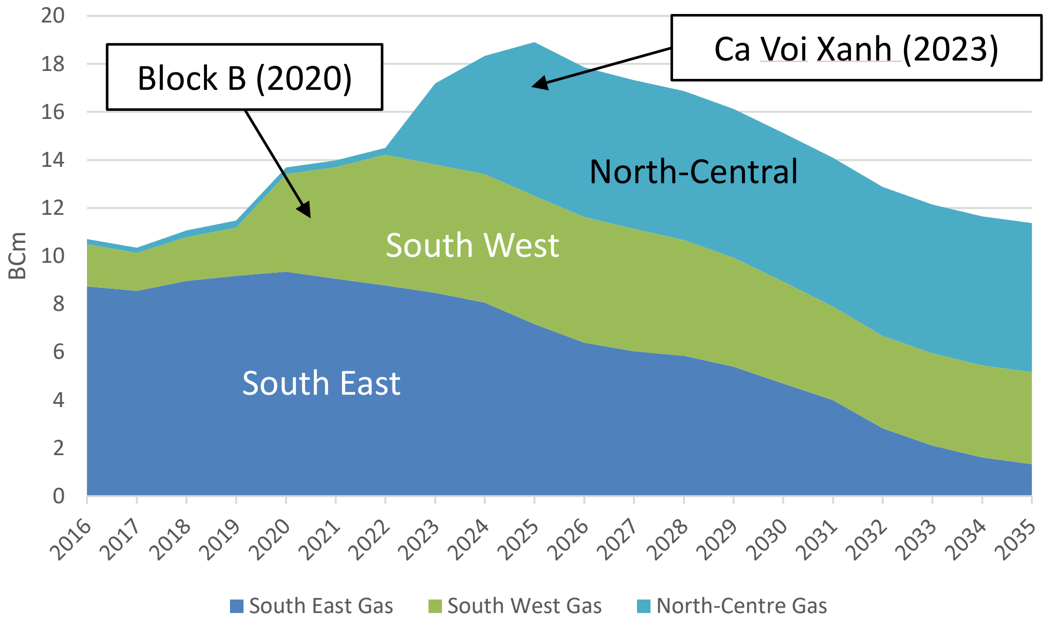
Table 4 Summary of GMP Development Sequence

Period	Key Developments
2016-20	• Gas supply in the South East: stable at 8-9 Bcm/year, meeting existing demand for natural gas in Viet Nam • Total domestic supply: 10-11 Bcm/year
2021-25	• South East region fully developed with total supply of 9.1-9.7 Bcm/year by 2024 • Ca Voi Xanh first gas in 2023, peaking at 6.2 Bcm / year from 2025 onward • Block B first gas in 2020 • Total domestic supply: 13-19 Bcm / year • First LNG import for the South East in 2020-2021. More imports will be followed for other regions, with total volume reaching 4 Bcm in 2025
2026-35	• Block B peaking at 3.84 Bcm/year in 2031 • Total domestic supply: 17-21 Bcm/year • LNG import increasing up to 10 Bcm/year

10.1.3 Domestic reserves supply outlook under the GMP

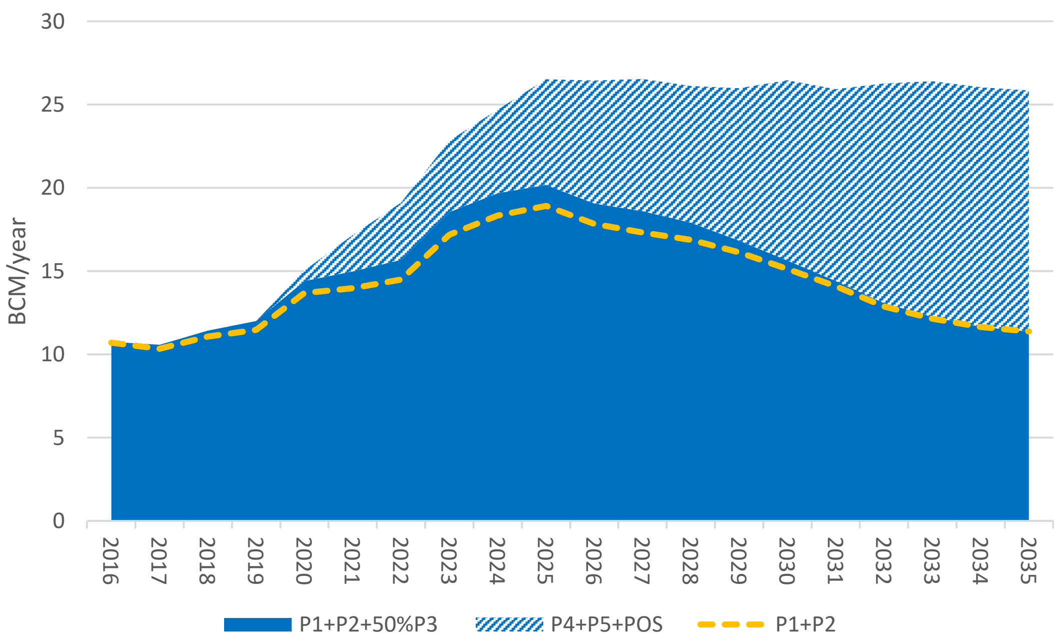
The specific sequence of offshore gas field developments in the GMP leads to the supply outlook for domestic fields as illustrated in Figure 47 for P1 and P2 reserves and in Figure 48 for P1+P2+50%.P3+P4+P5+POS. South East region supplies the Phu My complex, Ba Ria and the Nhon Trach CCGTs – there is clearly a steady decline in production from 2020 to 2035. The South West region has supplies increasing with Block B gas having first gas in 2020, which is a very optimistic projection of first gas. The South West gas reserves will supply gas to the Ca Mau Complex and the O Mon complex and potentially other CCGT development from 2020 with production levels projected to relatively constant from 2022 to 2027 before a general decline in production levels starts.

Figure 47 P1 + P2 Gas Supply Projection for Viet Nam's Domestic Reserves under the GMP



Source: Draft GMP

Figure 48 P1+P2+50%.P3+P4+P5+POS Supply Projection for Viet Nam's Domestic Reserves under the GMP



Source: Draft GMP

10.1.4 Downstream gas market development

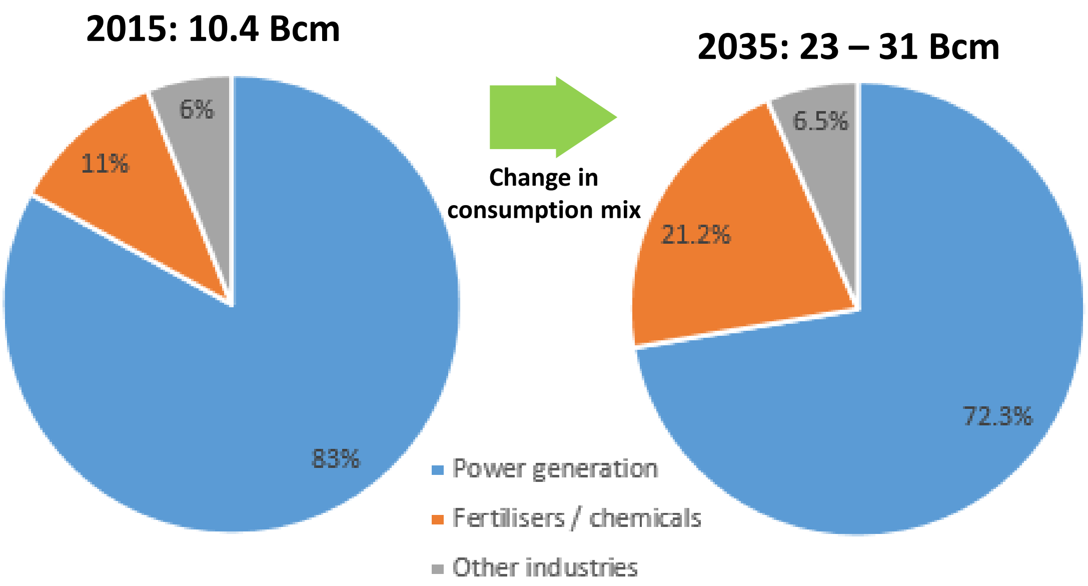
Table 5 summarises gas demand and projected sector growth as per the Draft GMP. Planning projections suggest an increased share of fertiliser related demand and continued growth in the power and industrial sectors. Pricing policy has been recognised as being critical to fuel supply competition and cost recovery for power sector development and to provide access to the competitive supply of gas for the industrial and fertiliser sectors.

Table 5 Summary of Gas Demand and Projected Sector Growth

	Gas Allocation (%)		Gas Demand (bcm/yr)		Change (bcm / yr)
	2015	2035	2015	2035	
Power	83.0%	72.3%	8.63	15.18	6.55
Fertiliser	11.0%	21.2%	1.14	4.45	3.31
Industrial	6.0%	6.5%	0.62	1.37	0.74
Total	**100.0%**	**100.0%**	**10.39**	**21.00**	**10.60**

Source: Draft GMP

Figure 49 Downstream Gas Market Development under the GMP

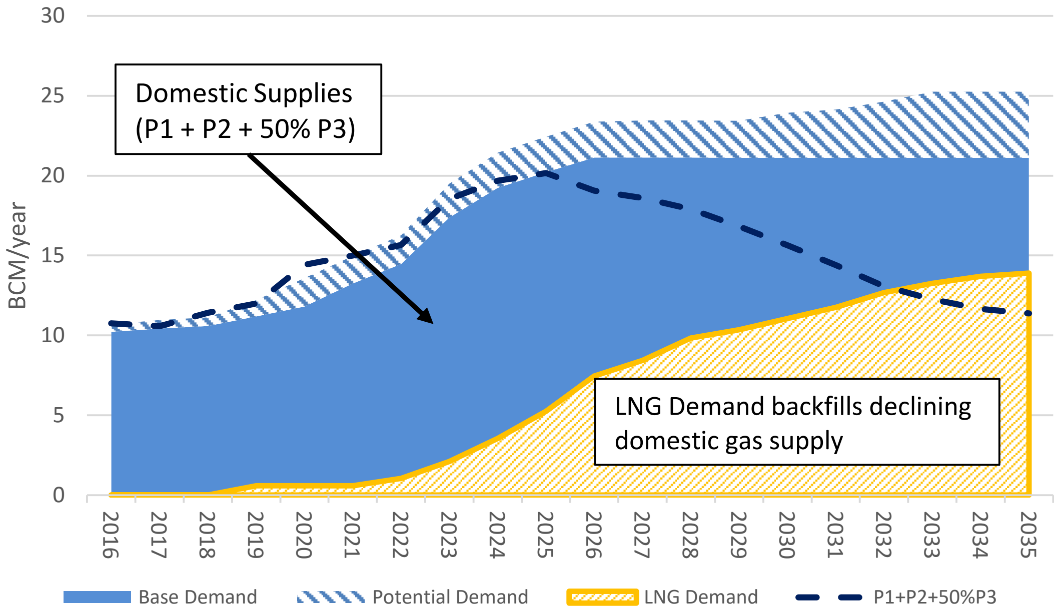


Source: Draft GMP

10.1.5 Overall supply and demand balance under the GMP

Figure 50 presents the overall supply and demand forecast as set out in the GMP. Note that this is the composite of the supply projections of the previous sections and demand forecasts and is essentially the year-by-year gas balance. This illustrates the sequence of developments with domestic reserves being developed ahead of LNG developments to "backfill" expected depletion of supply from domestic reserves.

Figure 50 Gas Production and Demand Forecast including LNG Demand based on Draft GMP Information



Source: Draft GMP

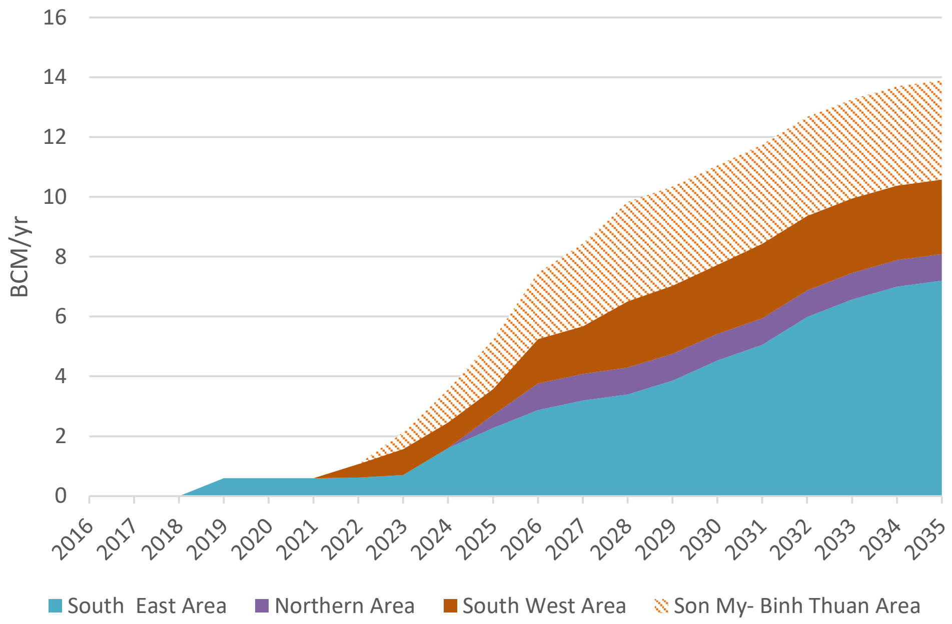
10.1.6 LNG supply and demand

As illustrated in Figure 48, P1 and P2 production levels from domestic reserves are projected to peak in the mid 2020's and then decline while production from lower probability reserves is considered to increase. Broadly, the role that the GMP sees for LNG is as a medium and longer-term measure to offset the expected decline in domestic supplies, and in particular for meeting demand for gas based power generation. Figure 51 shows the LNG demand forecast presented in the daft GMP with a small amount of LNG demand starting in 2019, and then progressively ramping up, largely just to offset the decline in production of domestic reserves and in particular as backfill to already established demands[38].

Six LNG importing terminals are proposed and were listed earlier in Table 3. The corresponding profiles of LNG import capacity as per the Draft GMP on an MTPA basis is illustrated in Figure 52. The diagram shows the LNG terminal sizes by location (site) on the left hand side and by region on the right hand side. The total MTPA by 2035 under the GMP is in the range from 12 to 18 MTPA over the period 2021-25 and from 19 MTPA to 27 MTPA by 2035. Developments in the period 2021-25 are focused on the South East and South West gas regions, while developments beyond 2026 are smaller and concentrated on Central, North and South East. The proposed LNG terminal developments collectively translate into a substantial level of infrastructure investment.

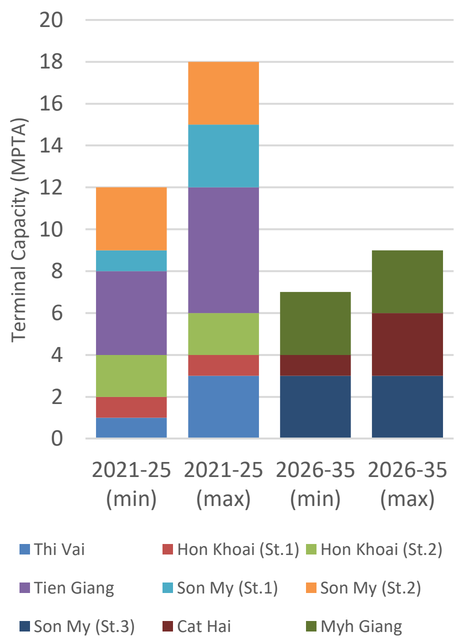
[38] Note that the government's final GMP decision identified additional LNG terminal developments, the sizes of which are reflected in the next figure (Figure 52).

Figure 51 LNG Demand Forecast under the Draft GMP[39]



Source: Draft GMP

Figure 52 LNG Terminal Sizes (Left: Size by Terminal Site, Right: Size by Region)



Source: GMP Decision

[39] Note that Son My development is unlikely to proceed, so it is shaded in the chart.

10.2 Revised Power Development Plan

10.2.1 Main features of RPDP7

In March 2016, the Revised Power Development Plan (RPDP7) was approved for the 2016-2030 period. In the revised plan, gas generation is targeted to increase from 43 TWh at present to 44 TWh in 2020 and 96 TWh in 2030. Total capacity of gas-fired power plants is targeted to increase from the current 7 GW to 9 GW and 19 GW by 2020 and 2030, respectively. These targets were very similar to the original PDP7.

In South East Viet Nam, the delivery of the 1.2 GW Duyen Hai and 1.2 GW Vinh Tan 2 coal-fired power plants in 2015 and 2014, respectively, have taken away market share from gas plants. At the same time, new coal-fired power plant projects are being developed including projects in Long Phu and Song Hau and further expansions in Duyen Hai and Vinh Tan by 2020. The utilisation of existing gas-fired power plants will drop below 50% over the next four years with all these new coal plants coming online over the next few years.

Under the RPDP7, the Son My LNG terminal in the Binh Thuan province is proposed to supplement gas for power plants in Phu My and Nhon Trach when domestic gas production in the eastern areas decline. However, note that since the RPDP7 was promulgated, the Son My LNG terminal development has been cancelled, an example of a supply risk. This has been offset somewhat by the significant discovery of gas in Central Viet Nam and progress in relation to the commercialisation of the Ca Voi Xanh field.

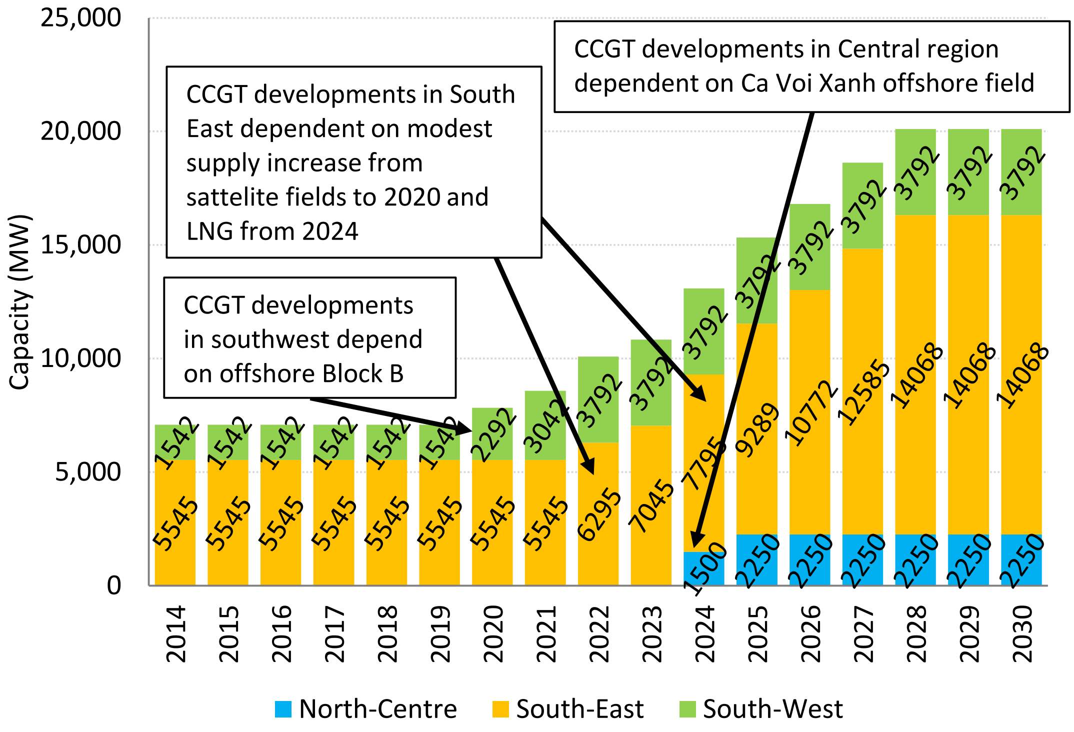
In the South West region, gas supply to the Ca Mau power plant will be shared with the existing Ca Mau fertiliser plant. New production from the Tho Chu field and the Nam Du field is anticipated for capacity expansion of the Ca Mau power plant. The O Mon power plants located further inland will have to continue to operate using diesel until the Block B&52 development and pipeline is completed.

ExxonMobil and PVN have been discussing a gas and power project in Central Viet Nam. This could see a 2,000 MW gas-fired power plant being built to use gas from the Cai Voi Xanh (Blue Whale) field. On 13 January 2017 ExxonMobil, PVN and its subsidiary PetroVietnam Exploration Production Corporation (PVEP) signed a project framework heads of agreement and a gas sales heads of agreement for the Ca Voi Xanh integrated gas development. Under the signed agreement, the two parties commit to achieving first gas for power generation by late 2023. Given the size of the reserve, power capacity could be significantly expanded in subsequent phases.

10.2.2 Gas project developments under RPDP7

Figure 53 shows the gas power projects from the RPDP7 in terms of installed capacity of gas-based power generation projects by region (South East, South West and Central).

Figure 53 Installed Capacity (MW) of Gas Project Developments in RPDP7



Source: Based on Revised Power Development Plan 7 and GMP

Based on both the GMP and RPDP7 the overall development plan for gas in the power sector is summarized as follows:

- South East region developments:
  - Phu My complex, Ba Ria and Nhon Trach currently in operation and supplied by pipeline natural gas from the Nam Con Son and Cuu Long basins;
  - GMP shows these fields are becoming depleted with gas production reducing to nearly zero by 2035;
  - An LNG terminal is proposed to be in operation from 2025 and this "backfills" gas projects in the South East Region that are filled by depleting reserves. In particular: Phu My complex, Ba Ria and Nhon Trach switch from domestic gas to LNG from 2024 and 2025 onward. This would lead to the development of Son My I and Son My II CCGTs with installed capacities of these projects eventually reaching 2250 MW each
- South West region developments:
  - Currently Ca Mau's gas supplies are from PM3;
  - South West gas production is increased with the development of Block B from 2020;
  - The O Mon complex is developed. This is as follows:
    - 2020: 750 MW of CCGT (O Mon #3);

        - 2021: 750 MW of CCGT (O Mon # 4), and conversion of 660 MW O Mon #1 to CCGT; and
    - Kien Giang project proceeds as follows:
        - 2021: 750 MW of CCGT; and
        - 2022: 750 MW of CCGT.
    - From 2026, there is a further 750 MW of CCGT (O Mon #2) which is scheduled to run on imported LNG.
- Central Region Developments:
    - Ca Voi Xanh / Song Hong basin development is expected to be in production by 2023
    - This will have the following developments: 2023-26: 5 x 750 MW of CCGTs in Central region: Mien Trung CCGT (2250 MW) and Dung Quat CCGT (1500 MW) planned
- North Region Gas Development:
    - The following CCGTs will be run on LNG:
        - Hai Phong # 3-1, 600 MW from 2025; and
        - Hai Phong # 3-2, 600 MW from 2026.

A key observation is that a substantial amount of installed capacity in the RPDP7 is dependent on both domestic offshore gas field developments in the medium term and then later on LNG imports. This highlights the fact that gas and electricity developments are not only coupled in terms of planning but care also in terms of the pricing implications – gas pricing policy may affect electricity pricing.

It is worth noting the below differences between the RPDP7, draft GMP report and the PM decision approving the final GMP.

- Hai Phong 3 CCGT (2 x 600 MW): The RPDP7 listed this project as a coal-fired power plant developed by Vinacomin in 2025-26, whereas the draft GMP indicated that it could be converted to using LNG. The latest PM approving GMP decision however has delayed the implementation of Hai Phong LNG terminal until after 2030. Therefore, the status of the Hai Phong 3 project could remain unchanged compared to what was set out in the RPDP7.
- Nhon Trach 3 & 4 CCGT (2 x 800 MW): These projects were not identified in the RPDP7 but have been included in the draft GMP on a basic of PVN's special request to the PM (in February 2016), in line with the development progress of the Thi Vai LNG terminal.

10.3 Critique of the Draft GMP

In Viet Nam, the GMP plays an important role in terms of prioritising and sequencing the required investments in the gas industry. Under Viet Nam's legal framework, it is also a necessary step in the process of enabling investment to occur. The conclusions of the Draft GMP and its recommendations appear to be reasonable and logical at a high level. They are also appropriate for a policy document. However, there are a number of observations and opportunities for improvement.

Firstly, there is an aggressive outlook for reserves and other developments. In particular, Block B having first gas by 2020 appears to be very optimistic, Ca Voi Xanh by 2023 may be feasible although based on historical lead times to development, could be quite challenging. There is also a very optimistic outlook in relation to LNG terminal developments.

Secondly, a detailed implementation chapter is not provided so implementation specifics are missing yet very important, for example, there is limited information on the development of onshore infrastructure. The sequencing laid out in the GMP for activating new gas supply sources does not appear to have an accompanying rationale. For example, there are opportunities to use least cost economics and/or draw clearer linkages to energy security so that the rationale for the sequencing of developments becomes clearer. The tradeoffs between different LNG options (onshore compared to FSRU developments for example) does not appear to have been carefully assessed either.

Thirdly, the GMP appears to have taken a supply and gross demand driven approach as follows:

- It starts with the available reserves and resources plus aggregate energy demand which has been "allocated to" gas.
- Demand-side willingness to pay for supply developments is not really examined. For example: establishing demand & supply price curves. Assessments (perhaps informed by surveys) of demand side's ability or willingness to pay for gas and what prices could be delivered by the different supply options are not considered.
- There is an opportunity to more carefully formulate supply curves and demand curves and adopt a least cost economic planning approach.
- The composition of demand is assumed as a continuation of the status quo with power demand and fertilizer plans consisting around 94% of demand and the remainder industry. Demand is also assumed to be "flat" beyond 2025, which seems unrealistic.

Fourthly, while there is reference to new pipelines, it is not clear what the priority of interconnection is, nor its timing. This is an issue that is quite important for gas market development as these developments would dictate the size and scope of the market.

Fifthly, the GMP includes a section on LNG. Key comments on this:

- The development of LNG and incremental production from existing gas resources will be critical to address power sector development and to provide access and competitive supply of gas for forecast power, industrial and fertilizer sector growth. As existing fields decline, production may not keep pace with demand, and supply shortfalls could be experienced. The implication of a near-term shortfall in supply would be a more urgent requirement to accelerate the development of new gas sources.
- The section on LNG is standalone whereas LNG should be considered as another source of natural gas which can be used to replace, backfill or supplement existing gas supplies and proposed new projects.
- There is no analysis into the value and trade-offs between LNG as a flexible resource compared to less flexible arrangements (for example, having long-term take or pay contracts associated with offshore fields) is assessed. The costs and benefits of LNG

should be evaluated in the same manner as any other gas project proposal. If LNG is the best short term solution, new thinking about LNG infrastructure solutions will be required to ensure the most appropriate facilities are installed to service Viet Nam's short and long term needs.

- There is a focus on onshore LNG receiving facilities – canvassing a wider range of LNG technologies and evaluating their fitness against Viet Nam's requirements would appear to be warranted.
- Over time, as LNG imports expand, Viet Nam's gas sector will be increasingly linked to global gas markets. Gas trade within Viet Nam has the potential for gradual liberalization as space is created for more buyers and sellers and as competitive wholesale electricity markets are introduced later this decade.

A number of final comments on the GMP are:

- The costings used for infrastructure are at the high end of international benchmarks, which is reasonable given that many of the costs are influenced more by global inputs than local labour costs.
- The relationship between the GMP and PDP is unclear and embeds risks that warrant careful analysis. For example, the RPDP7 numerous power developments are highly dependent on gas supplies in the GMP. Thus gas development risks have flow-on effects to the electricity industry that are not necessarily being recognized in the RPDP7. Clearly there are opportunities to tighten the integration between electricity and gas sector planning.
- Alternative scenarios have not been actively explored – it would be more useful if a number of scenarios were tested and analyzed and used to make informed choices about the general strategy that is formulated. For example:
  - analysis of the implications of different demand-side developments;
  - evaluation / assessments of interconnectivity between regional gas markets;
  - stress testing the implications and exposure to delays in developments across both gas and electricity industries; and
  - assessing the implications of different cost / price scenarios.

10.4 Suggested Improvements to Gas Planning Framework

There are two key areas of improvement that we suggest for Viet Nam's gas planning framework. These cover the following areas:

- General improvements; and
- Refinements to planning in support of a Gas Market.

10.4.1 General improvements

One of the key motivations for introducing a gas market is to improve decision making to be more efficient. While the gas industry is largely centrally planned, a no regrets way of doing this in the early stages to use least cost planning and economics to guide decisions. The general improvements are those that can be made to generally improve decision-making prior to having a gas market in operation. The following recommended changes address many of the shortcomings identified in the previous section:

- Improve assessments of demand-side market willingness to pay and opportunities for gas supplies.
- Use economic (least-cost planning) analysis as the basis of investment decisions in the GMP. A discussion of this was provided in section 8. Economics can be used to evaluate the pros and cons of different development choices and identifying their priorities, including but not limited to:
  - investment requirements associated with different options;
  - evaluation of interconnections between regional gas markets and/or other onshore interconnection options (e.g. connections to major industrial centres – as informed by assessments of potential demand-side opportunities); and/or
  - assessing costs and implications of different LNG options, sequencing, choices of terminal capacities, and types of LNG facilities (onshore terminals vs. FSRU).
- Undertake stress testing of exposures to key risks to the delivery of gas infrastructure and where relevant formulation of risk mitigation measures, for example: fuel price risk, delays in developments, technology costs, emissions, measures to overcome etc. These could be assessed within a broader energy security policy framework.
- Establish a more integrated approach to planning generally, so that the consequences of gas infrastructure and gas development options can be understood more broadly across relevant sectors, gas, electricity, coal, industrial developments (fertilizer plants, manufacturing, industrial parks etc.), climate and more integration between supply and demand sides of the gas industry. This will also better facilitate trade-offs between sectors, identification of opportunities for substitution, and enable a more informed assessment of risks to the delivery of energy services to the economy.
- Evaluate the implications of different scenarios on energy pricing – for example, prices delivered to various market segments (power, industry, large consumers, medium size consumers etc.) and flow-on effects – gas pricing's implications for electricity prices for example. Again, this type of analysis would enable risks and trade-offs between different sequences of gas industry investment to be better understood, enabling any development sequences or strategies for the gas industry to be better informed.

10.4.2 Gas industry planning when there is a gas market

Investment in mid-stream infrastructure in the form of interconnecting pipelines, gas processing facilities and LNG receiving terminals will be required to permit trading of gas between current and prospective buyers. A third party access regime for such infrastructure will be required to oversee terms and conditions, including tariffs, for access to infrastructure. Therefore, gas industry planning will continue to be an important part of energy planning in Viet Nam in the transition towards a liberalised market and beyond.

The approach for gas industry planning however needs to be refined so that the implications for competitive and non-competitive elements of investment decisions are assessed. In relation to the non-competitive (or regulated) part of the industry, any investments need to be assessed with respective to the benefit that they will bring the market. For example, mid-stream infrastructure opportunities should not only be evaluated with respect to economic cost-benefit assessments but also with respect to the implications for a gas market: for example, the implications for competition, market size and market efficiency. Gas planning within a liberalised gas market should also identify and highlight where opportunities for investment or participation exist for either existing or new market participants.

Specific adjustments to gas sector planning to accommodate a gas market include:

- To avoid the perception of bias or conflicts of interest gas industry planning should be carried out by an independent body (MOIT or GDE for example engage the services of an independent organisation). There may need to be provisions or obligations imposed on existing participants to provide data and information necessary to ensure that the required modelling / assessments can be carried out.
- Gas planning needs to evaluate the market benefits of different investment options, which requires an assessment of:
  - market competition and efficiency (the extent to which investments increase the numbers of buyers and sellers and enhances allocative efficiency);
  - reduction in the costs of transactions;
  - reductions in barriers for new entry and/or creation of opportunities for greater participation;
  - improve and enhance access and use of gas reserves;
  - enhance ability for risks to be managed: risks to participants and new entrants; and
  - identification of potential opportunities for new participants / existing participants or the extent to which their consumers would have increased options of gas suppliers and contract counterparties.
- Improved transparency in relation to: (1) assessments of previous gas market outcomes, (2) assessment of supply and demand fundamentals, (3) explanation and data on the key results of planning, will also lead to higher levels of investor confidence and will enhance their ability to make well-informed decisions.

10.4.3 Implication of changes

To effect the changes discussed in section 10.4.1 and 10.4.2, the legal framework for gas industry planning as defined by Prime Minister Directive No. 296/TB-VPCP, would likely need to be refined to encompass the above.

10.5 Summary and Transitional Steps

10.5.1 Summary

There are opportunities for enhancing gas industry planning in Viet Nam in two areas. The first is a set of general enhancements that aim to improve the efficiency of decision-making by introducing economics and undertaking more comprehensive assessments of risks. The second set of enhancements are to transition planning to be more market oriented. The former set of enhancements are of a “no regrets” nature and should be introduced irrespective of a market transition.

10.5.2 Transitional steps

The recommended transitional steps for gas sector planning are as follows:

Step 1 – to 2020

- Retain the status quo: PVN undertakes planning on behalf of the gas industry.
- Supply and demand projections approach continues.

Step 2 – 2021 to 2025

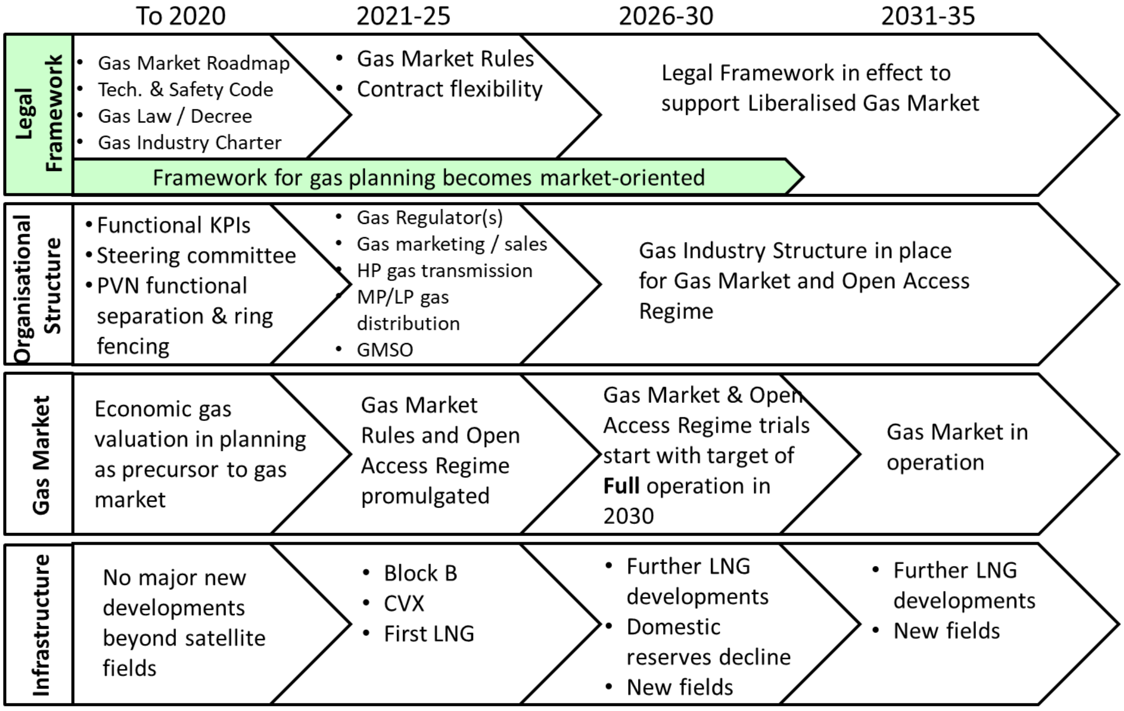
- Independent organisation becomes responsible for gas planning.
- General enhancements to gas industry planning are introduced.
- Use of economic cost-benefit evaluations and least cost planning to determine efficient investments.
- Enhance integration between gas, electricity, industry, and other sectors.
- Improve transparency with publication of detailed findings.

Step 3 – post 2025

- Reorient Gas Industry planning to be “market-oriented”.
- Evaluate market benefits for different investment options.
- Identify and publish opportunities for investments in Viet Nam’s gas industry.
- Improve transparency with publication of detailed information on assessments of market opportunities and information on Viet Nam’s gas sector.

Figure 54 shows the Roadmap with the components relevant to gas industry planning shaded. Note that these changes will require enhancements to Prime Minister Directive No. 296.

Figure 54 Transitional Steps for Gas Industry Planning



PART E: LEGAL AND REGULATORY FRAMEWORK TO SUPPORT VIET NAM’S GAS MARKET

11 Required Legal and Regulatory Framework to Support a Gas Market in Viet Nam

11.1 Required Legal and Regulatory Framework

As described in sections 4 and 5, the legal and regulatory framework for Viet Nam's gas industry is largely defined by the following documents:

- PVN Charter which defines PVN's role and responsibilities;
- Prime Minister Directive No. 296/TB-VPCP dated 27 July 2014 – which defines gas industry planning;
- PM Decision No. 60/QD-TTg dated 16 January 2017 approving the Plan for Development of the Viet Nam Gas Industry by 2025 with Vision to 2035 (GMP); and
- Numerous internal business procedures within PVN that govern their operations.

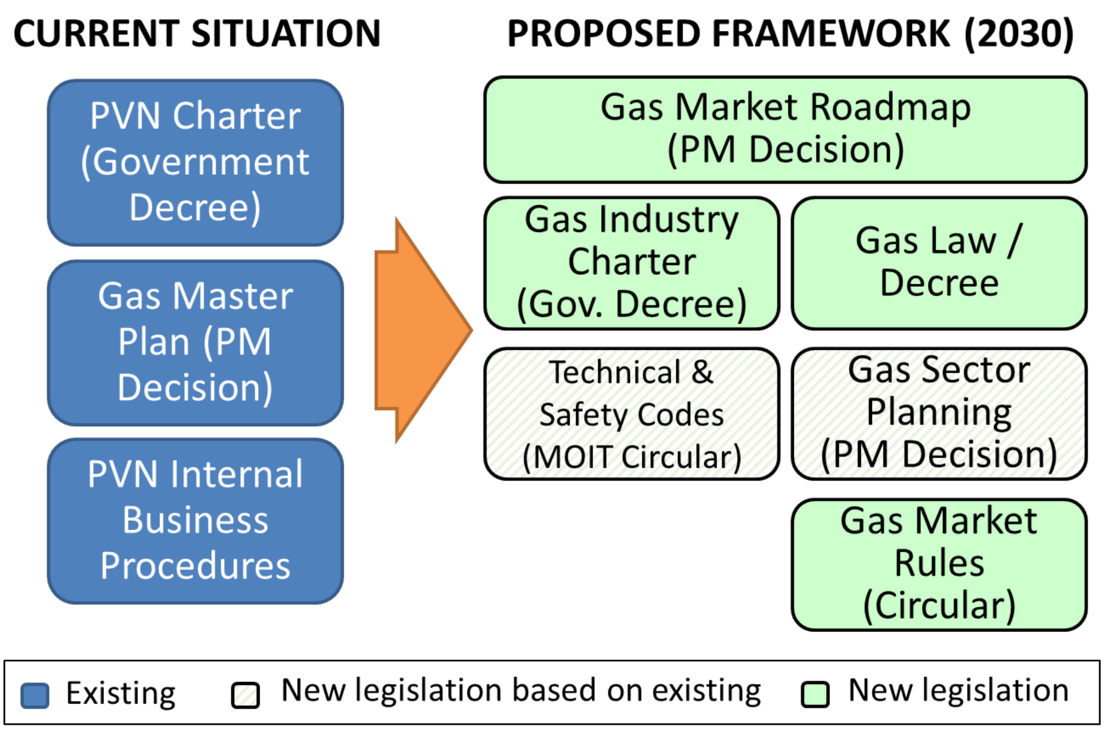
These largely are concerned with defining the operation of PVN and Viet Nam's gas market in its present form and are not adequate to support a Gas Market in Viet Nam. As part of the transition towards a liberalised gas market, it will be necessary to establish a legal and regulatory framework that formalises a number of elements of the gas industry to enable greater participation, define the key roles and responsibilities of the entities to govern the gas industry and to establish rules for the gas market.

It is important to ensure that the legal and regulatory framework caters to both the unique aspects of Viet Nam while also being an example of international best practices. The latter is because the transparency, stability and standardisation of the legal and regulatory framework lays the foundation for foreign participation in Viet Nam's gas industry and the associated significant investments that will be required.

Figure 55 illustrates the key features of the current legal and regulatory framework and a proposed model for legislation by 2030. Much of the new legislation can be based on existing legislation with revisions to support a market or by formalising internal business procedures of PVN into regulations that apply to the industry in general.

The Gas Market Roadmap and Gas Market Rules would be the main aspects of the legal and regulatory framework that are entirely new. It should be noted that this structure is largely compatible with the arrangements in place for Viet Nam's electricity industry (and as developed under the Electricity Reforms Roadmap) therefore this creates a future opportunity of consolidating the gas and electricity industries of Viet Nam at the future, if that was ever desired.

Figure 55 Required Legal and Regulatory Framework



11.2 Gas Market Roadmap (Prime Minister Decision)

As a Prime Minister Decision, the Gas Market Roadmap defines the stages and sequence of steps necessary to transition Viet Nam's present gas industry arrangements towards a liberalised gas market. It should also make clear any preconditions that would be necessary for transitioning from one step of the Roadmap to the next. The primary objective of this project has been to define the Roadmap and we provide detailed coverage of its content as the conclusion of this report in section 12.

11.3 Gas Supply Industry (GSI) Charter (Government Decree)

The rationale for the GSI is to essentially codify the transformation of PVN's organisation into a form that is required to support the operation of a Gas Market. It must be legislated at an equivalent level to the PVN Charter, and in fact, would supersede the PVN Charter. The GSI Charter would additionally define the governance structure for the entire gas industry. We suggest that the GSI Charter be implemented as a Prime Minister (PM) Decision.

The GSI Charter should provide reflect the transitional steps for PVN's restructuring that we have set out in Section 7. The reason for keeping this separate from the Gas Law is because it is concerned with taking the current structure of PVN and transforming it to into entities that will later take on roles that would be defined in the Gas Law and Gas Market Rules. Therefore the Gas Law and Gas Market Rules would be availed of the need to address what eventually becomes a legacy issue.

The content of the GSI Charter would therefore be to define the key entities for Viet Nam's Gas sector, based on the structure we have set out in section 6, including:

- Role of MOIT / GDE in relation to gas industry:
  - Gas sector policy;
  - Gas Market rulemaking and changes;
- Gas Regulatory Authority of Viet Nam (GRAV);
- PVN Gas Single Buyer (GSB);
- Gas System and Market Operator (GSMO);
- PVN Gas Transmission Service Provider (GTSP);
- PVN Gas Distribution Service Provider (GDSP); and
- End users / Gas Customers.

It would then contain a section that sets out transitional steps for the PVN which could be based on the proposed steps set out in section 7.5.

11.4 Gas Law (Government Decree)

Gas Law content would include:

- Separation and delineation of market development from the wide energy policy context;
- Management of the gas infrastructure development planning: participants in the planning process and levels of involvement, contents of the planning and execution procedures.
- Regulations for infrastructure project investment and construction management; approval and issuance of investment licenses, business registrations with required technical, commercial and environmental conditions and standards.
- Rules on setting up of the monitoring / regulatory entities to oversee related activities, in particular gas transportation and distribution.
- Third party access to gas pipelines.
- Provisions for introduction / development of a gas market; and
- Principles for the treatment of legacy gas contracts.

11.5 Gas Market Rules (Circular)

The Gas Market Rules would define the following:

- Regulations on gas products and services quality; gas pricing, transportations fees and other charges setting rules.
- Gas purchase and gas transportation agreements.
- Gas cost allocation and accounting regimes.
- Rules enforcement and dispute resolution.
- Conditions & requirements for participation in the gas market; rights and responsibilities of market participants.

- Operational codes and procedures for gas pipelines and gas dispatch.
- Gas metering regulations as they pertain to gas market transactions.

It should be noted that the Gas Market Rules needs to be able to be changed more frequently as compared to the Gas Law or the GSI Charter, hence we have recommended Circular level legislation. This would enable the Gas Market Rules to be updated over time and in accordance with a well-defined market rules change process that could be managed by GRAV (say) with approvals for changes given by MOIT, following stakeholder consultation. The key point is that the Rules will inevitably need refinement over time, while the Gas Law and the GSI Charter should not require frequent changes or revisions.

11.6 Gas Sector Planning and Economic Valuation Framework

The gas sector planning is largely already in place, but as we noted in sections 10 and 8 it needs to be adapted to a Gas Market environment. The following adjustments / refinements to the existing GMP framework are proposed to be made in two steps as defined below.

11.6.1 Step 1: Enhancements to gas industry planning framework

- Make greater use of economic cost-benefit evaluations and/or least cost planning to assess alternative investment options and to formulate the sequence investments;
- Tighter integration across supply and demand in gas and across closely related sectors;
- Evaluation of risks and formation of mitigation measures via scenarios and stress testing analysis, as informed by energy security directives;
- Evaluation of the implications on energy pricing;
- Improve transparency with publication of detailed evaluations and data on the gas industry. Establish and approve a standardised economic cost net-back methodology; and
- Establish and approve a standardised economic cost net-back methodology to simplify and standardise economic valuation of natural gas.

11.6.2 Step 2: Market oriented gas industry planning framework

- Planning undertaken by an independent organisation;
- Evaluate market benefits of different investment options; and
- Improve transparency with publication of detailed evaluations, assessments of market opportunities and data on the gas industry.

11.7 Technical, Safety and Environmental Protection Codes

These include equipment standards, metering standards, safety standards and environmental protection standards. The technical, safety and environmental protection codes must be externalised from PVN internal procedures because they need to apply to all entities that operate within Viet Nam's gas sector. Technical conformance must also be carefully and transparently monitored by the GRAV. We suggest this also be legislated as a Circular, because it will likely need to evolve over time, and will need to undergo a change process that allows it to be updated more frequently compared to a Government Decree or PM Decision.

11.8 Summary and Transitional Steps

11.8.1 Summary

Key legal documents that need to be developed in order to support a Gas Market in Viet Nam are as follows:

- Gas Market Roadmap, as a PM decision;
- Gas Sector Planning laws, updated to reflect required enhancements as a PM Decision;
- Gas Supply Industry (GSI) Charter, as a Government Decree;
- Gas Law, as a Government Decree;
- Technical and Safety Code of Practice, as a Circular (or set of Circulars); and
- Gas Market Rules, as a Circular.

11.8.2 Transitional steps

Most of the key legislation required for a Gas Market can be drafted and promulgated ahead of major industry changes. The sooner this can occur the better, because it will provide stakeholders within the industry and potential investors in the future with certainty in terms of how Viet Nam's gas industry will be transformed over time. Hence we recommend to establish as much legislation as possible in the period to 2020.

The following transitional steps are recommended for Viet Nam's Gas Industry legal and regulatory framework:

Step 1 – to 2020

- Gas Market Roadmap.
- Technical, Safety and Environmental Protection Codes.
- Gas Law.
- Gas Supply Industry Charter.

Step 2 – 2021 to 2025

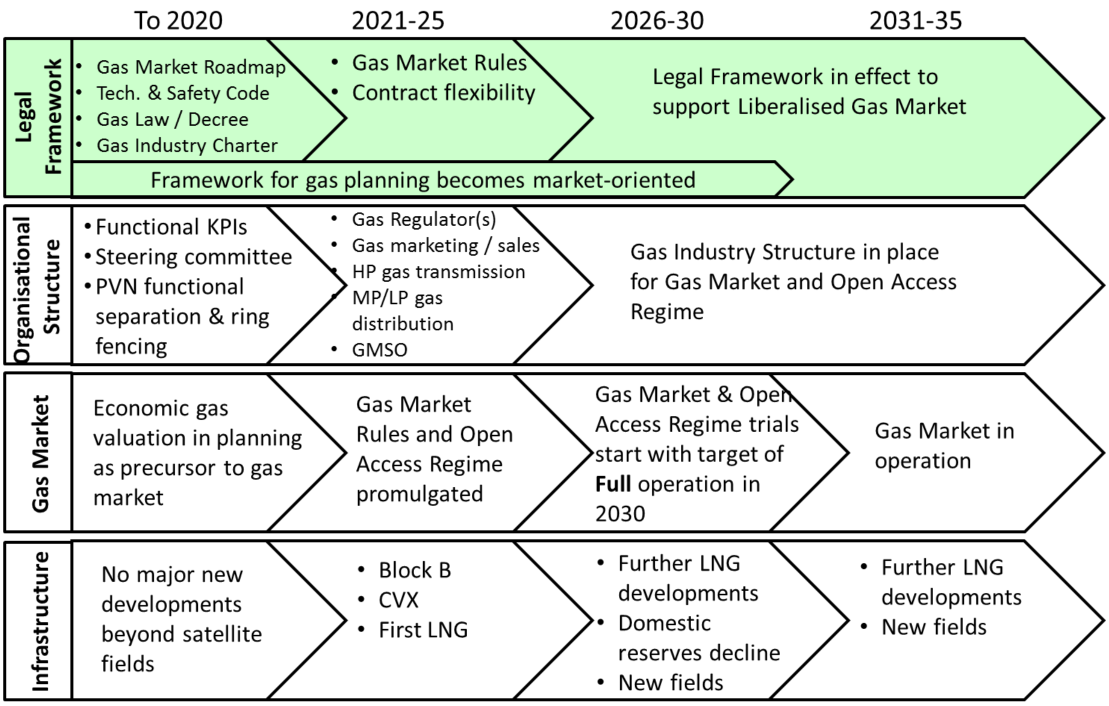
- General enhancements to the Gas Industry Planning.
- Gas Market Rules.

Step 3 – post 2025

- Changes to Gas Industry Planning Legislation to be market-oriented.

Note that this means that by 2025, all of the key legislation would be in place to support a Gas Market. Figure 56 sets out the transitional steps for the legal and regulatory framework necessary for Viet Nam to have a Gas Market in place. The relevant components of the Roadmap are shaded.

Figure 56 Transitional Steps for Legal and Regulatory Framework



PART F: VIET NAM'S GAS MARKET ROADMAP

12 Proposed Gas Market Roadmap for Viet Nam

12.1 Approach to Gas Market Roadmap

Viet Nam's oil and gas industry has historically been a priority area of development because for the purpose of stimulating economic development and because the industry makes a significant contribution to the country's fiscal balance[40]. Viet Nam Oil and Gas Group (PVN) has established itself as a major contributor to Viet Nam's economy. While this has been a highly successful approach in the early stages of Viet Nam's gas industry, as described in section 2.1, the recent outcomes and performance of Viet Nam's gas industry has prompted the Government to issue a directive that seeks to improve the efficiency of the industry by taking steps towards liberalising the industry.

The Government Directive (section 2.2) sets the scene for the Gas Market Roadmap ("the Roadmap"), which is intended as a strategic legal document that forms the basis of a step-by-step transition of Viet Nam's gas industry towards one that support a Gas Market. The Roadmap needs to be a concrete action plan for Gas Market evolution in Viet Nam with clearly identifiable steps and preconditions for transitioning from one step to the next. It should be largely consistent with the direction of the Directive but set out the necessary and detailed steps for transforming Viet Nam's gas industry.

This report has identified and analysed the issues and barriers to creating a liberalised gas market, with the account for Viet Nam's unique conditions and reference to experiences of international markets. The report has also carefully considered and proposed transitional steps that forms the basis of the Roadmap. In particular, we have analysed the current state and development options for Viet Nam's gas industry, performed a detailed review of the governance and industry structure, assessed economics, pricing and planning in Viet Nam's gas sector and finally performed a high level assessment of the necessary legal and regulatory framework that would be required in Viet Nam to support a gas market.

In order to ensure that the proposed Roadmap is appropriate for Viet Nam, we also reviewed in detail the approach that Viet Nam has taken under the Electricity Industry Reforms Roadmap, a detailed discussion of which is in Appendix G. Key lessons from Viet Nam's electricity industry roadmap form the basis of the principles we have used in the formulation of Viet Nam's Gas Market Roadmap:

- Clear statements of the transition steps that are necessary and defining these in a way that will avoid any sudden or radical changes. The steps must define the actions, preconditions, and desired outcomes.
- Identify suitable periods of time when reviews of progress should be conducted ahead of progressing further or making some refinements / adjustments to future steps.
- Define the timeframe of the steps to provide certainty to industry stakeholders and potential future investors of the wider direction of the industry.

[40] M. R. Tsibulnikova, V. A. Pham, T. Yu Aikina, "Outlook for the Development of Oil and Gas Industry in Viet Nam", IOP Conf. Series: Earth and Environmental Science 43 (2016) 012094.

- Define the legal and regulatory documents that need to be developed and the associated timing.
- Define the changes in relation to governance and industry structure.
- Draw linkages between legislation and the development of physical infrastructure.
- The outcome of the market evolution will be building on and measured by the extent to which the issues outstanding to the sector are being addressed.

Another key criterion that we have used in the formulation of the Gas Market Roadmap is to ensure that is synchronised with the electricity industry reforms roadmap, a topic we discuss further in section 12.5.

12.1.1 Gas Market Roadmap structure

The Gas Market Roadmap has been structured in the following way, and draws upon similar other roadmap decisions in the country:

Periods of time are set as follows:

- Up to 2020 Period;
- 2021-25 Period;
- 2026-30 Period; and
- 2031-35 Period.

The key dimensions of areas where transitions need to be achieved:

- Legal and Regulatory Framework:
- Gas Sector Organisational Structure;
- Gas Trading (Market) Mechanisms; and
- Supporting processes and Infrastructure.

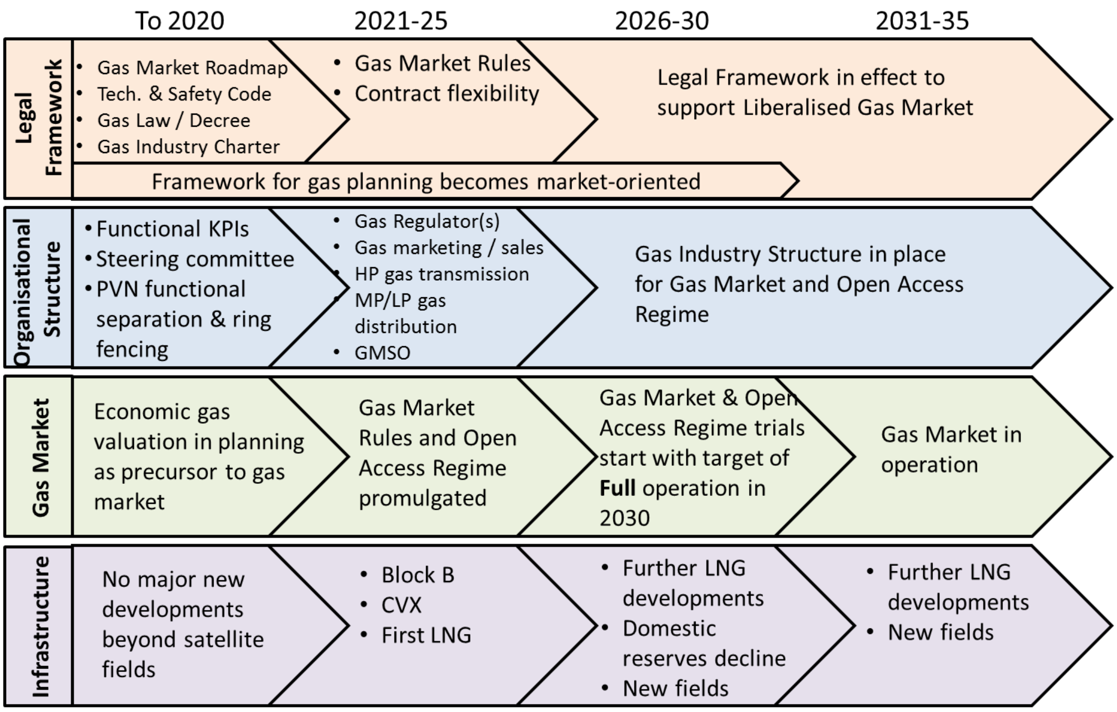
We described these dimensions earlier in section 3.

12.2 Proposed Gas Market Roadmap

Figure 57 sets out the proposed Gas Market Roadmap. It has been constructed in a way that is similar to other Roadmap legislation in Viet Nam and which has been staged in a way that is consistent with directives in the Gas Master Plan decision promulgated in 2017. It carefully transitions the Gas Industry of Viet Nam in a way that is similar to the Electricity Industry Reforms Roadmap of 2013, and in doing so creates an opportunity for some consolidation of gas and electricity sector governance in the longer term, if that was desired.

As with other Roadmap decisions in Viet Nam, we describe its content time period by time period in the following subsections. In this way, the content presented here could form the basis of content for the Prime Minister’s decision on the Gas Market Roadmap.

Figure 57 Proposed Gas Market Roadmap



12.2.1 Period to 2020

The necessary legal and regulatory framework to support a Gas Market should be established as soon as possible to provide certainty to the industry. These can proceed as the first steps towards organisational and industry re-structuring are taken. Furthermore, a number of no-regrets improvements are recommended to be done in this stage in order to improve decision-making as it relates to economics and planning. It is also proposed to put in place functional Key Performance Indicators (KPIs) on PVN's business units as part of functional separation to ensure the role of newly formed business units is clearly defined.

Legal and regulatory framework to 2020

Proposed legal and regulatory framework changes:

- Finalisation and promulgation of the Gas Market Roadmap as a Prime Minister Decision.
- Develop industry wide Technical & Safety Codes (preferably based on international standards) to provide industry and project specific standards and procedural guidance.
- Development and promulgation of the Gas Law as a Government Decree. It would define the regulated and non-regulated (competitive) elements of the gas sector, licensing requirements, access regimes, pricing principles and approaches for different industry segments including any overarching arrangements fundamental to the gas industry.

- Development and promulgation of the Gas Industry Charter. This would define the key entities and their responsibilities in Viet Nam's Gas Industry and is a precondition for starting the Gas Market.
- General enhancements gas industry planning framework put into place to come into effect from 2021, including:
  - Use of economic cost-benefit evaluations and least cost planning to determine efficient investments.
  - Improvements to leverage standardised economic valuation of natural gas framework.
  - Enhance integration and coordination between gas, electricity, industry, and other sectors.
  - Improve transparency with publication of detailed findings.

Organisational structure to 2020

The following are the key recommendations during the initial stages of Gas Market Roadmap:

Form a Gas Market Steering Committee (GMSC) under MOIT:

The GMSC would have the authority and mandate to progress the Gas Market Roadmap. The GMSC would be responsible for reporting on Gas Market Roadmap progress, conducting studies, monitoring outcomes and assessing progress. Where relevant the GMSC would make recommendations to refine or revise the Gas Market Roadmap. Specific responsibilities for the GMSC include:

- Development of the Gas Law and a Gas Industry Charter;
- Design of Gas Market / Trading Mechanisms; and
- Development of the Gas Market Rules.

The GMSC would likely be structured to ensure that there was representation of staff who cover: legal and regulatory expertise, gas industry planning, technical operation of the gas industry, gas pricing, gas contracting and economics.

Undertake the first steps of an organisational restructure of PVN:

Restructuring of PVN should commence with the separation of non-oil and gas businesses, such as banks, being moved out of the core business structure into separate reporting lines to the Board of Directors, with a view to ultimate divestment of those businesses. The key activities in relation to PVN restructure to 2020 that we recommend are:

- Separation of non-oil and gas business from all oil and gas activities;
- Technical regulation, market regulation and policy advice to GDE separated from any operational business unit. Note that the number of agencies focused on safety and associated technical compliance should be minimised.
- Construction, engineering and technical service providers and associated functions moved into a separate business unit.

- PVN functional separation and ring-fencing of GMSO, HP gas transmission, MP/LP distribution and marketing and sales commences.
- Introduce transparent and measurable KPIs and benchmarking measures.

The following aspects of Viet Nam's gas industry structure do not change over this period:

- MOIT / GDE continues to be responsible for gas industry planning and policy direction;
- PVN continues to internally regulate gas industry operations and compliance with technical and safety codes;
- Gas system operations remain as they are within PVN;
- EVN NLDC operates the VCGM and as per their mandate. The VWEM will commence operation with NLDC becoming the System and Market Operator (SMO).

Gas market developments to 2020

During the period to 2020 stage we recommend steps be taken to standardise and improve the methodology for economic valuation. This is in order to improve decision-making and intended as a precursor to phasing in a Gas Market. It is also intended to improve decisions related to gas infrastructure planning.

The following two steps are proposed:

Step 1:

Develop and approve economic valuation methodology:

- Transparent published framework and guidelines.
- Reference sources of cost data and information.
- Checklist of investment criteria including milestones, decision gates and timing.

Apply to integrated economic resource and project planning and resource allocation:

- Technology, environmental and geographic neutrality, including: location, plant types, incremental costs, project timing, economic life and scale etc.
- Exogenous factors addressed, including: emission and emergent technology policies, fiscal adjustments, project security and risk, balance of trade impacts and competition benefits.

Step 2 (to 2020, or until competitive gas market is in operation):

Apply economic gas valuation methodology into gas development planning:

- Compare and prioritise domestic gas resource and LNG development delivery.
- Assess options for gas pipeline and transmission network development.
- Input to gas valuation policy for generation projects, industrial, fertiliser and other gas users.
- Benchmarking and sand-pit assessment of energy policy initiatives and energy market design.

Note that no changes would be made to any commercial arrangements during this stage.

Infrastructure developments to 2020

There are no major infrastructure developments in this period.

12.2.2 Period from 2021 to 2025

The period from 2021 to 2025 should commence with a review of the progress that has been made in the period to 2020, to ensure that the following preconditions have been satisfied:

- Gas Law and Gas Industry Charter have been promulgated as Government Decrees.
- Technical and safety codes are in place as one or more industry-wide Circular(s).
- GMSC in place to oversight Gas Market development in accordance with the Roadmap.
- Progress made in relation to PVN restructuring.
- Economic valuation framework in place and being used to guide decision-making in the gas industry.

Assuming that these preconditions are satisfied, then further progress for Gas Market development can be pursued, otherwise measures to ensure all preconditions are satisfied should be taken before progressing.

The broad objective of this period is to complete a number of changes to Viet Nam's legal and regulatory framework necessary to support a Gas Market, and for PVN's restructuring to reach its conclusion. In this way, Viet Nam's gas industry by 2025, should satisfy all key preconditions for starting a Gas Market.

Legal and regulatory framework from 2021 to 2025

During this period the Gas Market Rules will be developed and promulgated, regulations to allow flexibility in existing gas supply contracts would be introduced and existing regulations which inhibit gas trading would be amended or repealed. These regulations would not amend contracts, but would provide the basis for the parties to those contracts to negotiate mutually beneficial amendments.

Specific actions we recommend for Viet Nam's legal and regulatory framework during the period from 2021 to 2025 are:

- Implement independent and transparent consultation process for technical and safety code and later Gas Market Rules review and modification.
- Gas Market Rules would be developed and promulgated as a Circular.
- Implementation of an open access regime for gas pipeline connection and transport.
- General enhancements to the Gas Industry Planning come into effect and the following changes would be developed and promulgated to come into effect from when the Gas Market commences commercial operation (2026):
  - General enhancements to gas industry planning are introduced.
  - Use of economic cost-benefit evaluations and least cost planning to determine efficient investments.
  - Enhance integration between gas, electricity, industry, and other sectors.

– Improve transparency with publication of detailed findings.

Organisational structure from 2021 to 2025

During this period the GMSC continues to oversight and progress the Gas Market Roadmap.

The following are the key recommended changes to gas industry governance during this period:

- Under the Gas Law, establish an independent gas economic, technical and safety regulator(s) similar to the power industry's ERAV with responsibility and appropriate powers for industry monitoring, compliance and enforcement. The entity could be called Gas Regulatory Authority of Viet Nam (GRAV).
- An independent organisation under MOIT becomes responsible for gas planning. This entity should have the autonomy and budget to hire an independent consultant to conduct the Gas Master Plan (GMP).

During this period, following a review of progress in relation to the initial steps of restructuring PVN over the period to 2020, further progress should be progressed in relation to restructuring PVN as follows, and ideally completed no later than 2023:

- Mid-stream and down-stream gas business functions including particularly PVGas, separated from the upstream oil and gas businesses and service providers.
- Establish an independent gas economic, technical and safety regulator.
- Gas management and system operations transferred to an independent agency.

Gas market developments from 2021 to 2025

During the period from 2021 to 2025, the GMSC (with input from MOIT and GDE) should:

- **Step 1 (by 2022):**
  - Complete an evaluation of Gas Market Design options and promulgate Gas Market Detailed design regulation[41].
  - Develop the draft Gas Market Rules and undertake stakeholder consultation on draft versions of Gas Market Rules.
  - Remove restrictions and permit flexibility in gas contracts where counterparties have mutually agreed to this.
  - All new gas contracts entered into to have a higher degree of flexibility to enable gas volumes to be traded if desired.
- **Step 2 (by 2025):**
  - Finalise and promulgate Gas Market Rules and an open access tariff regime.
  - Assign the responsibility for operating the Gas Market (in a Pilot and Full operation mode) to the GMSO as the independent gas market and system operator. The commencement of Gas Market is suggested for 2026.
  - Establishment of a bulletin board to publish market data.

[41] Consistent with the approach that was taken for the Viet Nam Wholesale Electricity Market (VWEM).

Infrastructure developments from 2021 to 2025

During this period, under the GMP of 2017:

- Block B and Ca Voi Xanh are planned to come into production; and
- Viet Nam will commence first LNG imports; and
- The necessary investments in ICT infrastructure to enable the Gas Market to operate according to the Gas Market Design and Gas Market Rules have been made.
- Publication of key industry data in a timely manner to gas market participants and/or to potential investors.

In the electricity industry, the System and Market Operator (SMO) is planned to undergo a number of steps towards becoming independent from EVN.

12.2.3 Period from 2026 to 2030

The primary objective of this period of the Gas Market Roadmap is to go through the process of piloting the gas market and commencing its full operation.

The following preconditions should be satisfied prior to commencing the changes we recommend for this period:

- Independent gas economic, technical and safety regulator (GRAV) established, staffed and in place;
- An Independent planning organisation under MOIT established and in place for oversighting gas industry planning;
- Gas Market Rules and open access arrangements have been promulgated and are in place;
- GMSO operating as a fully independent entity and responsible for gas market and system operations; and
- PVN restructuring has reached its conclusion and PVN's separate entities are ready to take their assigned roles in the Gas Market.

Legal and regulatory framework from 2026 to 2030

By 2026, all of the key legislation necessary to support an open and transparent Gas Market should be in place. The changes to the legal and regulatory framework envisaged during this period are:

- Incremental changes to the Gas Market Rules and Technical Codes, as required based on experience in the commencement of a Pilot and Full Gas Market
- Revisions to the Gas Master Planning framework to be market-oriented should come into effect from 2026.

Organisational structure from 2026 to 20230

By 2026, the governance and organisational structure of Viet Nam's gas industry necessary to support the operation of a Gas Market should be in place.

It is suggested that the following be undertaken during this period:

- GMSC conducts annual reviews of the outcomes of the Gas Market with a view to assessing the extent to which the Gas Market operates efficiently and in accordance with the wider objectives of Viet Nam's gas industry.
- Depending on government policies and financial considerations, the downstream businesses of PVN could be considered for divestment.
- GMSC also conducts a review of the effectiveness of the recently formed entities in taking on their responsibilities under the Gas Market.
- GRAV monitors and routinely reports on Gas Market Rules compliance and also monitors and on the outcomes of the gas market to GMSC.

Gas market developments from 2026 to 2030

The overriding objective of the premarket development track in this period is to trial (or Pilot) Gas Market operations ahead of full commercial operation starting. Piloting the Gas Market provides the opportunity to make any refinements and identify and mitigate any risks ahead of the Gas Market commencing full commercial operation. Risks for example, may relate to ICT system issues that need to be resolved or issues arising from the incompleteness of Gas Market Rules.

- **Step 1 (Prior to the end of 2026):**
  - GMSO commences Pilot (or Trial) operations of the Gas Market and is responsible for operating the required Gas Market processes and publishing the relevant information.
  - Following a period of 6 months, GMSC and GRAV would be jointly responsible for completing a detailed review of the Pilot Gas Market ahead of starting full commercial options. As part of the review any refinements to the Gas Market Rules should be identified and implemented.
- **Step 2 (by 2027):**
  - GMSO commences full commercial operation of the Gas Market and is responsible for operating the required Gas Market processes and publishing the relevant information.
  - Key features of the Gas market would be:
    - Open access arrangements in place;
    - New gas contracts would have volumes traded via the Gas Market; and
    - Legacy gas contracts where parties have agreed can have volumes traded via the Gas Market.

Infrastructure developments from 2026 to 2030

During this period, in accordance with the GMP of 2017:

- Continued development of infrastructure to support LNG imports in Viet Nam;
- Domestic offshore reserves production levels start to decline;

- Yet to find offshore / domestic reserves of gas may be identified and planned for development (under the economic and planning framework that has been established in the period to 2025); and
- The opportunity of tighter physical interconnectivity between gas regions should be explored in light of a market-oriented GMP, specifically with respect to the extent to which it would deliver benefits to the Gas Market.

Also during this period, the ICT systems for Gas Market operations should be set up and put in place. As a minimum, the ICT systems should support the following:

- Publication of key industry data in a timely manner to gas market participants and/or to potential investors; and
- Provide for the implementation of the Gas Market Rules (where the Gas Market design is yet to be defined).

12.3 Period from 2031 to 2035

As illustrated in Figure 57, beyond 2031, the Roadmap envisages having the following in place:

- The necessary legal and regulatory framework to support a Gas Market;
- The necessary government and industry structure in place for a Gas Market;
- There is an entity established (GRAV) that has the role of regulating the Gas Industry;
- The Gas Market itself has commenced full operation and is managed by GMSO as an independent entity that has no role in buying or selling gas; and
- There are open access arrangements in place.

With these steps having been completed, the main focus of the period from 2031 to 2035 is one of review and refinement to the Gas Market as part of an ongoing effort to ensure that the Gas Market delivers efficient outcomes for Viet Nam's energy industry.

Legal and regulatory framework beyond 2030

By 2031, GMSC could lead a final investigation and review of the Gas Market Roadmap progress. It should assess the successes and lessons learned in the implementation and identify any final areas of work that would be required to fulfil the requirements of the Gas Market Roadmap. Any refinements or improvements to the legal and regulatory framework would now be assessed with reference to ensuring the Gas Market can deliver efficient operational and investment outcomes. At this point, it would also make sense to evaluate the need for a Gas Retail market, as envisaged by the Government in the GMP of 2017.

Organisational structure beyond 2030

The main features of organisational structure envisaged by 2030 are:

- GMSC's role could end once it has been concluded the Gas Market Roadmap has been successfully implemented.
- Depending on government policies and financial considerations, the downstream businesses of PVN could be considered for divestment.

- The industry structure should now support greater participation of new entities in Viet Nam's gas sector on both the supply and demand sides of the industry.
- GRAV's role of continuing to monitor compliance to technical codes and the market rules and will need to be mindful of reviewing and assessing the level of competition in the Gas Market.
- It would make sense to assess the feasibility because there would likely be efficiency gains to be captured, of consolidating the SMO (of the Viet Nam electricity market) and GSMO into a single organisation responsible for system and market operations of both gas and electricity markets.

Gas Market Developments from 2031 to 2035

As stated, during this phase, review of progress and outcomes of the Gas Market to date is warranted along with the assessment of whether any refinements and/or adjustments are required to enhance its operation. Consideration of the feasibility and need for a retail gas market could be contemplated at this stage.

Infrastructure developments from 2031 to 2035

The GMP of 2017 envisages further LNG imports to largely backfill the expected decline in production from offshore gas fields. The possibility of greater physical interconnectivity between gas regions (which would likely work in the favour of gas market development) remains an opportunity to be explored just as any yet to find offshore gas reserves being brought into production is.

12.4 Gas Market Roadmap Tabulated Matrix

To complete the diagrammatic representation of the Gas Market Roadmap, we have tabulated a more detailed version of the key developments that we recommend in Table 6. This provides further detail to complement the Roadmap diagram of Figure 57.

Table 6	Gas Market Roadmap Table

		Period			
Dimension	**Aspect**	**Period to 2020**	**2021 to 2025**	**2026 to 2030**	**Beyond 2031**
Legal & Regulatory Framework	**Legal & Regulatory Documents**	• Gas Law as a Government Decree • Gas Industry Charter • Develop industry wide Technical & Safety Codes (based on international standards)	• Gas Market rules and • Gas Market Rules & Technical & Safety Code change process • Implement an open access regime for gas pipeline connection and transport	Refinements to Gas Market Rules and Technical & Safety Codes as required based on experience in operating the Gas Market	Refinements to Gas Market Rules and Technical & Safety Codes as required based on experience in operating the Gas Market
	Planning Framework	• Retain the status quo: PVN undertakes planning on behalf of the gas industry. • Supply and demand projections approach continues.	• Independent organisation becomes responsible for gas planning. • General enhancements to gas industry planning are introduced. • Use of economic cost-benefit evaluations and least cost planning to determine efficient investments. • Enhance integration between gas, electricity,	• Reorient Gas Industry planning to be "market-oriented". • Evaluate market benefits for different investment options. • Identify and publish opportunities for investments in Viet Nam's gas industry. • Improve transparency with publication of detailed information on assessments of market	

		Period			
Dimension	**Aspect**	**Period to 2020**	**2021 to 2025**	**2026 to 2030**	**Beyond 2031**
			industry, and other sectors. • Improve transparency with publication of detailed findings.	opportunities and information on Viet Nam's gas sector.	
Organisational Structure	**Governance Structure**	Establish a Gas Market Steering Committee (under MOIT)	• Establish an independent gas economic, technical and safety regulator(s) similar to the power industry's ERAV with responsibility and appropriate powers for industry monitoring, compliance and enforcement. • Implement independent and transparent consultation process for code technical and safety review and modification.	Opportunity to explore combining the electricity System and Market Operator (SMO) with the GSMO.	
	PVN Restructuring	• Non-oil and gas businesses separated from all oil and gas activity	• Mid-stream and down-stream gas business functions including particularly PVGas, separated from the	Depending on government policies and financial considerations, the downstream businesses	Depending on government policies and financial considerations, the downstream businesses

		Period			
Dimension	**Aspect**	**Period to 2020**	**2021 to 2025**	**2026 to 2030**	**Beyond 2031**
		• Technical regulation, market regulation and policy advice to GDE separated from any operational business unit. • Construction, Engineering and Technical Service Providers and associated functions moved into a separate business unit. • PVN functional separation and ring-fencing of GMSO, HP gas transmission, MP/LP distribution, marketing and sales. • Implement transparent and measurable KPIs and benchmarking measures	upstream oil and gas businesses and service providers. • Establish an independent gas economic, technical and safety regulator. • Gas management and system operations transferred to an independent agency.	could be considered for divestment.	could be considered for divestment.
Gas Market Development	**Economic Valuation of Natural Gas**	Economic valuation of natural gas framework			

		Period			
Dimension	**Aspect**	**Period to 2020**	**2021 to 2025**	**2026 to 2030**	**Beyond 2031**
		introduced as a precursor to a Gas Market. Step 1: • Develop an approve economic valuation methodology • Apply to integrated economic resource and project planning and resource allocation Step 2: • Apply economic gas valuation methodology into gas development planning			
	Pricing and contractual mechanisms	No changes to existing gas contracts or gas trading mechanisms	• Establish independent gas economic and technical regulator (GRAV) • Gas market rules and open access tariff regime promulgated	• Step 1: Introduction and trial of gas trading • Step 2: Full commercial operation of Gas Market	Assess / review Gas market outcomes and contemplate the feasibility and need for a retail gas market

		Period			
Dimension	**Aspect**	**Period to 2020**	**2021 to 2025**	**2026 to 2030**	**Beyond 2031**
			• The establishment of a bulletin board to publish market data • Remove restrictions and permit flexibility in gas contracts • Gas system and market operations transferred to an independent agency		
Infrastructure	**Major Infrastructure Developments**	• No significant developments	• During this period, under the GMP of 2017: • Block B and Ca Voi Xanh are planned to come into production; and • Viet Nam will commence first LNG imports		
	Supporting developments for Gas Market		• The necessary investments in ICT infrastructure to enable the Gas Market to operate according to the Gas Market Design and Gas Market Rules have been made	• Further LNG developments • Production from existing fields start to decline • New yet to find sources of domestic gas may be brought into production	• Further LNG developments • Production existing fields as of 2017 continues to decline • New yet to find sources of domestic gas may be brought into production

		Period			
Dimension	**Aspect**	**Period to 2020**	**2021 to 2025**	**2026 to 2030**	**Beyond 2031**
			• Routine publication of key information on gas market operations for industry • In the electricity industry, the System and Market Operator (SMO) is planned to undergo a number of steps towards becoming independent from EVN.		

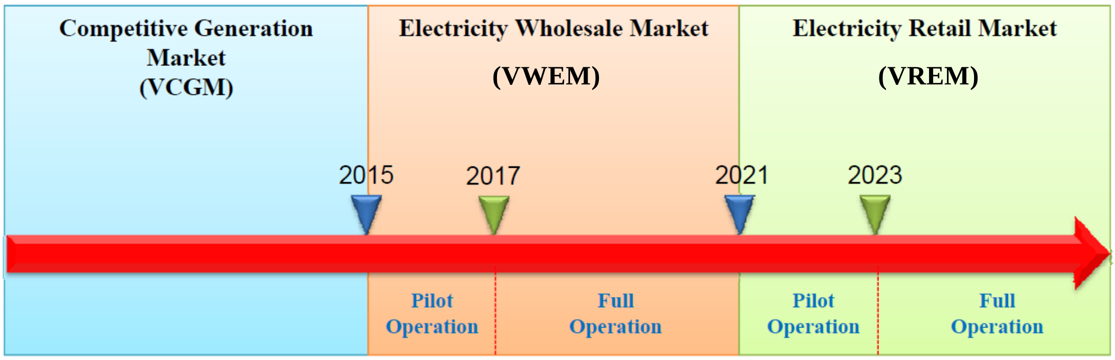
12.5 Synchronisation with Electricity Sector

The present Electricity Industry Reforms Roadmap for implementation of the competitive power market was based on a review and revision of an earlier Roadmap promulgated in 2006. The current Roadmap is set out in the PM's Decision No. 63-2013-QD-TTg was promulgated in 2013. As illustrated in Figure 71, the current Electricity Roadmap is a 20 year implementation plan for gradually transforming Viet Nam's electricity industry into one that allows for competitive wholesale and retail electricity markets. This defines a time line for transitioning between three major stages of reform:

- Viet Nam Competitive Generation Market (VCGM), which commenced full commercial operation in July 2012;
- Viet Nam Wholesale Electricity Market (VWEM), and
- Viet Nam Retail Electricity Market (VREM).

Each stage commences with a pilot period, with a number of constraints defined, which is subsequently followed by a "full operation" period. A detailed discussion of Viet Nam's electricity industry reforms experience is provided in Appendix G.

Figure 58 Electricity Industry Reform Roadmap (2013)



Source: ERAV

The generation sector of Viet Nam's electricity industry is a major consumer of natural gas in the country therefore coordination between reforms in electricity and gas is important, particularly in relation to electricity pricing and gas pricing frameworks. The Electricity Industry Reforms Roadmap has put Viet Nam on a course of gradually becoming more interlinked with international energy pricing, a consequence of reaching the limits of domestic resources and lower cost resources that can be deployed power generation. Starting from 2019, Viet Nam Wholesale Electricity Market (VWEM) with a later stage being VREM. This places pressure on the electricity industry to have wholesale and retail electricity prices that are more reflective of international prices. By the time that a Gas Market commencing pilot and then full commercial operation at the start of the 2026-30 period is complete, the VWEM will have been in full operation least 5 years and should be delivering cost reflective price outcomes.

12.6 Challenges and Priorities

12.6.1 Major challenges

The Gas Market Roadmap that we have presented is not without its challenges. As discussed in section 12.2, there are numerous actions that need to be resolved within a short period of time in order to ensure that the transition steps defined in the Roadmap can be completed in a timely manner. The following are key challenges that will need to be overcome:

- Direction of the government to retain the status quo to 2025 sets a precedent for no action until after 2025. However, given the urgency of developments in Viet Nam's gas sector and the fact that there are many no regrets improvements, we view this pace to be too slow.
- Restructuring PVN, a wholly government owned entity that has its monopoly status for all oil and gas activities in Viet Nam written into the law in its Charter. Experience suggests that changes are likely to be resisted.
- Change in culture away from a centrally planned and managed gas industry towards one that has unbundled midstream monopolies into a regulated transport function and merchant gas supply function.
- Ensuring developments in the electricity sector and gas sector are coordinated. The Gas Market Roadmap and Electricity Industry Reforms Roadmap have some dependencies – particularly in relation to allowing prices to gradually become cost reflective as Viet Nam's electricity industry becomes increasingly linked to global energy prices.
- Transition away from pricing and supply approaches that provide some industries with preferential treatment, for example, the petrochemical industry.
- Introducing flexibility in existing contracts. We have suggested that buyers and sellers seek to mutually agree to changes that would introduce flexibility in the contracts, but there is the risk that this could not deliver a desirable outcome.
- Introducing a framework for economic valuation of natural gas and the shift away from a focus on gas pricing levels.
- Ensuring that MOIT is sufficient well-resourced with staff capable of progressing and oversighting the implementation of the Gas Market Roadmap.

The transition towards a liberalised gas industry in Viet Nam faces a number of risks that will need to be carefully mitigated. Part of the reason for suggesting the GMSC to oversee the implementation of the Gas Roadmap for it to operate as vehicle to identify and mitigate risks. Further discussion of risks and possible mitigation measures, including international experience, are given in Appendix D.

12.6.2 Immediate priorities to 2020

The immediate priorities to 2020 are as follows:

- Gas Market Roadmap promulgated as PM Decision is critical;
- MOIT to develop legal framework to create certainty to the industry and potential investors. This involves:

- setting up industry-wide Technical, Safety and Environmental Code(s);
- Promulgating the Gas Law as a Government Decree;
- Promulgating the Gas Industry Charter as a Government Decree (and to supersede the PVN Charter);

- Making immediate progress in relation to separation of PVN's business units and ring-fencing them as a major precondition for commencing a Gas Market; and
- Introducing an enhanced and standardised economic valuation of natural gas framework to improve the quality of decision-making.

Appendix A Key Gas Infrastructure

Table 7 Summary of Key Gas Infrastructure in Viet Nam

Infrastructure	Description
Cuu Long basin pipelines system	Commenced operation in 1995, the Banh Ho – Dinh Co – Phu My gas transmission system collects and supplies natural gas from the Cuu Long basin's gas fields such as Bach Ho, Rang Dong-Phuong Dong, Ca Ngu Vang, Su Tu Den and others. This pipeline system is owned by PVN and operated by the subsidiary PVGas. The initial capacity was around 1.5 Bcm/y, which had then been extended to 2.0 Bcm/y in 2001 and 2.2 Bcm/y in 2006. Natural gas from the Cuu Long basin is supplied to the Phu My Fertiliser Plant and some other industrial users; the remaining is used for EVN gas fired power stations in the Phu My complex including Phu My 2.1, Phu My 2.1 Extension, Phu My 4 and Ba Ria Power Plant. The total pipes length (before the Phu My GDC) is nearly 300 km, although the actual gas transport flow has been reduced to 4 Mmcmd (~1.42 Bcm/y) due to declining productions from Bach Ho field.
Nam Con Son basin pipelines system (NCS1)	The Nam Con Son-Dinh Co-Phu My (NCS1) pipelines system is Viet Nam's largest modern integrated gas-to-power project delivering gas from the NCS basin's offshore fields of Lan Tay, Lan Do, Rong Doi and others, to the Phu My GDC via a 460 km subsea pipeline. The power stations supplied with gas are: EVN owned plants Phu My 1, Phu My 2-1, Phu My 2.1 Extension, Phu My 4 and Ba Ria; BOT plants Phu My 2.2 and Phu My 3; and PV Power plants Nhon Trach 1 and Nhon Trach 2 (via Phu My-Nhon Trach-Hiep Phuoc onshore pipeline). The project started operation in late 2002 as a consortium comprising PVN (51%), BP (32.67%) and ConocoPhilips (16.33%). BP operated the pipeline from its establishment in 2003 until 2008, when it was transferred to PVN. The main pipe has a maximum transmission capacity of 21 Mmcmd and currently loaded at stable levels of around 19 Mmcmd.
Nam Con Son 2 pipelines system (NCS2)	The NCS2 pipelines project was approved in 2011 and and would be constructed in two stages. Stage 1 was completed in May 2016 involving the construction of 151 km pipelines for collecting gas from Dai Hung and Thien Ung fields in the NCS basin and transporting the gas to the Bach Ho compressing station (BK4A) for connection with the Bach Ho - Dinh Co pipeline. Stage 2 would involve extending the NCS2 pipeline directly to the Phu My GDC.
Phu My-Nhon Trach-Hiep Phuoc onshore pipeline	The Phu My-Nhon Trach-Hiep Phuoc pipeline is an (onshore) pipeline system to supply gas from the Phu My GDC to Hiep Phuoc and Nhon Trach power stations and consumers in the Ho Chi Minh City area. It became operational in April 2008, has 71 km in length and a capacity of 2 Bcm/y (stage 1), expanded to 3.8 Bcm/y in stage 2.

Infrastructure	Description
PM3-Ca Mau pipeline	Commissioned in 2007, the PM3-CAA Mau pipeline supplies gas from PM3-CAA and Cai Nuoc fields (current), and blocks 46, 50 & 51 (in future) to the Ca Mau power – fertiliser complex that includes the 1500 MW Ca Mau power stations 1 & 2 and Ca Mau fertiliser plant. The pipeline was completed under the PM3 Commercial Arrangement Area (CAA), funded completely by PVN with PVGas being the operator. The gas transmission system comprises 298 km offshore pipelines and 27 km onshore pipelines for connecting with the Ca Mau GDC; its current transmission capacity is around 2.2 Bcm/y.
Ham Rong – Thai Binh pipelines system	Stage 1 of this project commenced operations in August 2015. It comprises 24 km pipelines, collecting natural gas extracted from the current Thai Binh and Ham Rong fields, and other potential fields in the Northern region. The current transmission capacity is 1.465 Mmcmd, which is expected to be increase in Stage 2 from 2019.

Appendix B GMP Development Options – Further Details

This appendix provides more detailed information on gas development options identified in the Draft Gas Master Plan (GMP).

B.1 Further Details on Domestic Fields

B.1.1 Northern Region

The gas fields being planned for production have complex geological conditions and / or are small marginal fields, with low gas quality (high concentration of CO_2, H_2S and heavy metals). Under the base case scenario, in the 2016-2025 period production from Thai Binh and Ham Rong fields would be stable at 0.20 – 0.28 bcm / year for supply to small, dispersedly located industrial users. Under the optimistic scenario, from 2020 onward, production from Ham Rong Nam – 1X, Hong Long – Bach Long – Hac Long fields is forecasted to peak at 0.31 bcm / year, and from 2029 blocks 102&106 and 103&107 are projected to come into operation, adding a maximum of 1.5 bcm per year (from 2033). However, these forecast are subject to uncertainty and would require continued reviews.

B.1.2 Central Region

Gas supply in this region mostly comes from the Ca Voi Xanh field at block 117-119. This field will deliver gas to in-land from 2023 expectedly, at a maximum level of 6.2 bcm / year (net hydrocarbon). This will then facilitate the establishment and development of the gas market and downstream gas distribution network in the region. In addition, additional supply is expected from the Bao Vang field at approximately 0.6 bcm / year from after 2023 and from potential fields in lots 105-110 & 111-113 (commenced in 2030-31) at a maximum total production of 2.4 bcm/ year in 2033.

B.1.3 South East Region

During 2016-2018, natural gas supply in the region is expected to remain stable at 8-9 bcm / year, which is adequate for meeting the forecasted market demand. The newly constructed Nam Con Son (NCS) 2 – Phase 1 project will deliver additional gas to maintain the transportation capacity of the Bach Ho – Dinh Co pipeline at a 2 bcm / year level while the existing NCS1 system is expected to operate at a capacity of 7 bcm / year.

From after 2019 the Su Tu Trang field is projected to be fully developed producing 2.5 bcm / year. In combination with added supply from the new Sao Vang, Dai Nguyet fields, this would make the total amount of natural gas delivered to shore reach 9.1-9.7 bcm / year toward 2014 under the base case scenario, or 9.8-12.8 bcm / year under the optimistic scenario. Gas collection and transport infrastructure projects planned for this period includes construction of the NCS2-Phase 2 pipeline and the second gas processing plant (GPP).

From 2025 onward, gas supply is forecasted to decline gradually, from 8.16 bcm in 2025 to 1.33 bcm in 2035 under the base case scenario. The GMP has recommended commencing production of the potential fields in the region, to help maintain yearly delivery at 13.16 bcm until 2027, and a reduced level of 8.93 bcm by 2035. In addition, it is also planned that new gas fields in the Phu Khanh and Tu Chinh – Vung May basins will be connected with the Cuu Long and NCS pipelines system to deliver this supplementary gas for meeting the demand of the South East market.

B.1.4 South West region

Supply from PM3 block, Cai Nuoc field and block 46 are projected to maintain stable levels between 1.75 - 2.28 bcm per year during 2015-2020, but decline by 2031. In the meantime, PVGas has planned to increase the current production capacity to 2.35-2.40 bcm / year (8% CO2) from June 2016 to ensure the demand of the Ca Mau gas-power-fertiliser complex is adequately met.

When in operation from 2020, gas deposits from blocks B, 48/95, 52/97 would provide stable supply at around 3.84 bcm / year (CO2 net) or 5,06 bcm / year (CO2 gross). The average proportion of inert gases is around 21% in a 20 years' period for gas users in Ca Mau, gas fired power plants in Kien Giang, O Mon Thermal Power Centre and other industrial users in Kien Giang and Can Tho.

B.2 LNG Imports

The GMP has scheduled first LNG imports to commence during 2019-2021, with approximately 0.59 MT / year of LNG delivered into the South East market to supplement the drop in production in this region. This will be followed by commencing LNG imports for the other three regions including South West (at Hon Khoai - Ca Mau) in 2022, Centre South (at Son My - Binh Thuan) in 2023 and North (at Hai Phong) in 2025. LNG yearly imported volumes are projected to increase from 1.06 MT in 2022 to 5.25 MT in 2025.

It has also been planned to further increase LNG imports in the following period, from 7.46 MT in 2026 to 11.05 MT in 2030 and 13.89 MT in 2035. According to the GMP, power producers in Son My and the South East regions are the main LNG users, consuming 10.52 MT in 2035, which accounts for 75.7% of the total import volume.

Potential LNG exporters under consideration include Middle East countries, Russia, Australia and China, in part for meeting the Northern region's demand.

B.3 Downstream Gas Market under GMP

In 2015, Viet Nam's gas consumption market size reached 10.4 bcm, 83% of which was accounted for the power generation sector, 11% consumed by the fertilisers and 6% - other industrial users. According to the GMP, in the 2016-2025 period and beyond until 2035, the market size is expected to grow significantly, to 21 bcm / year under the base case scenario and 26 bcm / year under the optimistic scenario. There would be changes in the consumption mix by sector with the power industry's share declining to around 72.3% while fertilisers and chemical users' proportion increasing to 21.2% and other industrial gas consumption remaining stable at 6.5%.

The GMP has identified future development features for each regional retail gas market in Viet Nam as follows:

- **ern Region:** The market demand is expectedly served by the gas supply from the Bac Song Hong basin, notably the Thai Binh and Hong Long – Hac Long – Bach Long gas fields. The region's market consumption has been estimated to be around 0.25 bcm and 0.5 bcm by 2025 under the base case scenario and the optimistic scenario accordingly. Beyond 2025, additional supply will be required for the Hai Phong 3 power plant, consuming around 1.24 bcm / year. This demand would be met with imported LNG, at 8.89 MT approximately.
- **Central Region:** Demand will be served with gas supply from the Nam Song Hong and Phu Khanh basins, notably the planned Ca Voi Xanh and Bao Vang fields. Main gas users include two gas fired power plants consuming around 3.72 bcm / year (Dung Quat BOT and Mien Trung CCGT 1 & 2 capacity 750 MW each), the refinery industry requiring 1.21 bcm / year (net HC) and other industrial gas users intaking 0.27 bcm per year. It has been also proposed that if the planned refinery project becomes unfeasible and does not go ahead, the redundant supply will be taken by a new Mien Trung CCGT 3 power plant capacity 750 MW; never the less, if gas production reaches 900 mmscd, it will be sufficient to serve the demand of both the proposed refining plant and the CCGT power plant.
- **South East Region:** This region's gas market is correspondingly served from the Cuu Long, Nam Con Son and in future Tu Chinh – Vung May basins. Main users remain the CCGT power plants requiring 6.62 bcm of gas each year, expected from 2024 onward, the power plants in the Bar Ria – Phu My region will switch to using imported LNG. Other users are fertilisers, chemical and industrial plants (including existing and new consumers)
- **South West Region:** This market is served by gas from the Ma Lai – Tho Chu basin. Gas intakers include the existing users in the Ca Mau region and new consumers in Can Tho and Kien Giang. It is estimated that the CCGT power plants (existing and new) will require around 5.36 bcm / year; fertilisers and other users would be consuming 0.69 bcm per year in average.

B.4 Key Offshore Gas Pipeline Developments

B.4.1 Summary of gas pipeline development options

The GMP has proposed construction of offshore main (backbone) pipeline projects in each region and that has been phased in two periods, from 2016 to 2025 and from 2026 to 2035. A summary is given in Table 8 and we discuss the details of each of these periods in the subsections that follow.

Table 8 Summary of Proposed Main Gas Pipelines

Location	Main Pipeline	Year of Commissioning	Capacity (m^3/y)	Length (km)
Northern Region				
Onshore	Ham Rong to Thai Binh (stage 2)	2018-2020	0,5	53
	Blocks 102/106 & 103/107 to Tien Hai LFS	2030-2035	2	80-100
Off-shore	Tien Hai LFS to Thai Binh regions	2032	1.5 - 2	6
	Northern LNG Terminal to Northern CCGT	2025-2030	2	15-20
Central Region				
Onshore	Ca Voi Xanh to Quang Nam / Quang Ngai	2023	9-11	85-95
	Bao Vang to Quang Tri	2023	2-3	120
Off-shore	LFS (for CVX gas) to GTP/GPP	2023	9-11	5-10
	GTP to Quảng Nam / Quang Ngai CCGT Complex	2023	4	25
	GPP to Dung Quat thermal power plant	2023	2-3	25-35
	Quang Tri GDC to Quang Tri CCGT #1, #2	2033	1.5	10
South East Region				
Onshore	Nam Con Son 2 (stage 2): KP 207 to LFS	2019	7	117
	Compressor station at Sao Vang – Dai Nguyet	2021-2022	3.5	
	Phu Khanh Basin to Binh Thuan / Ba Ria - Vung Tau	2030-2035	3	250
	Tu Chinh – Vung Mai Basin to NCS	2030-2035	2	150
Off-shore	Long Hai LFS to GPP2	2019	7	9
	GPP2 to Phu My GDC	2019	7	30
	GPP2 to Long Son Refinery (for Ethane)	2019	0.3 MT	23
South West Region				
Onshore	Block B to O Mon	2020	6.4	292
	Block B to PM3 – Ca Mau (KP209)	2020	2.4	37

Location	Main Pipeline	Year of Commissioning	Capacity (m^3/y)	Length (km)
Off-shore	Pipeline connecting LFS and Kien Giang GDS	2020	6.4	30
	Kien Giang GDS to O Mon GDC	2020	6.4	72

B.4.2 2016-25 period

- *Northern Region:* The phase 2 of the Thai Binh - Ham Rong pipelines system will be implemented to commence collecting gas from the Ham Rong field in 2018-2010, with maximum capacity of 0.5 bcm / year. The pipelines built from floating production, storage and offloading (FPSO) Ham Rong fields will be connected to the Thai Binh – Tien Hai pipeline.
- *Central Region:* A high pressure pipeline will be constructed for transporting gas from the Ca Voi Xanh field to Quang Nam / Quang Ngai shores, capacity of 9-11 bcm / year and in operation from 2023. Construction is also planned for another pipeline to transport gas from the Bao Vang field to Quang Tri, capacity 2-3 bcm / year, with the project phase 1 beginning the operation form 2023 delivering 0.6-1 bcm / year.
- *South East Region:* Construction of a new compressor station has been planned in the Bach Ho region to take the supply of gaslift from the Cuu Long basin with proposed capacity of 1.2 bcm / year (equivalent to 3.4 mmscmd, stage 1 will install one unit at capacity 1.7 mmscmd for the supply from Tho Trang, Vom Bac and MSP fields, and phase 2 will add another unit with the same capacity to intake the gas from SV/DN). The 117 km NCS2 pipeline - phase 2 connecting KP207 to shore has been scheduled for operation from 2019.
- *South West region:* The construction of the block B – O Mon pipeline at capacity 6.4 bcm / year is planned to complete by 2020 to collect gas from blocks B&48/95, 52/97 fields.

B.4.3 2026-35 period

- *Northern Region:* The GMP has recommended to conduct studies for construction of pipelines to transport gas from other potential fields located in blocks 102/106 & 103/107 to Tien Hai, with capacity around 2bcm / year, for operation after 2030.
- *Central Region:* Studies have been recommended for implementation of phase 2 to collect gas from potential fields located in blocks 105-110 and 111-113, connected into the Bao Vang – Quang Tri pipeline, for operation after 2030.
- *South East Region:* Studies have been recommended for construction of: i) main pipelines for collecting gas supplied from blocks 129 – 132, Tu Chinh – Vung May basin and connected with the NCS2 pipeline; ii) main pipelines for collecting gas supplied from blocks 133-136, Tu Chinh – Vung Mai basin and connected with the NCS1 pipeline; iii) pipelines connecting Phu Khanh basin with Binh Thuan / Ba Ria Vung Tau; and iv) importing pipelines connecting the TRANS ASIAN pipelines with NCS1/NCS2 pipelines.

B.5 Gas Collecting and Inter-Field Pipeline Developments

The GMP has also proposed developments of pipeline projects for connecting new gas fields in production with the main backbone transportation pipelines. These projects are summarised as follows.

B.5.1 2016-25 period

- *South East Region:*
  - Cuu Long Basin: Pipeline networks will be developed for collecting and delivering natural gas and associated gas from Kinh Ngu Trang, Kinh Ngu Trang Nam, Song Ngu, Lead A (block 09-2/9) gas fields to the Rang Dong Compressor Station. Another construction is planned for the pipeline connecting the Su Tu Trang field with the NCS2-phase 2 main pipeline with capacity 3 bcm / year.
  - Nam Con Son Basin: Construction is planned for a pipeline to collect and deliver associated gas from Ca Rong Do field to Lan Tay (NCS1 pipeline extension) for operation from 2019, and a pipeline for gas collection from Dai Nguyet and Sao Vang fields, to be connected with NCS1 and NCS2 pipelines from 2021/2022.
- *South West Region:* Projects planned in the Ma Lai – Tho Chu basin include construction of the pipelines interconnecting Hoa Mai, Dam Doi and Khanh My fields, development of the pipelines to connect the Nam Du, U Minh/Minh Hai and Khanh My fields with BOD WHP / BOA CPP, to deliver gas to shore via the PM3 – Ca Mau pipeline from 2020. In addition, another pipeline connecting the Ac Quy/Kim Long – Ca Voi fields with the block B pipeline would also be built by from 2020.

B.5.2 2026-35 period

- *Northern Region:* The GMP has recommended more studies into potential gas deposits and construction of pipelines for gas collection from potential fields such as Hong Long, Hac Long, Bach Long, Dia Long etc., within blocks 102/106 & 103/107, and pipelines to collect gas from other potential fields in these blocks but located further away from the mentioned fields. These pipelines are to be connected with the Ham Rong - Thai Binh main pipelines after 2032.
- *Central Region:* Studies are recommended on construction of pipelines for collecting gas from gas fields located in blocks 105-110 and 111-113, to be connected to the Bao Vang – Quang Tri main pipe after 2030; pipelines for gas collection from potential fields in block 115-119 and connecting with the Ca Voi Xanh main pipe after 2035.
- *South East Region:* Construction is suggested for i) pipelines collecting gas from Doi Nau, Ha Ma Xam fields to deliver to the Rong / Doi Moi compressor station and then to Bach Ho – Dinh Co main pipeline, ii) pipelines connecting the Rong Vi Dai, 12C, Thien Nga, Ca Kiem Den, block 06-1, 05-2 & 05-3, 11-2 gas fields with the NCS1 pipeline, and iii) pipelines collecting gas from Than Nong, lots 04-1, 04-2, 04-3, 05-1 into the NCS2 pipeline.
- *South West Region:* Studies are suggested into construction of the gas importing pipeline to import gas from Asian to PM3 – Ca Mau in 2030, to provide additional supply for addressing gas shortages otherwise expected in the region.

B.6 Key Onshore Gas Pipeline Developments

B.6.1 2016-25 period

The GMP has identified the following major onshore pipeline projects for construction from 2016 to 2025.

- *Central Region:* Constructing the pipeline to deliver LFS to the GTP/GPP capacity 9-11 bcm / year and the pipeline from the GTP/GPP to the CCGT power plants complex in Quang Nam/Quang Ngai, capacity 6 bcm / year, for operation from 2023.
- *South East Region:* Constructing the pipeline to deliver LFS to the GPP2 capacity 7 bcm / year and the pipeline from the GPP2 to the Phu My Gas Distribution Centre (GDC), capacity 6.5 bcm / year, and construction of the pipeline for Ethane transportation from the Ethane separation factory to Long Son Refinery, capacity 300,000 tonnes / year in 2019.
- *South West Region:* Constructing the pipeline between Kien Giang and O Mon, capacity 3.4 bcm / year, operating from 2020 to provide gas for the O Mon Thermal Power Centre; the pipeline supplying gas from Kien Giang GDC to Kien Giang Power Centre, capacity 2 bcm / year, in operation from 2020.

B.7 Low Pressure Gas Pipelines

The GMP has not proposed detailed projects with respect to low pressure gas pipelines but recommended on development and enhancement of the distributing gas networks to ensure adequate gas supply for all industrial, residential and commercial end users.

B.8 Gas Processing Plants (GPPs)

B.8.1 Summary of gas processing plants

A summary of proposed gas processing plants is provided in Table 9. We provide further details in the subsection that follows.

Table 9 Proposed Gas Processing Plants

Location	GPP	Year of Commissioning	Capacity (m^3/y)
Central	Quang Tri GPP	2018-2020	2-3
South East	Dinh Co GPP (GPP2)	2019	7
	Ethane separation plant (integrated with GPP2)	2019	2
South West	Ca Mau GPP	2016	2.2
	Kien Giang GPP	2020-2015	6.4

B.8.2 2016-25 period

- Central Region: Studies are suggested into the construction of a GTP/GPP capacity 9-11 bcm / year to intake the gas supply from Ca Voi Xanh in 2023.

- South East Region: Construction has been planned for the GPP2 in Dinh Co, capacity 3.5 bcm per year, the Ethane separation factory to process the gas delivered on the NCS2 pipeline, and the LNG/CNG factory jointly invested by PVN and Gazprom.
- South West Region: Construction is underway for the Ca Mau GPP located in Khanh An Industrial Park near the Ca Mau GDC, capacity 2.2 bcm / year, expected operation from 2017 for processing gas supplied from the PM3-CAA field. In addition, the GMP has also recommended on a feasibility study and expected construction of a GPP in Kien Giang, capacity 6.4 bcm / year, to intake gas supplied from block B for Ethane, LPG and Condensate separation.

B.9 LNG Import and Regasification Terminal

B.9.1 2016-25 period

In line with the plan for LNG imports, construction of the first LNG import terminal in Thi Vai (South East region), capacity 1 MT / year has been scheduled for completion in 2019-2020, followed by Hon Khoai LNG terminal with capacity 1 MT / year for phase 1 (2022), Son My terminal (in Binh Thuan) capacity 3 MT / year for phase 1 (2023) and Cat Hai terminal capacity 1 MT / year (2025).

B.9.2 2026-35 period

It is foreseen in the GMP that the capacity of Son My LNG Terminal would be expanded by 5 MT / year: 3 MT / year during 2027-2030 and 2 MT / year during 2031-2035. Cat Hai and Hon Khoai terminals will also be considered for expansion by an additional capacity of 1-3 MT/ year after 2035. Depending on actual demand, a new My Giang terminal (in Khanh Hoa) with capacity 3 MT / year could also be constructed.

Appendix C Economic Costing: Case Study and Assessment

C.1 Application of the valuation methodology to current technology and fuel costs

A cost model was utilised for coal ($US60/ton & $US100/ton) and gas ($US7/MMBtu and $US10/MMBtu) fuel supply and technology scenarios. International reference data[42] was used for this analysis. The base case input assumptions are shown in Table 10.

Table 10 Base Case Input Assumptions

		Base Gas @$7.00	Base Gas @$10.00	Base Coal @$60/t	Base Coal @$100/t
Fuel Price	$/ton			60	100
Fuel Price	$/MMBtu	7	10	2.5	4.2
Discount Rate	%	11%	11%	11%	11%
Term	Years	15	15	15	15
Capacity Factor	%	85%	85%	85%	85%
Heat Rate	Btu/kWh	6743	6743	8124	8124
Efficiency	%	51%	51%	42%	42%
Unit Capex	$/kW	819	819	2160	2160
Fixed O&M	$/kW/yr	7.5	7.5	37.9	37.9
Variable O&M	$/MWh	5.3	5.3	3.0	3.0
CO2 Emissions	kg/GJ	57	57	91	91

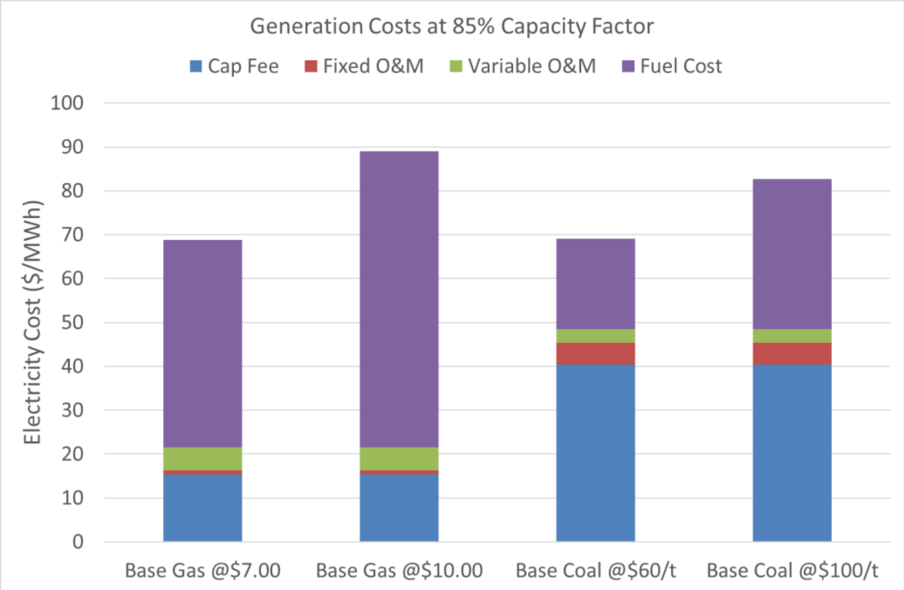
The unit capex cost reflects supercritical pulverised coal technology. This is mature technology and a reasonable policy response to meet carbon emission targets. Generation technology assets have long asset lives, exceeding 25 years. However, the economic return on capital for this analysis is assessed conservatively over a shorter 15-year period.

C.2 Base Case Model

An estimate of the total electricity cost for each gas and coal scenario was obtained using the base case assumptions in our economic model. For an 85% capacity factor scenario the amortised capital cost, fixed and variable operation and maintenance (O&M) costs, fuel and total costs are compared in Figure 59.

[42] 05 0126 https://www.aemo.com.au/-/media/Files/PDF/Fuel_and_Technology_Cost_Review_Report_ACIL_Allen.pdf

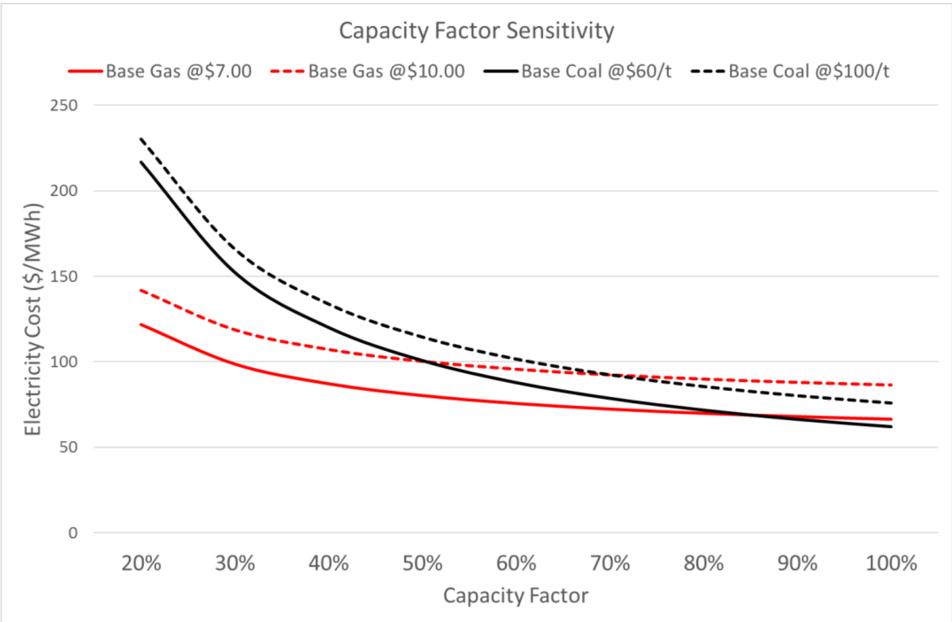
Figure 59 Base Case - Total Electricity Cost for Coal and Gas Scenarios



C.3 Sensitivity to Capacity Factor

For a full range of capacity factor scenarios, the total cost of electricity supply is compared for the base case coal and gas developments in Figure 60.

Figure 60 Total Electricity Costs for Coal and Gas at Different Capacity Factors

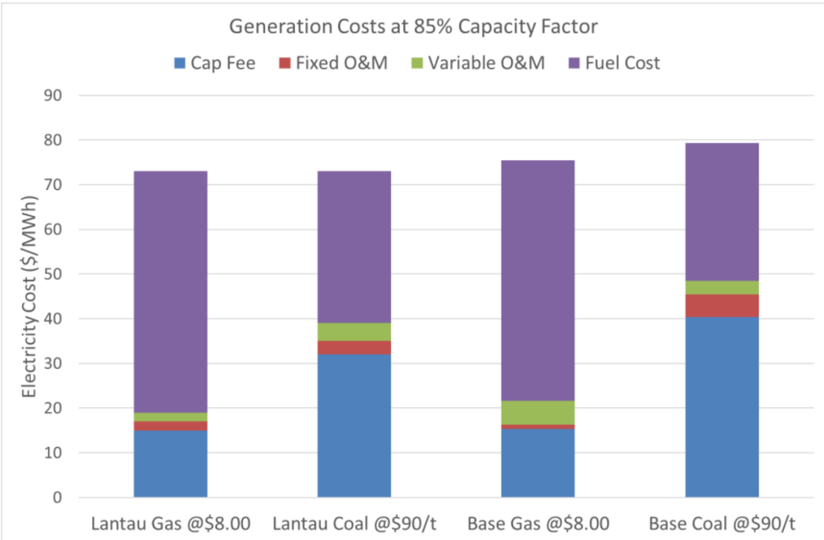


C.4 Model Comparison

The Base case model is compared to Lantau 2014[43] published analysis in Figure 61. The principal differences are the differences compared to Lantau's O&M assumptions, and Lantau's capital cost and efficiency assumptions for sub-critical coal technology compared with super-critical coal technology in our Base case model.

While the components differ, the aggregate difference in outcomes is relatively small and it is unlikely that the differences would lead to substantially different resource allocation preferences.

Figure 61 Base Case comparison to Lantau 2014 published analysis



C.5 Comparison of well head and LNG supplied estimates

A gas well head and LNG delivered price were estimated for the Base case and Lantau models from the results. These are shown in Figure 62. While these comparisons do not represent comprehensive resource assessments, they are indicative of an unadjusted lower bound economic value of gas.

[43] 00 0006 Comparative Economic Analysis of Coal & Gas in Viet Nam - Lantau 2014

Figure 62 Implied Gas well head and LNG delivered price for Base Gas, Base LNG, Lantau 2014[44]

Comparisons	Base Coal	Base Gas	Base LNG	Lantau Coal	Lantau Gas	Lantau LNG
Coal Cost $/ton	90			90		
Capacity Charge $/MWh	40.3	15.3	15.3	32	15	15
O&M $/MWh	8.1	6.3	6.3	7	4	4
Fuel Cost $/MWh	30.9			33		
Total $/MWh	**79.3**	Less **21.6**	**21.6**	**73**	Less **19**	**19**
Implied Net Economic Gas Value $/MWh		57.7	57.7		54	54
Implied Net Economic Gas Value $/MMBtu		8.6	8.6		8.0	8.0
Less: terminal			1.6			1.6
Less: shipping			0.4			0.4
Less: transport[30]		1.7			1.7	
Implied Well Head Value $/MMBtu		6.9	6.6		6.3	6.0

C.6 Potential Model Considerations and Adjustments to Economic Gas Net-back Valuation

The analysis provided is not a comprehensive resource development model for specific gas and power station developments. As noted in Section 8.3, the limitations of the model include factors that require adjustment to the model itself or relate to other policy and fiscal economic adjustments that the Viet Nam government may consider in developing gas resource pricing.

The minimum "lower bound" economic value of gas is the unadjusted heating value of gas as assessed. An upper bound value of gas may include adjustments for pricing policy considerations and targeted re-fiscal re-allocation. For illustrative purposes Figure 63 below provides the World Bank 2010 approach to such an adjustment.

Figure 63 Heating Value vs. Shadow Pricing $/MMbtu (illustrative purposes only[45])

(1) Straight Heating Value Price		(2) Shadow Price: with adjustments to reflect "value" not included in Column 1	
		Heating value price	**5.60**
		Plus:	
		Government take:	1.33
		Security premium	0.03
		Net of carbon emissions	
		Compared to coal	0.47
Value of natural gas delivered to the power plant:	**5.6**	Equals:	
		Shadow price	**7.43**

[44] Lantau 2014 did not assess a value for LNG. Lantau LNG is implied from Lantau 2014 Gas assessment.
[45] 00 008 Viet Nam Gas Sector Development Framework ESMAP January 2010 see page 63

Appendix D Case Studies: Implementation Risks for Gas Sector Reforms

This appendix provides a summary of the risks to Roadmap implementation drawn from the World Bank ESMAP study titled 'Vietnam Gas Sector Development Framework" in 2010.

D.1 Institutional change relating to the gas sector in national energy planning

Risk: The existing, probably seriously under-resourced institutional structure has trouble in adapting and makes some mistakes. Modern regulation of gas natural monopolies is a new field of activity for the GoV and there as well, mistakes will be made.

Response: There is some lead-time available before major policy changes need to be finalized. This time must be used to properly resource this activity, to train staff (sometimes abroad) and to exercise them in their new roles. The cost of properly resourcing this activity is small in relation to the efficiencies and other macro benefits that gas sector reform can yield. Nevertheless, policy and operational mistakes may occur. Timely mid-course corrections can be made if the Ministry's policy unit's monitoring is effective and its subsequent advice is properly directed. As to regulation of natural monopolies in the gas sector, there is much international experience to draw on and if ERAV is expanded and mandated, that aspect of gas regulation will be in good hands given the experience which, by then, ERAV will have accumulated in dealing with electric power natural monopolies.

International example: In the early 1990's, with World Bank encouragement, Argentina largely privatized and liberalized its electricity and gas sectors. In regard to gas, the state monopoly T&D company was split up and privatized, modern regulation of network natural monopolies was introduced, producer-seller competition was facilitated and a functioning wholesale gas market was successfully created. These changes were accomplished in a country with a very long history of state intervention in the energy sector (the state oil monopoly YPF was created before the First World War), by a bureaucracy that had no previous experience in creating the conditions in which market behaviours could initiate and flourish and with a governmental and legal tradition that previously had no place for the modern concept of transparent regulation of natural monopolies.

D.2 Gas Market Design

Risk: As a result of consolidations (producers selling assets to each other) or of the unexpected concentration of new supply in a few hands there is a weakening in seller competition and doubts arise as to whether there is still a condition of workable competition. Critics will then argue that this eliminates a basic underpinning of the wholesale competitive gas market.

Response: (1) It is generally accepted that even "weak competition" yields better resource allocation results than "good regulation" as it might be practiced by an National Oil Company (NOC) or by the new Regulator; (2) Replacing weak competition by reverting to the interim NOC led framework will do nothing to increase competition; (3) The bulk of the gas is going to be sold into power generation for the foreseeable future and in that use there will always be competing fuel sources, which will strongly constrain any market power of the gas sellers in relation to new generating capacity.

International example: The European Union (EU) has been seeking since 1998 to establish competitive gas markets in its jurisdiction (excluding the United Kingdom where a strongly competitive, liquid market already existed). With the cooperation of the EU, the IEA has just published a major study *Development of Competitive Gas Trading in Continental Europe—How to achieve workable competition in European gas markets?* (http://www.iea.org/textbase/papers/2008/gas_trading.pdf).

From this report two things are clear. First, that even after 10 years' effort, in many parts of the EU, workable competition has not been established. Second, that despite disappointments the goal is still being pursued because of the overall interest in increasing economic efficiency and ultimately lowering costs to final consumers. Two factors which have made the achievement of workable competition more difficult have been the tendency to consolidation among European utilities and the dominance in some parts of the EU of single supply sources such as Russia. Despite the great differences compared to Viet Nam in the history, size and supply-sourcing of the EU gas market, there are lessons here: sometimes, industry reacts to liberalization in ways that reduce competition (by consolidation); that the creation of workable competition is not easy; but that the rewards are considered to be so important that the goal is still worth pursuing. It is in this context that the EU is now proposing further measures to encourage competition.

One finding of the report relevant for Viet Nam is that "…real reform progress has been observed in markets with strong and independent regulatory authority." (IEA report, page 7) One objective is stated as follows: "In the present market context, significant shortfalls in investment throughout the value chain of the industry can be observed globally. The regulatory framework implemented in the European gas markets should be designed as "investment friendly", to allow costly and long term investments needed by the markets to be realized." (IEA report, page 89.)

D.3 Pricing Principles for Gas

Risk: The application of value pricing results in gas supply contracts with new generators containing prices which are much above the prices in the existing contracts (in the range of $2.1-3.22/MMBTU) and instead of escalating at a predetermined rate of below inflation (e.g. 2% for Nam Con Son) they will escalate with the price of competing fuels.

Response: It is not knowable what might eventuate from value pricing. The analysis is a complex one. Besides, there is the possibility, alluded to in the Report, of putting floors and ceilings on the fuel value prices. But fundamentally, competitive market pricing is what the NSED calls for and this is what value pricing will produce. Note that the rest of the economy—the very important oil fuels component for example--is fully related to international prices and price escalation. Prices of imported coal and imported LNG will also be at international levels and fluctuate with them. There is no good reason to insulate the gas-using consumer from these tendencies, on the contrary that would be harmful to sound inter-fuel competition.

International example: The under-pricing of gas is a major policy issue in a developing Asian country where gas is a critically important energy source and there are major supply uncertainties. An international consultant has recently addressed the problem in the following terms:

- *"In other words – current gas prices in --- are well below the opportunity cost of gas. In strict economic terms, gas should be priced relative to its opportunity cost – clearly this is not the case in --- as yet. Gas price relative to opportunity cost will enhance the upstream activities."*
- *"Pricing of gas is a sensitive issue in all developing countries across the world…. The government may take a view that subsidized gas and energy prices play an important role in contributing to strategic sectors…. While these views are valid considering the socioeconomic impact that gas plays in the economy, prices that do not reflect costs result in a financially non-viable gas value chain in --- and artificially inflated gas demand."*
- *"The need for domestic price reform is urgent given our long term analysis of the --- demand and supply scenario. Our analysis shows that --- faces a significant shortfall in gas supply in meeting the needs of its domestic market under all three cases of demand. Existing 2P gas reserves are only sufficient for the next seven years."*

It is not suggested that the situation in Viet Nam is as dire as the one being addressed in this consultant's report. However, the consultant's analysis is fundamentally applicable also for Viet Nam: gas pricing is a sensitive issue, but opportunity cost pricing is necessary in order to enhance supply.

D.4 Changed roles for the NOC (PVN) in the Gas Sector

Risk: The valuable role that the NOC has played in securing the Vietnamese public interest in the petroleum sector will be lost and the country will suffer.

Response: the NOC will continue as a very large enterprise active in many fields at home and abroad. Experience shows that where an NOC has had a monopoly position which is subsequently removed, competition results in more efficient operations. The NOC has built up huge experience and should be able to thrive in a competitive market. Not having to perform public interest related functions will free up the management to concentrate more fully on profitable functions to the benefit of its shareholder, the government and people of Viet Nam.

International example: The outstanding examples of NOCs that have been completely relieved of their sector-management, regulatory and social responsibilities and obligations and have become world-class energy businesses are of course the three Chinese NOCs—Sinopec, China National Offshore Oil Company and, the leader of the group, CNPC. The transformation that CNPC and its peers have achieved is remarkable and has projected it into the top tier of the international companies, in fact CNPC is reported in August 2009 to be the world's largest company in terms of stock market valuation. A glance through the 2007 Annual Report confirms this:

http://www.cnpc.com.cn/Resource/eng/img/07AnnualReport/2007PDF.pdf

The Chinese examples should create even greater confidence in the future of PetroViet Nam. There is no reason at all that PetroVietnam should not be able to follow the same course of transformation, although necessarily on a different scale.

D.5 Failure to Implement the Road Map

Risk: The most important elements of the road map are its recommendations for market design and for value pricing. But they did not originate with this Report and they are not unique to it. Thus: they are inherent in the NSED, they are highly relevant to the ongoing work on power market reform and they will no doubt be addressed in the NGMP. The present Report simply works out and applies key elements of the NSED to gas market design and pricing. Given that the absence of these elements is recognized as a serious "gap" in policy, given also the statements about competitive energy markets and energy price determination in the NSED, gas sector stakeholders of all kinds await implementation actions that should flow from the NSED. They likely expect actions of a type that are already under way in the power sector. Failure to now move on the road map would retard the development of the gas sector and of a competitive power market, discourage investments in the links of the gas chain and consequently have negative consequences for achievement of GoV policies such as modernization, industrialization, increased FDI and energy security.

Response: This potential problem is real and needs to be recognized and acted upon especially in the present times of global recession. The global energy industry may now be capital-limited rather than opportunity-limited. Investors will be seeking business environments where the "rules of the game" are clear and where pricing and fiscal regimes are internationally competitive. The road map, if acted upon, would help to create that kind of an environment for natural gas development in Viet Nam.

International examples: A good example of the positive effects of laying down sound policies in advance is the way in which the USA announced its policies for LNG imports in anticipation of the new wave of applications for LNG import terminals and then left policy implementation entirely to the regulator. This case has already been cited under heading 6.2 D on page 94. In regard to international competitiveness, South East Asian neighbours such as Malaysia and Thailand appear to offer predetermined policy conditions that include attractive pricing for new gas development. They appear to be well positioned to meet their growing gas requirements, in the case of Thailand by including imports in the supply mix. Timely policy action is particularly important in regard to gas supply: if R/P ratios decline to the point where supply is jeopardized, it is difficult to find policy measures that can quickly reverse the situation.

Appendix E Case Studies: Gas Pricing Mechanisms in Selected Asian Countries

This appendix provides a review of international experience for gas pricing approaches and has been drawn on the international experience in report "Vietnam: Issues in LNG and Natural Gas Pricing - Pricing options and lessons from other markets in Asia" conducted by ECA in 2014 for the World bank and MOIT.

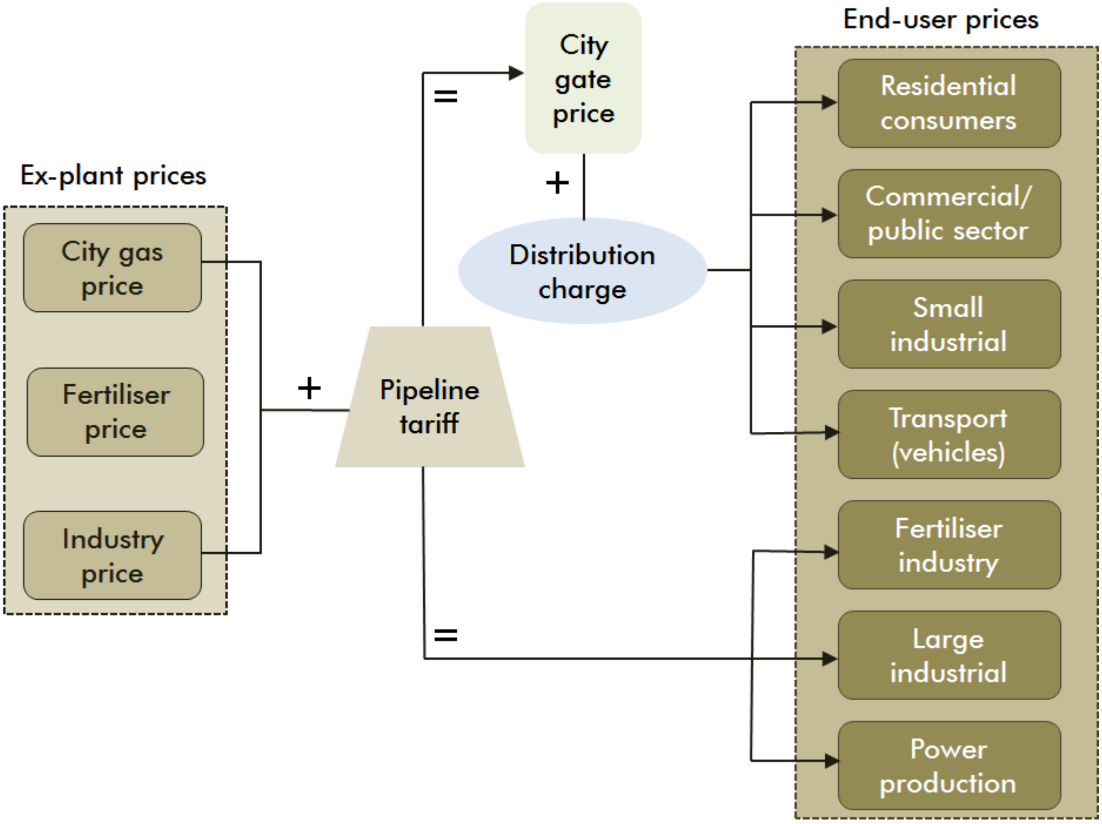
E.1 China Gas Price Approach

E.1.1 Gas pricing

Overview

Until recently, China's pricing regime (particularly for domestically produced gas) was based on a 'cost-plus' methodology with prices set for the different elements along the gas value chain and differentiated by end user according to the government's priorities and gas utilisation policy. The framework is depicted diagrammatically in Figure 64. As shown, this pricing regime essentially comprises three elements: a wellhead or ex-plant price, a pipeline transportation tariff and an end-user tariff. As discussed above, the first two elements are under the control of the central government through NDRC, and end-user tariffs are set locally.

Figure 64 Traditional pricing regime for domestic gas, China



In general terms, the ex-plant price consists of the wellhead cost (for the given well or basin) inclusive of purification fees and financing costs and taxes, plus a producer margin. Different ex-plant prices (for any given field) are set for the various end users. Transportation tariffs are determined based primarily on the pipeline construction and operation costs plus a margin, and are varied according to the transportation distance from the source to the city gate or customer and, in some cases, also by end use. The summation of these two components constitutes the end-use price for large customers (fertilisers, bulk industry and power producers) and the city gate price. Provincial governments determine end-user tariffs for smaller users after taking into account the distribution cost and also local socioeconomic factors such as affordability and alternative fuel prices.

Despite its complexity, this pricing regime was sustainable while China remained self-sufficient in natural gas. However, with the introduction of natural gas imports and the growing import dependency of the country, the pricing regime has come under challenge. This is due to increasing procurement costs resulting from more expensive imported pipeline gas from Turkmenistan, LNG under new and more expensive contracts (given the higher oil price environment) and also costly LNG spot purchases. There is therefore a growing divergence between the prices of domestically produced and imported gas (domestic prices are currently considered to be about half of import prices) and with imports becoming a larger part of the overall supply mix, the weighted average cost of gas is expected to continue increasing. These challenges are compounded further by the lack of an explicit mechanism for passing through additional costs to end-users.

In response to these pressures, NDRC has piloted pricing reform in two provinces (Guangdong and Guangxi) with the intention that this eventually be rolled out nationwide. Specifically, a 'netback' gas pricing policy has been introduced that links the benchmark gas price, which is set at the Shanghai city gate, to the import price of oil substitutes for gas. The city-gate price for each province is determined by deducting the transmission tariff from the benchmark price. This reform, which was confirmed again in 2012 with the release of the new gas utilisation policy, signals a departure from controls on upstream pricing and a shift to more market-based approaches.

The following sub-sections provide more detail about the current pricing regime and the recently instituted reforms.

Upstream pricing

Ex-plant prices

Domestic ex-plant prices for onshore production are set for each gas field by NDRC with different prices by end-user – fertiliser, industrial, residential and power sectors. The price is determined primarily on the basis of the field production costs, inclusive of taxation and financing costs, plus a gas processing fee and a producer margin, which in many cases entails an internal rate of return (IRR) of 12% although it varies across fields. Customer affordability is also a key determinant of gas price regulation and the residential and fertiliser sectors have been favoured ahead of industry and power generation. The prices 'set' by NDRC essentially represent a reference price and there is a 10% allowance for upward adjustments following negotiations between producers and buyers.

In the case of offshore production, prices are not regulated by NDRC; rather, they are negotiated between CNOOC and its foreign PSC partners. Typically, gas sales agreements are long-term contracts consisting of a base price and adjustment formulae based on a basket of crude oil prices and other factors, together with provisions for periodic revisions.

Ex-plant prices were relatively low until the late 1990s because associated gas was dominant in production but in the 2000s prices have increased significantly and in several phases. In 2010, CNPC earned 3.99 US $/mmbtu, Sinopec earned 4.90 US$/mmbtu and CNOOC 4.96 US$/mmbtu. These wellhead prices represent an 80%-100% increase relative to 2005 levels.

Import prices

Pipeline import contracts (for existing Turkmen gas and impending supplies from Myanmar) are negotiated on a bilateral basis by CNPC and its counterparts. These contracts are oil-linked and generally higher than domestically produced gas. For example, the border price for Turkmen gas stood at 9.1 US$/mmbtu in October 2011 (at 100 US$/barrel). If CNPC were required to sell at prevailing city gate prices determined on the basis of less expensive domestically produced gas (and after taking into account transportation costs), it would incur significant losses. For this reason, the central government has granted a VAT rebate to state-mandated gas imports in cases where import prices exceed domestic wholesale gas prices for the ten-year period 2011-2020.[46]

LNG import prices are oil-linked and determined by bilateral commercial negotiations between importers (primarily CNOOC) and suppliers. Although China's early LNG contracts in 2005/2006 with Australia and Indonesia were negotiated at very low levels (at around 4 US$/mmbtu), contracts signed between 2009 and 2011 have been much higher so that over that time the average LNG import price has almost doubled to 8.5 US$/mmbtu.

Wholesale pricing

For domestically produced gas, the wholesale price is given by the ex-plant price to which the transportation tariff is added. Transportation tariffs are set by the central government (NDRC) on a case-by-case basis and are determined by the pipeline construction and operation costs plus a 12% IRR (or 15% for projects involving foreign investment) with a variation by distance and end user. As a result, the tariff depends on the consuming region and the length and diameter of the pipelines.

In the case of LNG, the resale price is not directly regulated. Importers are required to negotiate the sale of re-gasified LNG at the wholesale level i.e. with distribution companies or directly to large industry and power companies. Nevertheless, the overall contractual terms require NDRC approval prior to importers obtaining the necessary permits for importing LNG and operating the regasification terminals. Moreover, prices for the city gas consumers require the approval of the local pricing bureaux. In some cases, LNG importers have been obliged to sell at the regulated city-gate price but in others are granted more freedom to sell at market rates.

End user tariffs

Large consumers

End-user prices for 'direct supply' customers (large industrial users, power plants and fertiliser producers) are essentially the ex-plant price plus the transportation tariff. As mentioned above, these vary both by user and distance and there is therefore large variation in end-user prices across the country. Within any given region, the gas price for fertiliser producers is significantly lower than that for the other customer categories.

City gas consumers

As described above, city gate prices are determined according to a complex matrix of ex-plant prices for each gas field and consuming sector, and pipeline transportation tariffs for each city (which in turn often differ by user). Based on these city gate prices, the provincial and local pricing bureaux regulate retail prices, again with sectoral variations. The approach is generally cost-plus, with retail prices consisting of the city-gate prices plus local distribution network charges, which in turn comprise cost plus margin. However, in setting final prices, provincial and local governments take into account a number of factors including the type of end user, ability to pay, the competiveness of gas against alternative fuels and the structure of gas demand in the area. Adjustments in city gate prices are normally passed

[46] The current VAT rate for gas is 13%.

through quickly to commercial and industrial end users. Price changes for the residential sector usually have a longer review time as a public hearing is generally required.

As a result of China's pricing regime, there is significant variation in end-user prices across the country. Generally, the coastal and central regions have higher prices for all three end-use sectors (residential, commercial, industry) than the western (gas producing) regions. The disparity in end use prices reflects the varying costs of production and infrastructure supplying the different markets, but also local government priorities and customer affordability.

The new pricing reforms

In December 2011, the NDRC published for the first time a detailed gas pricing mechanism and selected Guangdong and Guangxi as the first two provinces to introduce the pilot pricing regime. At the end of 2012, the NDRC further confirmed and reinforced this new pricing policy stating its intention to "expedite the establishment of a price linkage between the natural gas price and the prices of alternative fuels" and to "establish and improve the price linkage from upstream to downstream".

Under the new policy, the Shanghai city-gate has been chosen as the national price benchmark given its role as a centre for different supply sources and pipeline distribution. A price-setting formula has been set of the following form:

$$P_{gas} = K \times \left(\alpha \times P_{fuel\ oil} \times \frac{H_{gas}}{H_{fuel\ oil}} + \beta \times P_{LPG} \times \frac{H_{gas}}{H_{LPG}}\right) \times (1 + R)$$

Where:

P_{gas} is the natural gas city-gate price in RMB/cubic metre

K is a discount rate, set at 0.9

α and β are the weighted percentage of fuel oil and LPG, 60% and 40% respectively

$P_{fuel\ oil}$ and P_{LPG} are the import prices for the respective products during the period in RMB/kg

$H_{fuel\ oil}$, H_{LPG} and H_{gas} are the heat content of fuel oil, LPG and natural gas set as 10,000Mcal/kg, 12,000 Mcal/kg and 8,000 Mcal/kg, respectively

R is the natural gas VAT rate, currently at 13%.

As is evident from the formula, the National City gate benchmark price has been linked to the alternative fuel prices of fuel oil and LPG, with weights of 60% and 40%, respectively. A 10% discount against the weighted average price is temporarily applied to ensure the competitiveness of gas. The city-gate price for each province is determined by deducting the transmission tariff from this benchmark price, while sellers and buyers can negotiate within the limits of the regulated provincial city-gate prices.

There are a number of uncertainties or concerns associated with this new pricing mechanism, including the appropriateness of the benchmark location and the alternative fuels included in the formula (for example, the major competitor to gas in the electricity and industrial sectors is coal, rather than oil). Also, local governments retain the authority to set end user prices on the basis of local affordability and other social and economic indicators. While NDRC has indicated that local governments can allow cost pass-through of the new prices, it is unclear to what extent and how this will happen in practice.

Despite these concerns, the new pricing regime (if implemented) will replace the existing fragmented cost plus wellhead price and a transportation tariff that varies by gas source and route, with a unified city-gate price for each province. The pricing reform will also expose city gate prices to more (albeit limited) market forces and allow for netback pricing at the wellhead.

E.1.2 Gas allocation mechanism

China's first natural gas utilisation policy was issued by the NDRC in 2007 but has now been replaced by a new policy that became effective in December 2012.

The 2007 policy had classified gas users in China into four categories – "preferred," "permitted," "restricted" and "prohibited". Users within the first two categories could enjoy certain priority treatment in project approvals and gas pricing, as well as preferential assurance of gas supply, while users in the last two categories could encounter restrictions in those aspects. The preferred users under the 2007 policy were urban residential customers, public service facilities, natural gas vehicles, and distributed combined heat and power generation. This reflected the central government's aim of ensuring gas availability for urban communities at a time when gas supply was still relatively limited.

The 2012 policy has increased the types of users included under the "preferred" category to 12 sub-categories, in keeping with the increase in gas supply. Moreover, natural gas-fired power projects have now moved up into the "permitted" category (they were previously restricted or prohibited). Under the new policy, gas-fired power projects are permitted to be built anywhere in China except that the construction of base load gas-fired power projects is still prohibited in 13 large coal-producing areas.

E.1.3 Recovering the costs of gas

Electricity sector

China operates under a single buyer model. Generation is sold to six regional state-owned grid companies under long-term contracts that are set and approved by the central government. In turn, the grid companies sell power to end users under local government-approved retail tariffs.

Chinese electricity dispatch is organised by providing a similar amount of hours per year to each plant regardless of its efficiency or fuel consumption costs. Prices paid to power generators are set on a technology-wide basis in each province. For example, within a given province, all new CCGT plants would be paid the same price, which in turn is different from the price paid to other technologies, such as coal-fired generation or hydropower.[47] Each technology price is based on the current estimated provincial-specific construction and operating costs.

[47] This is similar to standard offer pricing employed in many countries in the case of renewable energy technology.

Automatic adjustments to electricity prices are only permitted for coal-fired generators when the price of coal moves by more than 5% within a period of six months. No such automatic adjustment mechanism appears to apply to other fuels, such as natural gas, although the NDRC may adjust prices periodically to reflect changes in fuel prices. Nevertheless, even in the case of coal, since 2004 electricity prices have been adjusted only three times despite the 5% threshold being exceeded more than 10 times.

Fertiliser sector

The fertiliser industry in China is undergoing significant change as it moves to market based arrangements, but continues to receive preferential treatment as it is considered integral to assuring the country's food security. The sector receives a number of input subsidies, the most important of which are the preferential prices for natural gas (where fertiliser producers receive the lowest tariff among all gas users) and electricity. Consequently, recovering the cost of gas in this sector has not been a significant issue to date. In fact, the low price of gas has created some perverse outcomes in that several producers have exported products from cheap gas, despite government intentions to allocate in favour of domestic farmers and agricultural production.

Other sectors

The other major gas consuming sector is industry (chemicals production and manufacturers requiring clean and efficient industrial processing, such as glass, ceramics and electronics). Although gas prices for industrial use are generally the highest and are used to cross-subsidise the residential and fertiliser sectors, natural gas continues to be competitive against most alternative fuels (e.g. LPG, fuel oil and coal gas), with the exception of coal. For example, the average natural gas tariff for industry in 36 major Chinese cities in 2011 was 13 US$/mmbtu. This implied around a 50% discount to LPG and a 60% discount to diesel at the time. Hence, industry has generally had the capacity to absorb increasing gas prices.

E.1.4 Recovering infrastructure costs

Unbundling of infrastructure

There is no regime for regulated access to pipeline networks or to LNG import facilities in China. Any such access is based on bilateral negotiations and agreement. As no company other than the three NOCs has sourced imports for the Chinese market, it seems even this possibility is practically blocked.

Terminal infrastructure charges

As discussed earlier, LNG importers are required to negotiate the sale of re-gasified LNG (inclusive of terminal charges) with distribution companies or directly to large industry and power companies. Although these prices are not formally regulated, overall contractual terms require NDRC approval prior to importers obtaining the necessary permits for importing LNG and operating LNG terminals, while local pricing bureaux also further scrutinise prices for city gas consumers.

Pipeline infrastructure charges

The basis for setting pipeline charges has been discussed earlier. To repeat, transportation tariffs are set by individual pipeline and are determined by construction and operating costs plus an IRR normally equal to 12% with a variation by distance and end user. In addition, accelerated depreciation periods of approximately 10 years are used, which, given the normal technical lifetime of gas pipelines (40 to 60 years), potentially leads to higher pipeline tariffs than otherwise would be the case.

E.2 Japan Gas Price Approach

E.2.1 Gas pricing

Upstream pricing

The early Japanese LNG import contracts in the 1970s have set the 'benchmark' for pricing of LNG in Asia and the linkage to crude oil. Although there have been variations in the formula over time and across countries in response to changed market circumstances, the pricing formula employed is generally of the following linear form:

$$P_{LNG} = \alpha \times P_{Crude\ Oil} + \beta$$

Where

P_{LNG} is the price of LNG in US$/mmbtu

$P_{Crude\ Oil}$ is the price of crude oil in US$ per barrel

α and β are constants negotiated by the buyer and seller

The constant α is known as the slope and is typically expressed as a percentage, so that if it were equal to 0.15 it would be referred to as a slope of 15%. It can be demonstrated that with a slope of less than approximately 17% and a positive constant β, the resulting LNG price is at a premium to crude oil at low prices, which gradually erodes and then turns into a discount as the price of crude increases.

Subsequent revisions to Japanese LNG import contracts have seen refinements to the above simple formula to account for changing market conditions. The most important of these has been the introduction of the so-called 'S-curve' and the use of the Japan customs cleared crude oil price or the "Japanese Crude Cocktail" (JCC) as the reference oil price. The S-curve means that there are different (lower) gradients at the lower and upper end of the price curve, which are designed to protect sellers and buyers, respectively, against adverse movements in the oil price.

A distinguishing feature of Japanese long-term LNG import contracts in recent years has been the widening disparity of prices. In the early 2000s, Japanese prices moved within a narrow range around an average of about 5 US$/mmbtu, but since the beginning of 2004 the range has widened significantly. At the bottom end of the range are a few contracts finalised during the buyers' market of the early 2000s with slopes below 10% and at the upper end are more recent contracts with slopes above 15%.

Wholesale pricing

Japanese LNG buyers are gas and power companies carrying out business in an integrated manner, from procurement and imports to transmission, distribution, downstream gas and power supply and marketing. As a result, the Japanese gas market is highly fragmented with regional monopolies and limited competition, despite the ostensible opening of the larger end of the market. The consequence of this is that there is no national gas market and wholesale trading of gas. The few gas trading companies in the country only trade in LNG cargoes, rather than actual pipeline gas deliveries. Nevertheless, in late 2012 the Japanese government announced that it intends creating an LNG futures market that would set prices based on gas supply and demand factors. METI is currently in consultation with power and gas utilities and other stakeholders (traders and financial institutions) on the mechanics of market operation with the intent that listing on a commodity exchange commence from April 2014.

End user tariffs

Japanese end user prices are regulated by METI on a cost plus basis. Japan has historically had higher gas prices for both residential and industrial customers than in other OECD countries. This is partly due to its complete reliance on imported LNG supply, but also (in the case of residential consumers) relatively low consumption per household compared to Europe and the US.

E.2.2 Gas allocation mechanism

There is no formal gas allocation mechanism in Japan. Individual gas and power utilities are responsible for sourcing gas for their own use or their consumer base.

E.2.3 Recovering the costs of gas

Electricity sector

Some Japanese electricity utilities adopt a fuel cost adjustment mechanism to set electricity tariffs. Under this system, an adjustment is made to electricity prices every month based on the average prices of crude, LNG and imported coal. The LNG price used for this purpose is the average price of all the LNG imported into Japan each month i.e. it represents average LNG procurement costs, irrespective of an individual buyer's actual purchase costs.

Other sectors

A similar system to that employed in electricity is also in place for downstream gas prices. That is, a cost adjustment system is in place that passes through average LNG procurement costs to end users, taking into account external factors such as crude oil price and exchange rate changes. Price changes for large customers normally occur with a one-month lag and with a lag of two months for smaller customers.

E.2.4 Recovering infrastructure costs

Unbundling of infrastructure

As previously discussed, a TPA regime was instituted in 2004. This requires that gas utilities and 'pipeline service providers' offer negotiated access to third parties and they cannot refuse such access unless there is justifiable reason, such as technical capacity constraints. Moreover, gas utilities are required to keep separate accounts for transportation services and other relevant services and to publicise the relevant accounting data. This 'functional unbundling' was introduced to ensure fair and transparent accounting provisions and to encourage new entry. The bundling provisions, however, are not rigorously enforced in the manner that they are, for example, in Europe or the US.

In the case of LNG infrastructure, there is no mandatory functional unbundling. However, gas trading guidelines stipulate that it is 'desirable' that business operators that own or manage LNG terminals create manuals for negotiations about the use of LNG terminals by third-party companies so as to clarify the preconditions and rules for such negotiations from the viewpoint of ensuring fair and effective competition. Moreover, the guidelines also state that is desirable that such business operators ensure sufficient information disclosure regarding the capacity of LNG terminals, the current status of capacity utilisation and plans for future utilisation so as to enable an estimate of spare capacity.

Some LNG terminal operators have developed access guidelines, but in practice it has generally proven difficult to establish TPA at LNG terminals. This is because LNG regasification terminals are generally designed to match an importer's specific supply portfolio (secured under long term contract) within the terminal's hinterland. The lack of network interconnection between regions described earlier further constrains the ability and the incentive to secure TPA and increase competition.

Terminal infrastructure charges

The LNG terminals in Japan have either been developed as merchant operations acting as both importer and marketer or for own gas use by power utilities. Under both types of arrangement, the LNG owners and operators effectively pay for their own services through the margin achieved between the cost of gas and the sales price (either as gas or electricity) into their local market. In the absence of a transparent TPA regime, it is not clear what terminal infrastructure charges apply in Japan.

Pipeline infrastructure charges

There is limited information on pipeline infrastructure charges in Japan given that access is on a negotiated basis and limited in practice.

E.3 Malaysia Gas Price Framework

E.3.1 Gas pricing

Upstream pricing

Malaysia carries out its exploration, development and production activities through its National Oil Company, Petronas, through Production Sharing Contracts (PSC) with a number of international oil and gas companies and with its wholly owned subsidiary, Petronas Carigali Sdn Bhd. While there is no specific mechanism for pricing gas at the wellhead or LNG at the re-gasification terminals, the comparatively low price of domestic gas - compared to high gas export prices - has acted as a disincentive for gas producers to supply gas domestically[48].

As a result the Government chose to implement a new policy to attract foreign investment which led to the introduction of a novel PSC concept in 1997. This allowed gas producers to have significantly larger fiscal benefits to attract them to Malaysian gas markets. The new PSC is based on the "revenue over cost" concept (R/C PSC) which allows PSC Contractors to accelerate their cost recovery if the contractors achieved certain cost targets[49]. The basic principle of R/C PSC is to allow the PSC Contractors a higher share of production when the Contractor's profitability is low and to increase Petronas share of production when Contractor's profitability improves. The contractor's profitability is measured by the "R/C Index," which is the ratio of the contractor's cumulative revenue over the contractor's cumulative costs.

Despite these measures the price of gas in Malaysia continues to be significantly below the world market – a direct consequence of the governmental subsidies – and thus has led to a large share of gas production being exported.

As Petronas is the sole domestic gas wholesaler and is also involved in all gas production, domestic buying contracts are determined during initial development of the field. Government allocations of gas to offshore Sabah and Sarawak also have to be met after which subsequent gas is allocated for offshore peninsular Malaysia and LNG exports.

Wholesale pricing

Malaysia is suffering from a low domestic gas price which is attracting producers to sell their gas in other higher price zones. The reason for this low domestic price is due to the significant government subsidies in place to protect the domestic consumers from high or volatile prices. Table 11 displays the disparity between unsubsidized and subsidized prices to large natural gas consumers in 2011.

[48] (The Economist Intelligence Unit, February 2013)
[49] (Putrohari, Kasyanto, Suryanto, & Abdul Rashid, 2007)

Table 11 Malaysia Wholesale Gas Pricing

Natural Gas Consumer	Subsidized Price per mmbtu	Unsubsidized Price per mmbtu
Electric Power Sector	RM10.70 (US$3.21)	RM41.16 (US$12.35)
Large Power Consumers	RM15.35 (US$4.54)	RM56.20 (US$16.86)
Gas Malaysia	RM11.05 (US$3.32)	RM42.35 (US$12.71)
LNG Exports	-	RM56.00 (US$16.80)

Source: Zuraimi Abdullah. "Hidden cost to Subsidies." New Straits Times April 12 2010. High Beam Research (September 18, 2011). http://www.highbeam.com/doc/1P1-178619780.html

In addition to this the Department of Agriculture noted that the price for natural gas to consumers in the fertilizer industry was less than US$1 per mmbtu. The government has decided to reduce the subsidy value in the coming years and has estimated that the country would embrace the global market rate for gas by 2015[50]. This would lead to a reduction in the effects of demand destruction that low domestic gas prices are having in the gas industry. This is understandable considering the price for LNG exports to Asia-Pacific was RM56 (US$16.80)/mmbtu[51].

End user tariffs

Gas Malaysia transports gas to final end users which are distributed into three major categories: industrial users, commercial users and residential users. Gas prices charged by Gas Malaysia are regulated by the Economic Planning Unit. Users are divided into seven key categories (based on usage requirements) and are charged accordingly. Table 12 below portrays the tariff charged to the different bands of consumers.

Table 12 Malaysia End User Gas Pricing

Tariff Category	Applicable Range mmbtu/month (mmbtu/year)	Tariff (RM/mmbtu)
A		19.52
B	0 - 50 (0 - 600)	20.61
C	51 - 416 (601 - 5,000)	13.98
D	417 - 4,166 (5,001 - 50,000)	14.61

50 (Maybank, 2012)
51 (Maybank, 2012)

Tariff Category	Applicable Range mmbtu/month (mmbtu/year)	Tariff (RM/mmbtu)
E	4,167 - 16,666 (50,001 - 200,000)	16.07
F	16,667 - 62,500 (200,001 - 750,000)	16.07
L	> 62,500 (> 750,000)	16.45
AVERAGE		16.07

Source: Gas Malaysia

E.3.2 Gas allocation mechanism

The Malaysian government has imposed a Utilization Objective that serves as its gas allocation mechanism. This Objective relies heavily on the energy industry and consumers to exercise efficiency in energy production, transportation, conversion, utilization and consumption through the implementation of awareness programmes[52]. Demand side management initiatives by the utilities, particularly through tariff incentives, have had some impact on efficient utilization and consumption. The government has also launched initiatives to encourage co-generation to promote an efficient method for generating heat and electric energy from a single source.

The Government realizes that to enhance the success of its Utilization Objective, the market approach needs to be supplemented by the regulatory approach. Hence, the government is currently formulating a new Energy Efficiency Regulation which will be focusing on designation of large consumers, appointment of energy managers and equipment labelling.

In addition, the Government is continuing its work alongside industry to promote energy efficiency to reduce inefficient and wasteful use of energy in industrial facilities. A number of industrial energy efficiency initiatives are being planned and these include energy auditing programs, energy service companies support programmes and technology demonstration programmes[53].

E.3.3 Recovering the costs of gas

Electricity sector

Changes in gas price are accounted for by primarily transmitting the changes in cost downstream to the final end customer. With Malaysia being heavily dependent upon gas as its primary source of electricity, this does make electricity tariffs vary with changes in gas prices.

Historically due to the large subsidies placed by the governments on the prices of gas, prices have not been extremely volatile thus not leading to large gas driven variations in electricity

[52] (Ministry of Energy, Green Technology and Water, 2009)
[53] (Ministry of Energy, Green Technology and Water, 2009)

tariffs. However, as the government seeks to reduce the subsidies on the gas sector, the rising gas prices has led to significant changes in the electricity sector.
In 2011 a 28% upward revision of gas prices to the power sector (from RM10.70 (US$3.21)/mmbtu to RM 13.70 (US$4.11)/mmbtu) led to an average increase of 5.12% in electricity tariffs. While domestic customers (using below 300kWh per month) were protected from this increase, industrial and commercial customers received average increases of 8.35% in their tariffs[54].

Fertiliser sector

Natural gas subsidies in the fertiliser sector have once again led to very few changes in gas prices. As a result, the fertiliser sector has not had to face the issues of how to deal with increasing or decreasing gas prices. The industry will have to come to terms with these issues in the near future as gas prices begin to rise as the government reduces its subsidies.

Other sectors

The other key sectors that use domestic gas are the basic metal industries and non-metallic industries. Both of these industries use less than 20% of total Malaysian industrial consumption. As a result, they are not key drivers in the gas industry.

E.3.4 Recovering infrastructure costs

Unbundling of infrastructure

While originally, the gas transmission pipeline network was solely used by Petronas Gas, after the passing of the Third Party Access (TPA) initiative, the transmission pipelines are open for access by interested parties who wish to participate in Peninsular Malaysia's gas market.
While there are stringent rules and network codes for use of these pipelines, the benefits from this initiative include the improved security of gas supply in Malaysia, additional opportunities for industries and businesses to source their own gas supply and provision of growth opportunities for energy players. All third parties seeking to participate in this scheme must enter into a legally binding Gas Transportation Agreement or Grid Connection Agreement with the transporter.[55]

Terminal infrastructure charges

The Petronas Gas code clearly states that "services of Transporter shall not include the production, processing or sale of gas." Thus there exist no rights of access to processing facilities.

Pipeline infrastructure charges

Transportation tariffs for third parties using the national pipeline grid are laid out in a zonal system. The Gas transportation system is divided into 4 zones and specific tariffs are applied depending on where the gas was being transported from and the final destination.

[54] (Tenaga Nasional Berhad)
[55] (Petronas Gas, 2011)

There are two types of transportation charges available: Firm transportation charges and interruptible transport charges. Firm transportation charges incur a higher tariff and allow the shipper to reserve the right to flow gas through gas transportation system in a transportation path from entry point to exit point. Interruptible transportation charges are lower by a fixed factor and entitle the shipper to receive interruptible capacity – which is nominated on a daily basis. Tariffs are adjusted on 1 April 2014 and every 5 years after this date.

Unused capacity may be offered to any other shipper as available interruptible capacity which allows more freedom for the third parties involved.

E.4 Thailand Gas Price Framework

E.4.1 Gas pricing

Upstream pricing

The wellhead gas price is specified in the gas purchase contract signed between the producer and PTT. It is normally indexed with the price of fuel oil, the exchange rate, and the consumer and producer price index. The price for natural gas produced from the Gulf of Thailand is roughly US$2/mmbtu. Gas procured from joint development with neighbouring Malaysia and Myanmar is slightly more expensive at US$2.3-2.75/mmbtu. Significantly lower wellhead gas prices are common for less mature gas fields.[56]

Wholesale pricing

The wholesale gas price in Thailand comprises the wellhead price, a marketing margin, the transmission tariff and the distribution tariff. After determining the wellhead price – as noted in the section above – the marketing margin is regulated by the Electricity Policy and Planning Office (EPPO) in the Ministry of Energy. The current rate of the pooled gas price (the weighted average price of gas purchased from various production sources) is 1.75% for sales to IPPs and EGAT and 9.33% for SPPs. The higher margin reflects the higher risks that PTT has to bear as SPP contracts are shorter (5 years as opposed to 20-25 years) and allow an SPP to switch from one source of energy to another depending on the price level. However, this rate is currently being revised downward as statistics show that SPPs rarely exercise this option. Hence the risk involved with the contract may have been overestimated. However, since 1999 a cap of THB2.15 [US$0.07] (which equates to a rate of less than 1%) has been imposed.

The transmission tariff is set by EPPO with approval from the Minister of Energy. The tariff is uniform for all gas customers and is made up of the demand charge (TD) component to cover fixed costs and the commodity charge (TC) to cover variable costs. The rate of return on capital used for the demand charge is 18% for older pipelines and 12% for new pipelines (pipelines installed after 2007). The value used in the price cap has always been 2%. The cap is revised every 5 years or when a new investment qualifies for a revision of the capital allowance. Finally, the distribution tariff is unregulated and PTT typically negotiates a price for this tariff directly with its customers.

[56] (Nikomborirak)

End user tariffs

Electricity tariffs and pass-through of gas price are discussed earlier.

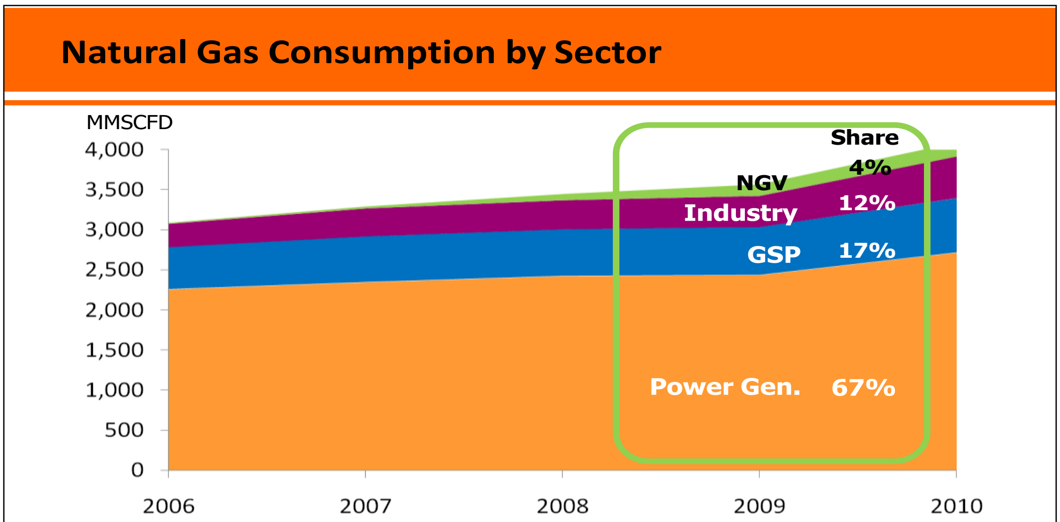
E.4.2 Gas allocation mechanism

The vast majority of gas utilization occurs in the power sector. EPPO reported that in 2010 67% of domestic gas consumption occurred in the power sector. An additional 17% was utilized in gas separation plants operated by PTT. The remaining 16% was used in other industries and as NGV.

While there is not any official policy pertaining to gas utilization and allocation, the Ministry of Energy has indicated its desire to set the alternative energy usage as national agenda by "encouraging the production and usage of alternative energy, especially bio-fuel and bio-mass." In addition, there has also been mention to try and reduce the dependence of gas driven electricity generation to help ease the transition to a less regulated industry.

Figure 65 below displays the current utilization of gas in Thailand's domestic sectors.

Figure 65 Thailand's Natural Gas Supply, 1990-2011



Growth Rate (%)	Power Generation	Gas Separation Plant	Industry	NGV	TOTAL*
2008	3.3	1.9	4.0	220.8	5.0
2009	0.2	2.5	6.9	84.2	3.2
2010*	11.6	13.0	33.7	22.6	14.7

* Preliminary data

Source: EPPO Energy Forecast 2010

E.4.3 Recovering the costs of gas

Electricity sector

Electricity tariffs and pass-through of gas price are discussed later.

Other sectors

Other than the power sector, gas is primarily used for petrochemicals. There is limited industrial demand and a small but rapidly growing NGV market.

Gas is priced at the prevailing pool price plus margin for these sectors. However, the retail price of NGV is set below the cost-recovery level, with the difference being compensated by a subsidy from the government budget to PTT, in order to promote its use over petroleum products[57]. By end-2012, the accumulated losses to PTT under this mechanism to be covered by subsidies were reported at almost US$ 2 billion and increasing by around US$ 600 million annually.

Concerns over the level of this subsidy led government to move in 2012 to increase the selling price for NGV from Bt 8.50 /kg (~US$ 0.3 /kg) to the then-estimated cost-recovery level of Bt 12 /kg (~US$ 0.4 /kg) in a series of staged increases. There was very strong opposition to this and the government subsequently ended the series of price increases at a level of Bt 10.50 / kg[58].

E.4.4 Recovering infrastructure costs

Unbundling of infrastructure

There are no legal restrictions on new entries into any of the natural gas business subsectors including the importation of LNG. However, PTT's monopoly in transmission - and hence buying and selling of gas - amounts to significant barriers to entry.

Additionally, PTT prefers to enter into longer term contracts with entities such as EGAT or other IPPs which will ensure that its large capital costs will be recovered. PTT does offer shorter term contracts to other small independent power producers (SPPs) but these are offered at significantly higher mark ups to reduce the risk incurred by PTT.

Terminal infrastructure charges

As part of Thailand's efforts to secure more gas supply and supplement the country's pipeline imports from Burma, the country commenced operations of its first re-gasification terminal at Ma Ta Phut economic zone in the Rayong area in 2011. While there are no legal restrictions on new entries into the natural gas business subsectors including the importation of LNG, due to PTT's *de facto* monopoly on gas transmission lines, all imports would have to be transported using PTT's approval.

Pipeline infrastructure charges

Thailand's natural gas transmission infrastructure is very advanced compared to other ASEAN countries. PTT Natural Gas Distribution (PTTNGD) currently has 2,434 miles of total natural gas transmission and distribution pipelines throughout the country. The 1,972-mile offshore transmission system links fields in the Gulf of Thailand to the country's six gas separation plants supplying gas by-products to petrochemical facilities and other markets. The 764-mile onshore portion consists of both eastern and western sections linking the gas

[57] Thailand's energy policy emphasizes the replacement of oil imports with natural gas, biofuels and renewable energy.
[58] The current NGV retail price is equivalent to approximately US$ 0.23 / litre of gasoline. The current retail price for gasoline (gasohol 91 E10) is approximately US$ 1.20 / litre.

separation plants and gas from Burma to power facilities. While such a network would be extremely useful for transporting of gas, PTT has monopolistic rights over gas transmission in Thailand. Hence, there is no scope of third party access for pipelines within the country.

Appendix F Case Study: Western Australia Gas Market Development

F.1 Background

The natural gas industry in Western Australia has grown over 50 years from the discovery of gas in the onshore Perth Basin, approximately 350km north of the state capital, Perth, to become a key input into the domestic economy and one of Australia's leading commodity export industries. This development has been achieved through a combination of regulatory and market mechanisms introduced over time, with each step tested and refined before moving ahead to the next one. It is a useful model from which to apply lessons learned to the development of a gas market in Viet Nam.

Until the early 1970's, Western Australia was reliant on indigenous coal and imported oil for its energy supply. The state's economy was based on agriculture and mining, with services industries focussed on supporting these primary industries. However, opportunities for economic expansion had been identified, particularly in minerals processing, but a secure energy supply was essential for the state to achieve its potential.

Natural gas was first discovered in the Mondarra and Dongara fields in the onshore Perth Basin by West Australian Petroleum Pty Ltd ("WAPET") – a joint venture between Caltex and Ampol – in 1965 and over the following 2 years was proven up to demonstrate its commercial viability. In 1971, WAPET commenced construction of the Parmelia Gas Pipeline to connect its gas fields to Perth and the adjacent industrial areas. The foundation customer was the State Energy Commission of Western Australia ("SECWA" – the government owned electricity and gas utility. SECWA installed multi-fuel (coal/gas/oil) fired boilers at its Kwinana Power Station and retailed gas to industrial customers, including Alcoa of Australia which converted the calcining process at its Kwinana and Pinjarra alumina refineries from oil to gas.

However, gas supply from the Perth Basin was limited to around 120TJ/day (114bbtu/day) by reserves, processing capacity and pipeline capacity. During the 1970's, the Government of Western Australia continued to encourage exploration for oil and gas, particularly in the highly prospective off-shore Carnarvon Basin 1,500km north of Perth, where the North West Shelf Gas fields were discovered in 1975.

F.2 Early Market Developments

In 1979, the Western Australian Government, through SECWA, reached agreement with the North West Shelf Gas Joint Venture ("NWSG", comprising Woodside, BHP Petroleum, BP, Chevron and Shell) and foundation customers, Alcoa of Australia and Japanese LNG buyers, to develop the North West Shelf Gas project. The first phase of the NSWG project was the construction of a domestic gas processing plant and the 1,600km long Dampier to Bunbury Natural Gas Pipeline ("DBNGP") which were commissioned in 1984. The LNG plant was commissioned in 1987.

From 1984 until 1994, SECWA was the single buyer of gas from NWSG. It used gas for power generation and sold gas to retail and industrial customers in Perth and the surrounding industrial areas, as well as to some mining operations in the Pilbara region near the gas production facilities.

With an initial capacity of 350TJ/day (340bbtu/day), the DBNGP was a catalyst for the development of new industries and expansion of existing industries, including nickel processing, alumina refining, LPG refining, fertilisers and petrochemicals as well as expanding the market for retail gas to households, commercial businesses and small industries. SECWA remained a vertically energy business operating in every part of the gas supply chain, except exploration and production, including as the largest customer through its power stations.

By 1994, Apache-operated joint ventures had established gas processing facilities on Varanus Is, just to the south of the NWSG facilities and the customer base for gas had diversified from power generation and alumina refining. In recognition of the changes in the market, and microeconomic reforms being developed in the energy industry nationally, the Western Australian Government took the first steps towards an open market for gas.

The end customer base had now diversified with the retail gas segment growing to approximately 15% of the market, with power generation accounting for 35% and alumina refining 50%.

F.3 Industry Re-organisation

The first step, in 1994, was to re-organise SECWA into 3 separate government owned businesses.

The electricity generation, transmission, distribution and retail functions were transferred to the Electricity Corporation, known as Western Power. Each of these functions was set up and managed within the Western Power organisation as a separate business unit, accountable for its performance against annual targets, with the central administration and technical services functions established as a service provider to these 4 business units.

The gas transmission, distribution and retail functions were transferred to the Gas Corporation, which traded as Alinta Gas. The same approach to managing the business units was applied by Alinta Gas. In this structure, the retail business unit was required to negotiate terms and conditions for access to the transmission pipelines and distribution networks with the respective business units.

The policy and safety and technical regulatory functions of SECWA were transferred to the Office of Energy which reported directly to the Minister for Energy.

F.4 Contractual Re-organisation

The re-organisation of SECWA required legally enforceable contracts to be established between the various business units of Alinta Gas and between Alinta Gas and Western Power. The broader microeconomic reforms taking place drove further disaggregation of contracts so that SECWA's former industrial customers would have the option to either continue to receive gas from Alinta Gas, or to contract directly with gas producers for gas supply and with Alinta Gas for transport of that gas from the producer to their facility.

To provide a framework for these new contracts, the Western Australian Government introduced the Gas Transmission Regulations and the Gas Distribution Regulations, administered by the Office of Energy to provide the "rules" for parties operating in this new market. The Regulations included template contracts, which were widely adopted by market participants, and tariffs.

The contracts adopted in 1994 allowed for a range of measures designed to encourage the development of a gas market over time. Some of the key features of these contracts are:

- Rights of gas buyers to on-sell gas;
- Rights of buyers to bank gas (i.e. to store take-or-pay gas in the reservoir until it is needed for their operations, or until the end of the contract);
- Access to short term or spot gas supplies and pipeline transportation capacity on pre-agreed terms;
- Rights to store gas in pipelines, or borrow gas from pipeline inventory for short periods to manage imbalances between deliveries into and receipts from the pipeline system;
- Rights of buyers to trade gas between themselves in the pipeline; and
- Rights to relocated pipeline capacity between outlet points to facilitate gas trades and sales between buyers.

These contractual provisions resulted in a basic secondary market being established. This market was administered by the pipeline operators as they had access to all of the necessary data.

In recognition of their foundation customer status, Alcoa of Australia and the LNG export sector were exempt from the Regulations, except in regard to matters of safety. The contracts they had negotiated with the Government of Western Australia to support the development of the NWSG project and the DBNGP were amended only to the extent necessary to allow the industry re-organisation to function efficiently and to allow Alcoa of Australia to access the secondary market.

The market now looked quite different from both an ownership and customer base perspective. Approximately 55% of gas consumed in Western Australia was now being purchased by private sector business with the former SECWA businesses now accounting for 45% of gas sales. However, as the market had grown from 300TJ/day in 1985 to 420TJ/day in 1995, the actual consumption and sales of Western Power and Alinta Gas were approximately 25% higher after disaggregation than they had been 10 years earlier.

The customer base had now diversified so that alumina was now approximately 48% of the market, power generation 29%, industry 7% and retail gas 16%.

F.5 Second Phase Industry Re-organisation

The period from 1994 to 2005 was largely one of consolidation of the arrangements which had been put in place in 1994, with some refinement of the industry structures. It was also a period where the gas industry grew on the back of the reforms which had been put in place with new suppliers, new pipelines and new customers entering the market.

The Western Australian Government continued with its institutional re-organisation to ensure that industry structures could continue to support the growing market.

In 1997, the transmission pipeline division of Alinta Gas was separated from the rest of the business and sold to a private sector operator, Epic Energy. Epic Energy was responsible for the operations and development of the DBNGP, but the Government maintained control of technical and safety standards and tariffs through the Gas Transmission Regulations.

In 1999, the Office of Energy was re-organised into 3 separate regulatory bodies, each with a very specific focus:

- The Economic Regulation Authority (“ERA”) was given responsibility for overseeing the tariffs and terms and conditions for access to pipelines being sought by the operators. It also had responsibility for terms and conditions and charges for electricity, water and rail infrastructure. The ERA reports to the parliament;
- Technical and safety regulation of high pressure pipelines and all upstream facilities was transferred to a division of the Department of Mines and Petroleum; and
- Technical and safety regulation of distribution networks and consumer installations and responsibility for emergency management was transferred to a division of the Department of Consumer Protection, which retained the Office of Energy name.

The rest of Alinta Gas was listed on the Australian Stock Exchange and sold to the public through a share offer in 2000.

F.6 Second Phase Regulatory Development

In 1998, Western Australia adopted the National Third Party Access Code for Natural Gas Pipeline Systems. This Code had been developed by a joint industry / government working group to set out the rules for access to pipelines and govern tariff and minimum terms and conditions for the services offered by pipelines and the processes to be followed by customers requesting access to those services. The Code is administered in Western Australia by the ERA. It continues to be developed as the industry evolves.

F.7 Second Phase Market Development

In 1996, the 1,400km Goldfields Gas Pipeline (“GGP”) was commissioned with a capacity of approximately 150TJ/day. The GGP initially delivered gas from the processing facilities on Varanus Is to customers (primarily mining operations) in the Western Pilbara and Goldfields regions. This pipeline opened up a new region for gas sales and led to the conversion of many mining operations from diesel power generation to gas fired generation.

During this period both the South West region market serviced by the DBNGP and the Goldfields region market serviced by the GGP continued to grow, with total gas consumed in Western Australia (excluding LNG exports) growing from 420TJ/day to 550TJ/day. This market growth required capacity expansions on both the DBNGP and GGP, and saw an additional producer, a joint venture of Apache and Santos, construct a new processing facility onshore in the Carnarvon Basin.

When it sold Alinta Gas, the Western Australian Government announced that it would open up the retail gas market to competition, allowing other gas sellers to compete with Alinta Gas. It established a joint government / industry working group to develop the rules for the proposed gas market and in 2004 issued the Retail Gas Market Rules to govern the operation of the retail market.

By 2005, the private sector accounted for approximately 70% of the Western Australian gas market, with Western Power's generation plants being the only government-owned facilities.

The growth in demand came primarily from expansions to alumina refining capacity by both Alcoa of Australia and Worsley Alumina, new gas-fired IPP's, industrial loads either converting from diesel or coal to gas and new industrial customers, particularly in the Goldfields region.

F.8 Third Phase Regulatory Developments

While the regulatory frameworks had been supporting market growth, an incident at the Varanus Is gas processing facility resulting in 30% of Western Australia's gas supplies being unavailable for 4 months demonstrated that further refinement was needed in the emergency management aspect of the regulatory framework. The incident was well managed due to the goodwill of the market participants, but the formal systems for emergency management were found to be lacking, especially in regard to transparency of information.

The Office of Energy took the learnings from the Varanus Is incident and used them to further develop the various regulations which govern the operation of the gas market. The key outcomes were the establishment of the Independent Market Operator ("IMO") to oversee all market operations, including having access to operational information, and the issue of a formal Gas Emergency Management Plan by the Minister for Energy.

In 2103, the IMO launched a Gas Bulletin Board on which operational information is published in real time on its web page, allowing both emergency services (in the case of an emergency) and market participants to access flows and capacities. This information is useful to market participants to identify opportunities and assess the state of the market.

F.9 Third Phase Market Developments

Since 2005, the market has continued to grow to almost 1,000TJ/day with customers seeking greater flexibility in how they contract for and take their gas. With a stable functioning regulatory framework in place, developments have focussed on improving the operation of the market to support a range of flexible services being offered to customers.

Gas suppliers and pipeline operators continue to develop new contractual terms to allow customers to store gas on terms which can be tailored to each customer's specific needs and to better meet intra-day demand fluctuations. The Mondarra Gas Storage Facility which uses the depleted Mondarra Gas Field as a storage reservoir and is operated by APA Group which now owns the Parmelia Gas Pipeline, entered commercial operation in 2005 and provides storage and load management services to customers in the South West region.

The first independent gas aggregator, gasTrading Australia ("gTA"), started operations in 2007. gTA manages gas supply and transport contracts for its customers and offers gas which its customers are committed to buy but cannot use on a day for sale through a bulletin board on which buyers offer prices to purchase spot gas which the sellers can accept or reject. After nearly 10 years of operation, gTA now trades around 300TJ per month on behalf of its customers.

In 2013, Kleenheat Gas, which had been supplying LPG in cylinders to industry and small customers for many years, entered the retail gas market in competition with Alinta Gas. Kleenheat's entry into the market has led to lower prices, more flexible services and an expansion of the total market.

AGL Energy announced in 2017 that it also intends to enter the Western Australian retail gas market.

F.10 Introducing Broad Specification Gas

Gas specifications in Western Australia were set with regard to the composition of gas being produced from the various gas fields, the processing costs for that gas with public safety setting absolute limits for some measures, particularly Wobbe Index (which is related to Higher Heating Value). These specifications were initially prescribed in contracts, with the contractual being adopted in Regulations in 1995.

As existing gas reserves were depleting in the mid-2000's, some new discoveries could not be processed commercially to meet historical specifications, even though the composition did not present a risk to public safety.

Following extensive industry consultation, the Western Australian Government passed the *Gas Supply (Gas Quality Specifications) Act* in 2010. This Act provides a mechanism for gas which does not comply with the historical contractual specifications for the various pipeline systems to be developed and delivered to the market, provided that the specification meets the requirements of Australian Standard 4564 Specification for General Purpose Natural Gas.

The practical outcome of this legislative change is to allow gas with a lower than normal heating value or Wobbe Index to be introduced into a pipeline system where it is blended with other gasses. The blended gas stream is supplied to customers, mitigating the effect of the lower specification gas on any particular customer.

The supplier has a choice between installing processing plant to meet historical specifications or paying compensation to any downstream party whose operations are commercially impacted by the lower heating value. As the test for compensation is actual loss suffered by the downstream user, the compensation payable has been negligible to date, due to the mitigation afforded by the blended gas stream.

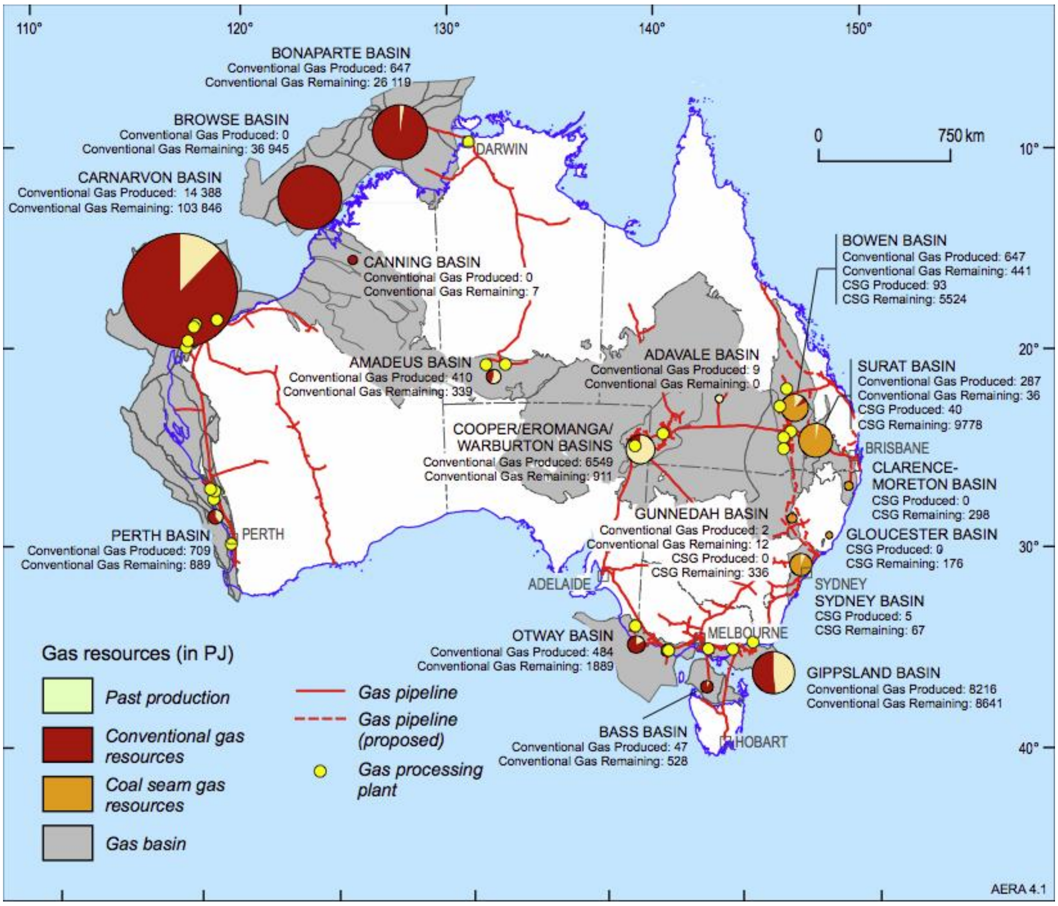
This legislative development has opened the Western Australian gas market to gas resources which can been considered non-commercial, but are now competing with existing gas reserves.

F.11 Conclusion

The development of the Western Australian gas market has been a process of evolution over 20 years and has moved gradually from a government dominated market to one where commercial arrangements operate with regulatory oversight.

The experiences from 20 years of gas industry reform in Western Australia are largely applicable in Viet Nam. The transition from a government owned monopoly to stand alone commercial businesses in each market segment; the establishment of independent policy advisor, technical regulator and economic regulator using resources from the monopoly organisation; the creation of a market and the introduction of broader specification gas to deepen the market are all issues with which Viet Nam must deal in the transition to a liberalised gas market. The experience in Western Australia can inform the process in Viet Nam and provide opportunities to accelerate some reforms from lessons learned.

Figure 66 Australian Gas Industry Map



Source: http://www.ga.gov.au.

Appendix G Case Study: Viet Nam Electricity Reforms Roadmap and its Implementation

G.1 Background to Electricity Industry Reforms Roadmap

Initial restructuring of the Viet Nam power sector began as early as 1995, with the creation of the utility Electricity of Viet Nam (EVN) as part of a broader economic reform program that began in 1986. Consequently, independent power producers (IPPs) were allowed to enter the generation sector in 2000. Nevertheless, the more explicit power sector reform was considered to have started in 2005, when the first Electricity Law came into effect[59]. The objective of the law is to create a competitive, transparent, more efficient, and equitable power market. As one of the implementing tools to achieve this objective, the Government of Viet Nam has formulated the roadmap for electricity market reforms Roadmap, which was promulgated in 2006.

G.1.1 Earlier reforms

Before 1995, Viet Nam's government-owned power sector was managed by the then Ministry of Energy through the three separated regional power companies, each responsible for generation, transmission, and distribution within its own territory. The first stage of reform began in 1995 when these three utilities were merged into a single monopoly power corporation, the EVN, which was commercialised to focus on production and operations. Regulation was still managed by the Ministry of Energy, being merged into the Ministry of Industry. Notably, the beginning of EVN corporatisation was facilitated by the construction and operation of the first 500-kV transmission backbone line joining the three regional transmission networks into an interconnected power system, and the commencement of national load dispatching (power system operations).

Despite having achieved some rapid growth rates of asset and network coverage expansions (particularly in rural electrification), EVN was suffering from financial and managerial difficulties. The major factor was the low electricity tariff rates, which were not commensurate with cost. In 2000, the estimated average tariff to household consumers was US cents 5.87/kWh, which was half a cent lower than in neighbouring Thailand and was the second lowest among five selected Association of South East Asian Nation (ASEAN) countries. The EVN's overall revenues were insufficient for system operational maintenance and investment needs, putting a strain on the state finances. The Government had to compensate EVN's losses through a variety of indirect subsidies such as preferential access to financial resources and special tax treatment.

In 2000, the government started to look beyond the EVN to provide continued and adequate electricity services. IPPs started entering the generation in 2000 with 452 MW, or approximately 7% of total generating capacity, and 2.51 TWh, or 9.2% of total generation. This more than doubled to 15% of the total generating capacity (1,575 MW) and total generation (6.88 TWh) in 2004. In 2003, the government began partly restructuring the EVN, selecting several generation and distribution assets for partial privatisation, referred to as

[59] Asian Development Bank, "Assessment of power sector reforms in Viet Nam: Country report", 2015.

“equitisation.” In 2004, the EVN proposed an equitisation strategy for generation wherein it would retain 100% ownership and control of the three large multipurpose hydropower projects (about 30% of the country’s installed capacity), but the EVN’s remaining eight power plants (about 48% of total installed capacity) would be equitised.

The country’s even more rapidly growing economy push greater pressure on the electricity supply in meeting increased demand. As the economy developed and modernised, it became evident that the single-monopoly public sector model was no longer adequate. An emerging need was to create institutions that were financially viable and adaptable enough to improve system efficiency. Against the limited outcome of initial restructuring and the greater challenges to the sector, a more comprehensive reform program was subsequently introduced with the promulgation of the first Electricity Law.

G.1.2 Promulgation of the first Electricity Law

Viet Nam’s Electricity Law (No. 28-2004-QH11) was approved by the National Assembly in December 2004 and came into effect from July 2005; it governs all aspects of Viet Nam’s electricity industry, including planning, investment, generation, transmission, distribution and the development of wholesale and retail electricity markets. The Electricity Law committed Viet Nam to the introduction of a competitive electricity market. It also formally establishes the sector’s regulatory agency under the MOIT.

The following summarise the law’s relevant contents that specifically stipulate electricity market reforms.

- **Investment in the power sector:** Diversification in power sector investments, allowing participation of all economic sectors with the creation of conditions for reasonable returns of investment and efficient use of energy resources.
- **Electricity pricing:** Sale prices of electricity are implemented in according to the market mechanism with the regulation by the State in conformity with the level of electricity market development. Electricity prices shall encourage energy savings and efficiency.
- **Electricity market development:** The electricity market should be created and operating to ensure openness, transparency, fairness, healthy competition, non-discrimination among market participants. It instructs that the market be established and developed gradually through the three stages of competitive generation, wholesale competition, and retail competition markets.

  The state shall regulate the operation of the electricity markets in order to ensure the sustainable development of the power system, meeting the requirements of safe, stable and efficient supply of electricity.

  The law has also set out the Prime Minister’s responsibility in specifying the conditions, sector structure for each stage of the electricity market; designing the roadmap of electricity market development, reviewing and adjusting the roadmap in conformity with the country’s current socio-economic situation.
- **Sector governance and regulation:** The law mandates the Ministry of Industry (now the Ministry of Industry and Trade - MOIT) to govern the power sector. It also stipulates the

Prime Minister to establish the electricity regulatory agency under the MOIT, with the following main functions:

- Advising on power market structure and industry restructuring policy;
- Development and regulation of power markets;
- Economic regulation (electricity pricing);
- Monitoring power supply-demand balance to promote energy security, efficiency and conservation;
- Licensing and dispute resolution for electricity activities.

The Electricity Regulatory Authority of Viet Nam (ERAV) was established in October 2005 in pursuance of the above law.

The reforms mandated by the Electricity Law aim at satisfying growing demand in a sustainable manner, deliver reliable and high quality electricity supply to support economic growth in the country, while also ensuring reasonable and fair revenues to investors with efficient and transparent costs to consumers. The expected outcomes of the reform program are to attract foreign investment, enhance electricity supply security and transition towards a regime of efficient and market-reflective electricity prices.

The intended outcome of the reform process is to attract investment from foreign and non-traditional sources, as well as to improve the management and operation of the electricity industry as a whole. A key part in the reforms process was the transition towards electricity tariffs that, on the supply side, enable the financial viability of efficiently managed and operated companies, and on the demand side, that provide pricing signals that encourage more efficient use of electricity.

The 2004 Electricity Law was supplemented with a set of amendments and revisions in 2012; nevertheless, the set forth sector reform path has remained intact.

G.2 2006 Electricity Industry Reforms Roadmap

To implement the Electricity Law, the Prime Minister approved the roadmap, and the conditions for establishing and developing a competitive electricity market in Viet Nam in Decision No. 26/2006/QD-TTg dated 26 January 2006 (“Decision 26” or “Roadmap”). The Decision 26 envisaged Viet Nam’s electricity market would be established and developed in 3 phases:

- Phase 1 (2005 - 2014): Competitive electricity generation market

  In this phase, a Single buyer market model for competitive electricity generation would replace the current system of State monopoly and subsidies.

- Phase 2 (2015 - 2022): Competitive electricity wholesale market

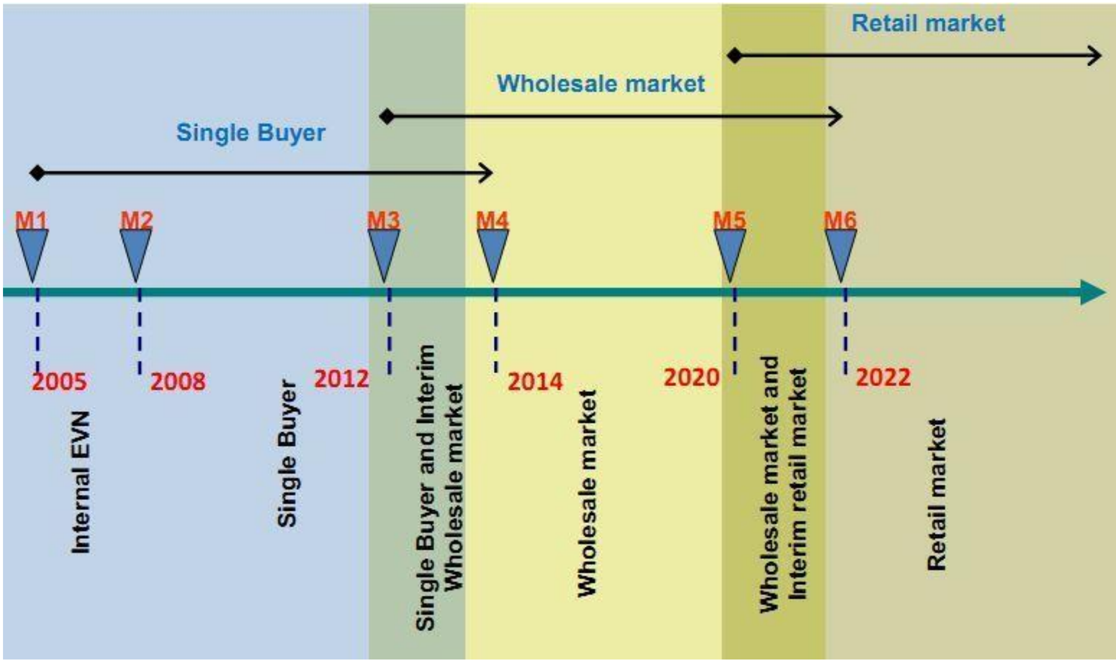
  The power distribution companies (PCs) owned by the Electricity of Viet Nam Group will be allowed to directly buy electricity from generation entities. The generation entities, in turn, will compete to sell to these PCs. The wholesalers would also compete to sell to the PCs and large wholesale customers.

- Phase 3 (from 2022 onwards): Competitive electricity retail market

  In Phase 3, eligible customers will be allowed to choose electricity suppliers (retailers) that best suit their demand or purchase electricity directly from the spot market.

Each market development phase would envisage an initial pilot stage before full implementation. Full details of all proposed milestones of this roadmap are shown in Figure 67.

Figure 67 2006 Electricity Market Roadmap



The roadmap also set out other areas of reforms as follows:

- Restructuring the organisations in electricity industry as prerequisites for each market phase so they can support the operation of a competitive electricity market, eliminate potential conflicts of interest due to cross-ownership between buyers, sellers and other aspects of the industry. Thus, to progress market reforms, EVN would need to be restructured to separate buyers, sellers and service provider entities;
- Introducing an electricity tariff setting mechanism that reflects efficient costs in the supply chain, including power purchase costs in a competitive electricity market, and regulated network and system operation services; and
- Establishing the legal framework and institutions to support energy efficiency, policy to promote the efficient use of electricity and programs to reduce electricity consumption on the demand-side of the industry.

G.3 2006 Electricity Reforms Roadmap Implementation

Despite some delays relative to the proposed timelines, Viet Nam has made important progress in implementation of the Electricity Law and the 2006 roadmap. Below we have summarised the main changes / achievements with respect to the power sector restructuring, the commercial aspect (market design and operations) and the regulatory aspect that covers the legal framework developed for the new market environment.

G.3.1 Summary of main achievements

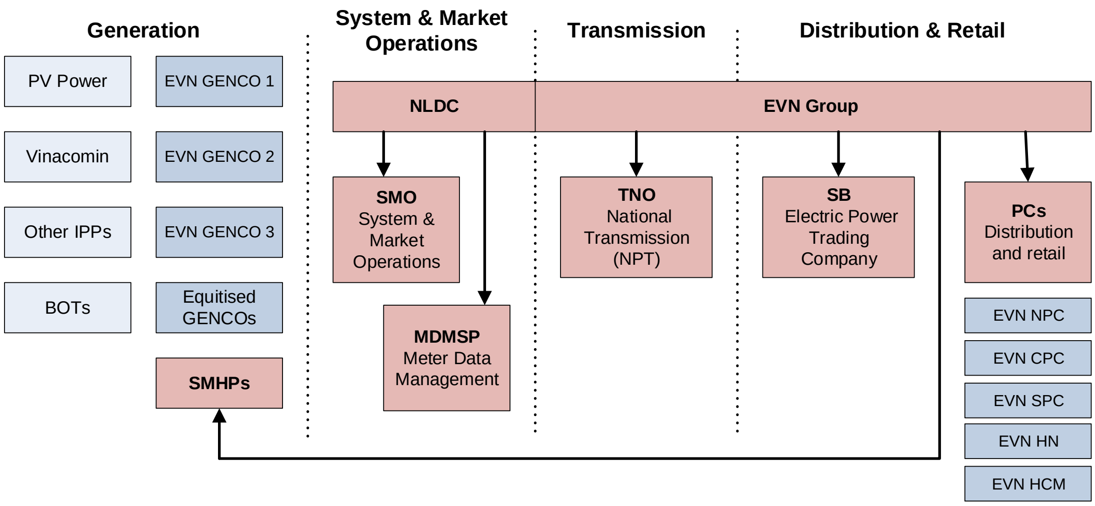
The main achievements with respect to the power sector restructuring, the commercial aspect (market design and operations) and the regulatory aspect that covers the legal framework developed for the new market environment were:

- More diversified ownerships in power generation with greater participation from private investors as well as other non-EVN companies including PetroVietnam (PVN) via its subsidiary PV Power and Vinacomin (TKV);
- Establishment of 3 GENCOs by regrouping EVN owned power plants (in June 2012) for achievement of a more competitive structure in the generation segment;
- New entities established and given new responsibilities to accommodate an electricity market. This includes the establishment of the National Power Transmission Corporation (NPT) as the TNO and the Electricity Power Trading Company (EPTC) as the Single Buyer;
- The VCGM as a single buyer model of generation competitive market was designed and put in operation from July 2012. The VCGM unique features in cost-based pricing and limiting participants' exposure to market prices by no more than 10% have been some essential tools for the MOIT to control the pace of the market evolution without it running away and leading to problems;
- Regulatory and legal frameworks improved to accommodate a market, with the role and functions of the regulatory authority (ERAV) firmly set and reinforced over time. Main legislations promulgated to govern the electricity market include the VCGM Rules and Procedures, Grid Code, Metering Code and the regulations covering PPAs;
- Modern ICT systems established to facilitate the market operations;
- The NLDC (SMO) and other market participants (generators, TNO) starting to gain understanding of market mechanisms in their processes, which is an important prerequisite for transition to the next phase of the wholesale competition.
- Market participants gained experience in operating under the new arrangements.

G.3.2 Overall structure of the electricity industry

The goal of the market reform roadmap was to establish the rules and procedures for a single-buyer electricity market, unbundle and restructure EVN, and to develop the systems and infrastructure necessary to support the operation of an electricity market. Figure 68 below illustrates the general structure of Viet Nam's electricity industry that has evolved since the commencement of the Viet Nam Competitive Generation Market (VCGM) in 2012.

Figure 68 Structure of Viet Nam's Electricity Industry under the VCGM



G.3.3 More diversified ownership in generation

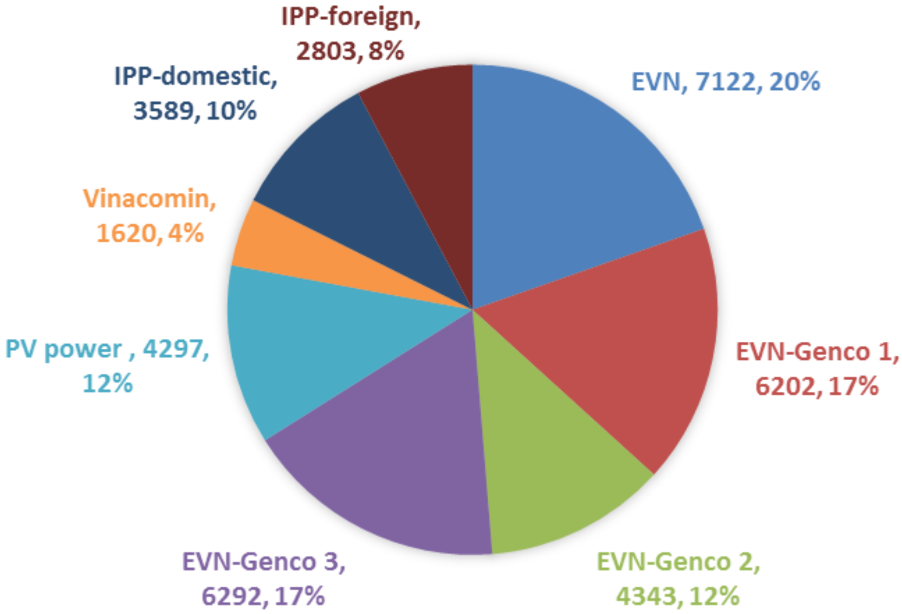
The electricity market reform has seen a wider participation of investors into the generation segment, highlighted as follows:

- Generation investment from other state-owned companies, notably PetroVietnam (PVN) via its subsidiary PV Power and Vinacomin (TKV).
- Moree private and foreign investor -owned generators into BOT and IPP plants.
- Further privatisation of EVN-owned plants to create a number of joint-stock companies (JSCs). This equitisation was largely carried out in the period 2005 to 2009 and included including Vinh Son-Song Hinh Hydro Power Plant, Thac Ba Hydro Power Plant, Pha Lai Thermal Power Plant, Ninh Binh Thermal Power Plant, Danhim–Ham Thuan–Dami Hydro Power Plant, Thu Duc Thermal Power Plant, and Thac Mo Hydro Power Plant.

Restructuring has also taken place among EVN owned power plants. On 1 June 2012, in order to create a competitive industry structure, MOIT approved the establishment of 3 GENCOs with comparable sizes and technology mix to manage generation assets that were directly owned by EVN and by the joint-stock companies (JSCs).

As of the end of 2015, the total installed generation in Viet Nam was 38,409 MW with the breakdown in capacity ownership shown in Figure 69. EVN owns approximately 60% of the total installed generating capacity, either directly (20%) or through its 3 power generation companies (46%). The other main groups of owners of generation capacity are the state-owned PV Power (12%), TKV Power (4%) and foreign Build Own Transfer (BOT) projects and Joint Stock Companies (18% combined). Viet Nam is also dependent on power imports from China and imports power from a hydro project in Laos (Xekaman 3 Hydo).

Figure 69 Generation Capacity by Ownership (MW as at 2015)



Source: EVN 2016

G.3.4 Establishment of the National Power Transmission Corporation (NPT)

The National Power Transmission Corporation (NPT) is a transmission operator incorporating four transmission companies, each of which was previously responsible for managing transmission assets (at 220 kV & 550 kV) in its franchise area. As the sole transmission owner, the NPT's responsibilities include operating transmission facilities according to the Market Rules and Grid Code, coordinating and maintaining assets, assuring conformance with quality of service standards.

G.3.5 Establishment of the Electricity Power Trading Company (EPTC)

The Electricity Power Trading Company (EPTC) is the single buyer operating as an EVN subsidiary during the tenure of the competitive generation market. It is a special wholesaler and enters into power purchase agreements with generators in accordance with relevant rules and regulations. EPTC is responsible for compiling, on an ongoing basis, current and forecast demand data and information from the distribution companies; procuring power to meet the forecast demand on a least-cost basis, including conducting competitive solicitations for new generation capacity, and signing the contracts for differences with direct trading generation in the MOIT issued standard form; honouring power purchase agreements with independent power producers, and procuring remaining power requirements from the spot market backed by bilateral contracts for differences as appropriate.

G.3.6 Consolidation of the regional Power Corporations (PCs)

EVN has five Power Corporations that are subsidiaries and that operate as independent Single Member LLCs and that take the role of power distribution and retail supply. They are responsible for both distribution and retailing as these functions are not presently separated in Viet Nam.

The PCs are:

- NPC, which is in charge of electricity distribution and retail in Northern Viet Nam including 27 cities and provinces (but excluding Ha Noi city);
- CPC, which is in charge of electricity distribution and retail in Central Viet Nam, including 13 cities and provinces;
- SPC, which is in charge of electricity distribution and retail in Southern Viet Nam, including 21 cities and provinces (excluding Ho Chi Minh city);
- Hanoi Power Corporation (HPC) is in charge of distribution and retail in Hanoi capital; and
- Ho Chi Minh Power Corporation (HCMPC), which is in charge of distribution and retail in Ho Chi Minh City.

The establishment of the five PCs follows the restructuring and consolidation of distribution and retail businesses in 2009. Each PC essentially co-ordinates the operation of many smaller provincial distribution utilities called Power Companies (PCOs) within geographic proximity to one another. Each PC maintains a monopoly to supply and sell electricity to their customer base. In addition to the five PCs, which supply the bulk of Viet Nam's customer base, there are a number of independent and privately owned local and rural distribution companies that are also involved in distribution mostly to smaller communities and more remote areas.

PCs own and operate all of the distribution networks from 110 kV and below (except for a small number of 110 kV lines that are owned / operated by the transmission company, NPT), the local distribution networks, and the connections to end-users. They are responsible for metering and billing of consumers, with revenues ultimately flowing back to NPT, EVN (EPTC) and the other generators.

G.3.7 New commercial arrangements

As a major milestone in the roadmap, the VCGM commenced its full operation in July 2012, after a 12 month period of trial operations. This followed the MOIT approval of the market design and market rules that had been in development by ERAV since 2006.

The VCGM set out a new electricity trading model in generators dispatch and contracting with the introduction of a spot market. It is a cost based pool with the following operational principles:

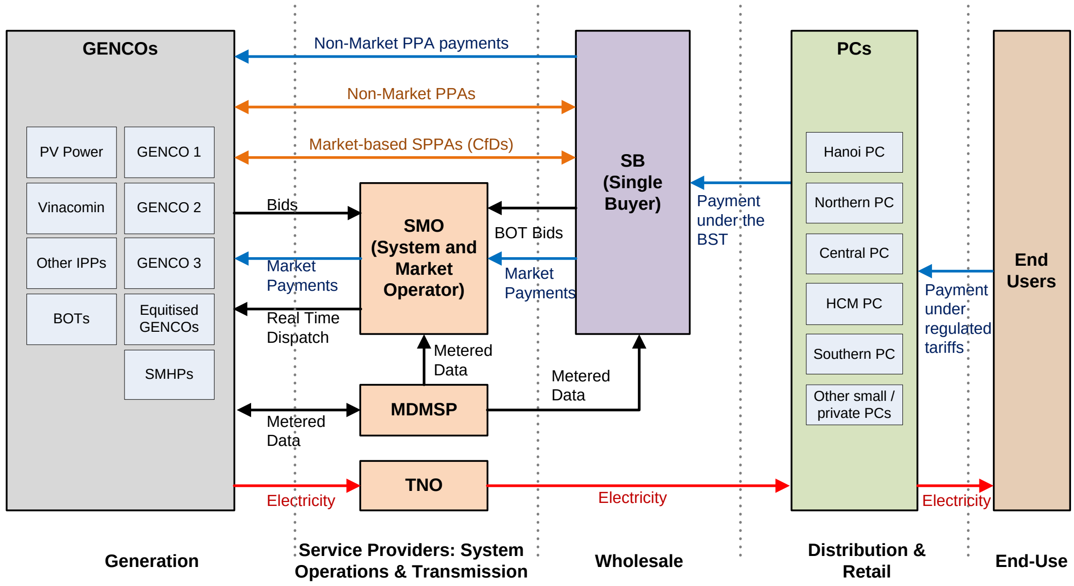
- mandatory participation for grid-connected generators with capacities exceeding 30 MW, with some exceptions: geothermal generators, wind generators and Build-Operate Transfer (BOT) plant that have long-term PPAs in place or that are presently under negotiation;
- all electricity generated by power plants is sold to the Single Buyer (EPTC); the dispatch schedule of generation units is set up by the SMO for each trading interval, based on the variable cost-based bids generation bids, forecasted system load and the available

capability of the transmission network following the principle of minimising the total power purchasing cost;

- the spot market has a trading interval of one hour;
- payments to generators participating in the VCGM are based on the contract prices for VCGM contract for differences (CfDs) called Standard Power Purchase Agreements (SPPAs) and the Full Market Price (FMP) for each trading interval;
- the SPPAs are CfDs written around the FMP; the FMP is the sum of the System Marginal Price (SMP) for energy and a Capacity Add-on (CAN) price for capacity, the contract quantities are centrally determined by SMO based on year-ahead and month-ahead models and contract prices are determined through a negotiation process between project proponent and the Single Buyer, EPTC (the next subsection provides more detail); and
- the proportion of electricity procured at the SPPA contract prices in the first year of the market was to be set in the range of 90% – 95% of the total electricity generated by the plant; the remaining was to be procured at the spot market price. This proportion of generation procured at the spot market price may be adjusted by ERAV based on their assessment of the competitiveness in generation.

An illustration of the main features of the VCGM is given in Figure 70.

Figure 70 VCGM Cost-Based Pool Market Structure



Source: IES

G.3.8 New regulatory framework

Since the inception in 2006, ERAV has assumed the role of the regulator for the VCGM in particular and the operation of the entire electricity sector in general. ERAV has developed and proposed to MOIT or the Prime Minister for approval / issuance of legal documents necessary to oversee and regulate the sector. The legal framework that is managed by ERAV includes the following main areas and legislations:

- VCG Operations
  - Market Rules and Procedures
  - Market Monitoring
  - Dispute Resolution
- Technical Codes
  - Grid Code
  - Distribution Code
  - Metering Code
- Market IT Infrastructure
- Generation Pricing and Charges
  - Method for Generation Price Determination for Standard PPAs
  - Method and Process for Setting up and Publication of Generation Price Band
  - Transmission Charges
  - System and Market Operation Fees
  - Avoided cost tariffs for small hydro plants
- Retail Tariffs and Fees
  - Average electricity retail tariff calculation and adjustment
  - Retail tariff adjustment with market-based mechanism

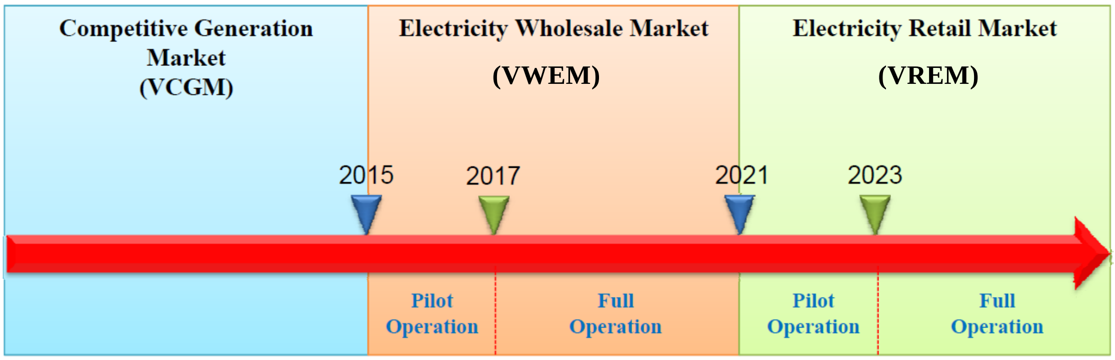
G.4 2013 Electricity Industry Reforms Roadmap

To adjust the market development milestones and fine tune specific development conditions taking into the actual outcome of the VCGM phase, the roadmap for implementation of the competitive power market was reviewed and revised in 2013 as set out in the PM's Decision No. 63-2013-QD-TTg. As illustrated in Figure 71, the new roadmap is a 20 year implementation plan for gradually transforming Viet Nam's electricity industry into one that allows for competitive wholesale and retail electricity markets. This defines a time line for transitioning between three major stages of reform:

- Viet Nam Competitive Generation Market (VCGM);
- Viet Nam Wholesale Electricity Market (VWEM), and
- Viet Nam Retail Electricity Market (VREM).

Each stage commences with a pilot period, with a number of constraints defined, which is subsequently followed by a "full operation" period.

Figure 71 Electricity Industry Reform Roadmap (2013)



Source: ERAV

The Roadmap defines the following broad principles for the VWEM[60]:

- Operational principles (Article 7):
  - Power Corporations may purchase power from generators via bilateral contracts and to purchase from the spot market;
  - Generators may sell electricity to power corporations, and eligible large customers via bilateral contracts and to sell to the spot market;
  - Large customers satisfying specific conditions may purchase power from generators or power corporations under bilateral contracts or directly from the spot market;
  - New trading entities may be established to purchase and/or sell electricity;
- Power sector sstructure (Article 8):
  - In the VWEM Pilot period, the following restructuring will be required:
    - SMO shall be an independent entity, and will share no interests or benefits from market participants;
    - EVN's generators (apart from the strategic power plants) will become independent GENCOs and will share no interests or benefits with the SMO, transmission system operator, or any newly created trading entities in the VWEM;
    - The total installed capacity of any single generator in the VWEM will not exceed 25% of the total installed capacity[61];
    - Eligible PCs will be required to separate their retailing and distribution functions and set them up as independent accounting units;
  - Under full operation of the VWEM, power companies operating under the PCs will be required to separate their distribution and retail functions and assign these to separate independent accounting units;
- Preconditions to be satisfied before VWEM (Article 9):

[60] Note that this has been paraphrased from the content of Decision No. 63, in light of discussions with ERAV on the meaning and interpretation.
[61] Note that the consultant views 25% to be too high, 15% would be more appropriate.

- Legal framework preconditions:
  - Power sector restructuring plan approved by the Prime Minister;
  - VWEM detailed design approved by MOIT;
  - MOIT promulgates or amends the following regulations:
    - Regulations governing VWEM participants;
    - VWEM rules;
    - Regulations on electricity regulatory regimes, grid codes, distribution code, metering code;
    - Regulations on transmission pricing, distribution pricing, SMO fees, trading operation charges;
    - Any other regulations that may be necessary and applicable to the operation of the VWEM;
- Infrastructure to support the operation of the VWEM:
  - SCADA/EMS upgrade completed, remote metering systems for all independent accounting distributors and large customers to be in place, and infrastructure to generally satisfy any VWEM standards or VWEM requirements;
  - IT systems equipped to support market operations in line with the requirements of the VWEM;
- VWEM participants have been staffed with trained human resources that understand the new environment and also the infrastructure to support the operation of the VWEM;

Prior to the full operation of the VWEM, the legal framework and system infrastructure shall satisfy the full VWEM standards and requirements.

G.5 2013 Electricity Reforms Roadmap Implementation

G.5.1 Industry restructuring

To achieve the power sector structure envisaged in the roadmap, ERAV / MOIT have studied and proposed the Restructuring Plan for the Electricity Industry for the period 2016 to 2020 with outlook toward 2025. The plan was approved by the Prime Minister in February 2017 at Decision No 168/QD-TTg. Main contents of this legislation are of this summarised as follows:

- Objectives:
  - Enhance the effectiveness of the electricity sector in line with the continual transition to market mechanisms, and strengthening the transparency, equality, and fair competition.
  - Establish the structure of the electricity sector to facilitate the operation of the wholesale electricity market and the retail electricity market in future.
  - Improve the effectiveness of the electricity regulation in ensuring the sustainable electricity system.

  - Implement electricity prices in line with the market mechanism appropriate to each electricity market phase.
- Generation Restructuring:
  - By 2018, state-owned generation corporations including EVN Gencos, PV Power and TKV generators will be equitised, with the parent groups retaining at least 51% controlling equity.
  - By 2020, the state-ownership in these Gencos will be reduced to less than the controlling level, and the Gencos will be fully separated from their current parent groups (e.g. EVN, PVN, TKV).
- Market and System Operation:
  - Restructure the current EVN-subsidised NLDC into an Independent SMO owned by EVN by 2020 before the commencement of the full VWEM.
  - Propose to fully separate the SMO from EVN in the period 2021-2025.
- Distribution and Retail:
  - Commence separation of distribution and retail accounting in the PCs in the period 2019-2020.
  - Continue the separation of distribution and retail businesses in the period 2021-2025.
  - Propose to equitise the retail arms in the PCs.

G.5.2 Commercial arrangements – VWEM design

On 10th August 2015, the MOIT approved the Detailed Design of the Wholesale Electricity Market of Viet Nam (VWEM). The decision applies to the Pilot VWEM and the Full VWEM. The key aspects of the MOIT decision with respect to trading arrangements are:

- Greater participation of all generating units over 30MW in the VWEM with the aim of all BOTs and SMHPs participating directly or via a trader;
- The participation of electricity buyers in the VWEM; and
- Creation of service providers: System and Market Operator (SMO), Electricity Transmission Service Provider (ETSP), Electricity Distribution Service Providers (EDSPs) and Meter Data Management Service Provider (MDMSP).

The Full VWEM (2019-21) will allow all eligible customers and wholesalers who meet the defined requirements to participate in the VWEM.

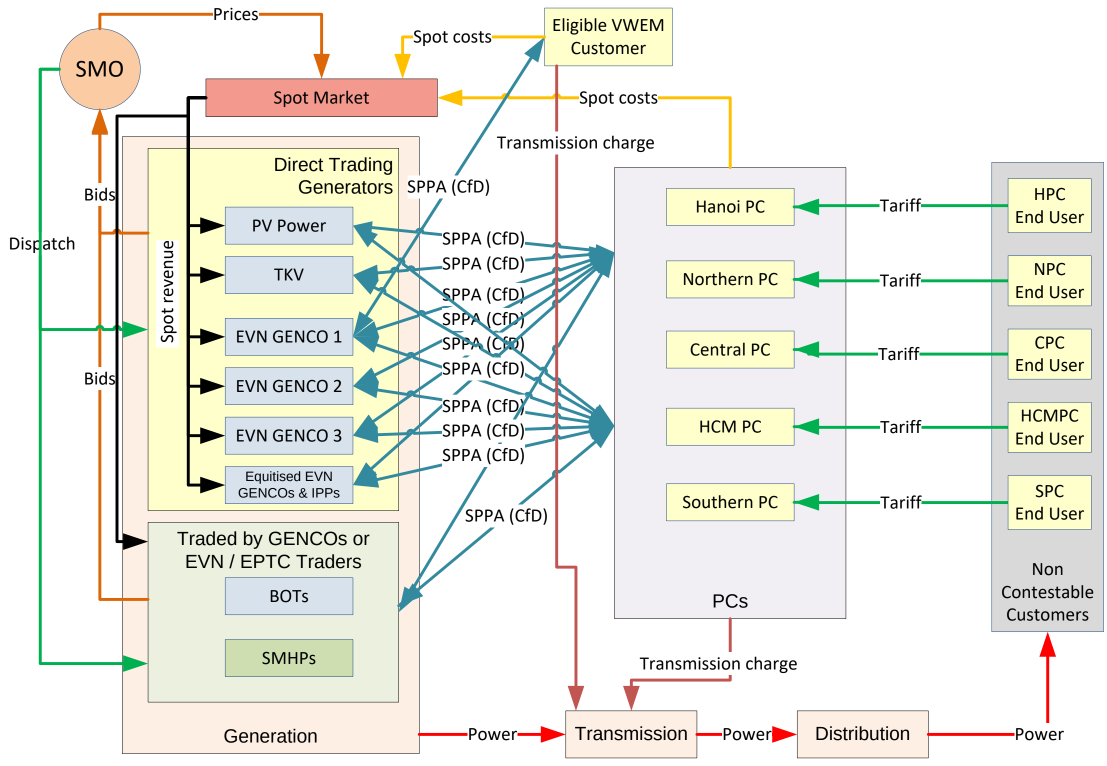
The proposed trading arrangements for the VWEM are designed to have the PCs contract directly with generators and change the role of the Single Buyer (EPTC) in the market. The VWEM, also allows for wholesalers to enter the market and contract with generators and then sell to PCs (contract with PCs). The MOIT's approved VWEM design allows for the possibility of having eligible customers being allowed to contract directly with generators or PCs other than their current PC. An eligible customer is either an existing or new customer that is connected (or that would connect) to the transmission network[62] and hence needs to be considered as part of the wholesale market. Eligible customers would be subject to transmission charges. All other customers would be considered as part of retail market, an issue for the VREM. The design allows for new retailers to enter the market and sell to eligible customers.

The intended result of the VWEM over time is for:

- PCs to enter into contracts directly with generators such that their total contract portfolio should largely match their load profiles; and
- Where mismatches between their contracts and actual demands occur, PCs will face some spot market exposure.

For this stage transmission charges and possibly distribution charges will be unbundled. Thus the power costs for a PC over time will change from the Bulk Supply Tariff (BST) to a combination of transmission charges, contract difference payments (SPPAs) and spot market payments. These arrangements are illustrated in Figure 72.

Figure 72 Outline of VWEM Trading Arrangements



[62] The Grid Code defines the transmission system in Viet Nam to include "all power lines and substations at 220 kV or greater voltage levels, and 110kV power lines and substations that have a power transmission function to receive electricity from generators and inject it into the national power system".

G.5.3 VWEM stages

The VWEM design envisaged the implementation steps ac activities involved in each step as follows:

1. First step of Pilot VWEM in 2016 (paper market), which includes:

- Maintaining the VCGM actual operation while new VWEM arrangements of VWEM (vesting contract allocation, market settlement, cross-subsidy, etc…) are modelled on paper.
- Developing the necessary legal framework including the VWEM Rules and other regulations.
- Reforming the electricity sector in accordance with the restructuring proposal and Roadmap approved by the Prime Minister.
- Developing the ICT infrastructure system.
- Conducting the training for market participants.
- Assessing the outcomes of on-paper Pilot VWEM to make necessary adjustments in the second step of Pilot VWEM.

2. Second step of Pilot VWEM in 2017-2018:

- Testing the VWEM arrangements in real operations.
- Revising, completing the VWEM Rules and relevant regulations.
- Continuing the sector reform in accordance with the Proposal and Roadmap approved by the Prime Minister, which includes the transformation of NLDC into an independent accounting unit under EVN.
- Completing the development of the ICT infrastructure system that includes the set-up and testing of a new MMS system.
- Continuing the training for market participants
- Assessing the outcomes of the second step of Pilot VWEM to make necessary revisions of VWEM's arrangement (if required).

3. Full VWEM from 2019.

G.5.4 Regulatory framework

ERAV has managed the issuance of legislations on the VWEM design and implementation. They are also working on finalisation of the WVME Rules and have updated or in the process of updating other rules and codes for consistency with the VWEM operation.

G.6 Implications of Electricity Industry Reforms for Gas Market Roadmap

From the above Case Study on the Viet Nam Electricity Industry Reforms, the following implications can be drawn for our proposed Gas Market Roadmap:

- Directions, main strategies and objectives of the industry reform are formulated in high level policy documents such as laws: The Electricity Law has mandated the establishment and development the power market in Viet Nam. The roadmap would then detail an action plan to implement the overall policy set forth.

- The roadmap contains well-defined phases with prerequisites to be met against each of the specific aspects pertinent to the industry operation such as the organisation structure, trade arrangements and legal / regulatory frameworks.
- Maintain a slow, gradual but steady pace of reforms with the application of ,2/. Use of Pilot and Full Market stages as a way of gaining experience and evaluating progress, and avoiding a "step-change" to the industry. Gradual transitions between stages would also give time for legal and regulatory frameworks and legal framework to accommodate market mechanisms and be tested on their robustness.
- Building a market on top of existing arrangements rather than wiping out existing tools / processes and replacing with an entirely new market. In particular, the VCGM which was a major step in the transition towards a wholesale electricity market, was an example of largely using existing systems and resources to start a market. This was only a small change from the current dispatch operations.
- Conduct step reviews of the roadmap and make adjustments and improvements as needed but maintain the broad reform path intact as it has been originated on justified principles. The 2013 updated electricity roadmap showed how experience gained was leveraged to improve the plan but the general market development direction and stages remained unchanged.
- Implementation of the roadmap would result in actual changes to the way the industry operates, for example in regard to the organisation structure. The creation of the three EVN GENCOs and the PM's approval of further restructuring for the power sector have been some significant outcome of the electricity reform roadmap to date.
- Having a dedicated regulatory entity for the industry is essential in ensuring the roadmap is properly implemented and monitored.