DEVELOPMENT OF A LIFE CYCLE COSTING MODEL FOR LIQUEFIED NATURAL GAS PRODUCTION SYSTEM

BY

Ebitei CHARLES

MATRIC. NO.: 131333

B. Tech (Hons). Aeronautical Engineering and Design (Loughborough),

M.Sc. Mechanical Engineering (Lagos),

M.Sc. Operations Research (Lagos),

MBA Production and Operations Management (LASU)

A Thesis in the Department of Industrial and Production Engineering,
Submitted to the Faculty of Technology
in partial fulfillment of the requirements for the Degree of

DOCTOR OF PHILOSOPHY

of the

UNIVERSITY OF IBADAN

JULY, 2023

CERTIFICATION

I certify that this work was carried out by Engr. Ebitei CHARLES in the Department of Industrial and Production Engineering, University of Ibadan.

Supervisor
O. E. Charles-Owaba
B.Sc. (Hons), M.Sc., Ph.D. (Texas)
MNSE, COREN Regd.
Professor, Department of Industrial and Production Engineering
University of Ibadan, Ibadan

Co-Supervisor
I. E. Edem
B.Sc. (Uyo), M.Sc. (Ibadan), Ph.D. (LAUTECH)
MNSE, COREN Regd.
Lecturer, Department of Industrial and Production Engineering
University of Ibadan, Ibadan

DEDICATION

To my late parents, brothers and sisters who spearheaded my early education.

ACKNOWLEDGEMENTS

Many people have contributed in various ways toward the successful completion of this work.

I would like to specially express my gratitude to:

Prof O.E. Charles-Owaba (Thesis Supervisor) for his much-needed help and guidance, and for painstakingly going through the entire manuscript and making corrections as well as suggestions for the overall improvement of this thesis. He provided me with his time, space, confidence, love, continued interest, and encouragement throughout this study.

Dr I. E. Edem (Co-Supervisor) for his guidance, detailed review and analysis of this work; and in particular providing me with the software for the analysis and some of the texts I needed for the literature review.

I am very grateful to the entire staff of the Department of Industrial and Production Engineering for their love, patience and assistance.

I am also much indebted and grateful to Mrs. Charles-Owaba for her prayers, encouragement, and ever-ready assistance when much needed.

Finally, I owe my sincere gratitude to my wife and children for their understanding, encouragement, support and patience during the duration of this study.

ABSTRACT

Despite the large natural gas reserve in Nigeria and increasing global demand for Liquefied Natural Gas (LNG), prospective investors appear hesitant in doing LNG business in Nigeria. One major reason is that the existing LNG business cost estimation models are inadequate to incorporate various business factors such as long life-span risky events and capital intensiveness. A Life Cycle Costing (LCC) model was developed to accommodate these factors using System Dynamics (SD) principles.

Ten LNG business firms operating in Nigeria and abroad were studied and seven randomly selected stakeholders interviewed for insights on LNG business processes. Operating sectors were identified using SD principles. Input and output sector quantities and their inter-relationships were determined using system causal loop, while flow diagramming approach was used to characterise the LNG value chain operations. The LNG-process equations were formulated in terms of plant availability, production workforce capability and shipment delivery rate. These were synthesised to evolve an SD-LNG-LCC model. The model was applied to predict a set of twenty-one year (1999-2019) values of LNG volume shipped and revenue. These were compared to the actual values obtained from an LNG-firm in West Africa. The firm's LCC, Unit Production Cost (UPC), Return on Investment (ROI), Net Present Value (NPV) and Profitability Index (PI) were also obtained. The viability of the firm's Greenfield-Brownfield investments and the model's performance were further evaluated using different scenarios of NG base-prices. Data were analysed using student t-test at $\alpha_{0.05}$.

The identified operating sectors were production, maintenance and finance. Capital and operating expenditures; NG-LNG prices; Train-Capacity; equipment and spares; planned manpower; maintenance-effectiveness; discount-rate, and equipment-failure probabilities were identified sector input quantities, while LCC, production volume, revenue, return on investment, payback period, discounted profit, equipment availability were the outputs. Plant availability, production workforce capability and shipment delivery rate were 0.90, 2310.92 m^3gas/man-hour and 6 deliveries/shipyear, respectively. The model predicted LNG volume shipped was $(13.46\pm0.02)\times10^9$ tonne per annum (TPA) while the firm's actual value was $(13.62\pm0.02)\times10^9$ TPA. Similarly, the revenue from the predicted and actual were (₦864.00±572.43)$\times10^9$ [(\$5.40±3.58)$\times10^9$] and (₦870.40±561.14)$\times10^9$ [(\$5.44±3.51)$\times10^9$]. These indicated that there was no significant difference between the predicted and actual values. The firm's LCC, UPC, ROI, NPV and PI were ₦10000.00$\times10^9$ (\$62.50$\times10^9$), ₦662.40 (\$4.14) per MMBTU, 26.01%, ₦2369.60$\times10^9$ (\$14.81$\times10^9$) and 1.59, respectively. For expansion alternatives, the Greenfield LCC was ₦109264.60 [\$682.91] per tonneyear relative to the Brownfield's ₦76235.20 (\$476.47) per tonneyear. In model sensitivity, 50% increase in NG base-price yielded LCC of ₦7359.80$\times10^9$ (\$45.98$\times10^9$) compared to ₦12640.20$\times10^9$ (\$79.02)$\times10^9$ yield by a 150% increase.

A liquefied natural gas life cycle costing model was developed using system dynamics principles. The developed model is a useful instrument for determining costs and decision support for liquefied natural gas project investments.

Keywords: Liquefied natural gas, Causal loop diagram, Life cycle costing, System dynamics modelling

Word count: 445

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ABBREVIATIONS

Abbreviation	Meaning
AMW	Active Maintenance Workers
B	Brownfield
BOG	Burn-Off-Gas
BPDC	Brownfield Plant Design Capacity
BScf	Billion Standard Cubic Feet
BScm	Billion Standard Cubic Metre
CAPEX	Capital Expenditure
CEPCI	Chemical Engineering Plant Cost Index
CF	CAPEX Fund
CM	Corrective Maintenance
CO	Customer Order
CPP	Current Plant Capacity
CT_j	Compressor/Expander of class type J
DFDEe	Dual Fuel Diesel Electric Engine
Dmnl	Dmnl
DP	Depreciation
EBIT	Earnings Before Interest and Tax
EMF	Equipment Maintenance Fund
G	Greenfield
GPDC	Greenfield Plant Design Capacity
FAF	Fund Availability factor
FF	Funding Factor
FIL	Fund Implementation Level
FG	Feed gas
FLF	Fund Leakage Factor
FuG	Fuel gas
GE	Gas Equivalent
HFO	Heavy Fuel Oil

Abbreviation	Meaning
IC	Interest on Capital
ID	Inventory Delay
IHC	Inventory Holding Costs
INT	Integer
IOC	Inventory Ordering Cost
IUC	Inventory Utilisation Cost
Kt	Knot
Lab	Labour
LNG	Liquefied Natural Gas
LE	LNG Equivalent
MAPE	Mean Absolute Percentage Error
Max.	Maximum
MEA	Model Evaluation Approach
Min.	Minimum
MMA	Maintenance Manpower Availability
MMBTU	Metric Million British Thermal Unit
MMC	Miscellaneous Maintenance Costs
MScm	Million Standard Cubic Metre
MT	Million Tonne
Mtce.	Maintenance
MTPA	Million Tonne Per Annum
MW	Megawatt
NG	Natural Gas
NGL	Natural Gas Liquids
OH	Overhead/Other
OPEX	Operational Expenses
PPLR	Perceived Plant LNG Requirement
PDC	Plant Design Capacity
PFHE	Plate Fin Heat Exchanger
PM	Preventive Maintenance

Abbreviation	Meaning
PO	Production Order
POP	Plant Operating Period
POW	Plant Operation Window
PP	Production Personnel
PPLR	Perceived Plant LNG Requirement
PPNG	Piping
RAM	Reliability, Availability and Maintainability
ROI	Return On Investment
SPA	Sales and Purchase Agreement
STCe	Steam Turbine Carrier Engine
SWHE	Spiral Wound Heat Exchanger
TA	Turnaround
TTPM	Time to Preventive Maintenance
TTTA	Time to Turnaround
UF	Unplanned Failure

LIST OF SYMBOLS

Symbol	Definition	Unit
V_{order}^{cust}	Accumulated Customer Orders	m^3
V_{Acc}^{PO}	Accumulated Production Orders	m^3
f_{PAsign}^{WAct}	Active Production Personnel (PP) Assignment Factor	1/Time
f_{PTerm}^{WAct}	Active PP Assignment Termination Factor	1/Time
W_{Prod}^{Act}	Active PP	Man
f_{PFire}^{WAct}	Active PP Firing Frequency	1/Time
$\dot{W}_{PFire}^{Act}$	Active PP Firing Rate	Man/Time
$\dot{W}_{prod}^{ActIn}$	Active Production Personnel In Flow	Man/Time
$\dot{W}_{prod}^{ActOut}$	Active Production Personnel Outflow	Man/Time
W_{MtceS}^{Act}	AMW	Man
W_{Mtcek}^{Act}	AMW for Equipment type k $[E_k]$	Man
$\dot{W}_{Mtcek}^{ActIn}$	AMW In for E_k	Man/Time
$\dot{W}_{Mtcek}^{ActOut}$	AMW Out for E_k	Man/Time
C_{XMtce}^{Annual}	Annual Equipment Maintenance Expenses	$/Year
C_{XLFD}^{Annual}	Annual OPEX (Less FG and DP Costs)	$/Year
P_{CF}^{xLFD}	Annual OPEX (Less FG and DP Costs)/CAPEX Ratio	%/Year
C_{XLFuFD}^{Annual}	Annual OPEX (Less FuG, FG and DP Costs)	$/Year
P_{CF}^{xLFuFD}	Annual OPEX (Less FuG, FG and DP Costs)/CAPEX Ratio	%/Year
W_{Mtcek}^{Ass}	Assigned Maintenance Workers for E_k	Man
$\dot{W}_{Mtcek}^{AssIn}$	Assigned Maintenance Workers Inflow for E_k	Man/Time
$\dot{W}_{Mtcek}^{AssSink}$	Assigned Maintenance Workers Sink for E_k	Man/Time
W_{S}^{Rqst}	Available Labour Requests	Man
V_{SLim}^{LNG}	Available LNG Storage Limit	m^3
V_{SLim}^{LNGge}	Available LNG Storage Limit (Gas Equivalent)	m^3_{gas}
$\dot{W}_{Mtcek}^{AvIn}$	Available Maintenance Labour Inflow for E_k	Man/Time

Symbol	Definition	Unit
W_{Mtcek}^{Av}	Available Maintenance Labour for E_k	Man
$\bar{C}_{Prod}^{Annual}$	Average Annual Production Cost	\$/Year
V_{Even}^{Break}	Breakeven Quantity	m^3_{LNG}
t_{Even}^{Break}	Breakeven Period	Time
B_{Dsgn}^{Cap}	Brownfield Plant Design Capacity (BPDC)	MTPA
V_{Tr}^{B}	Brownfield Unit Train Capacity	MTPA/Train
C_{BM}^{UCap}	Bulk Material Cost Per Unit BPDC	\$/MTPA
C_{GM}^{UCap}	Bulk Material Cost Per Unit GPDC	\$/MTPA
$\dot{W}_{Mtcek}^{CaRqrd}$	Cancelled Maintenance Workers Requirements for E_k	Man/Time
$\hat{B}_{EX}^{C}$	CAPEX Budget	\$
$\hat{F}_{EX}^{C}$	CAPEX Fund (CF)	\$
Ψ_{EX}^{C}	CAPEX Funding Factor	Dmnl
$\dot{F}_{EX}^{C}$	CAPEX Fund Inflow	\$/Time
G_{Cash}^{NPV}	Cash Flow (NPV)	\$
$\dot{G}_{Cash}^{NPV}$	Cash Flow Rate (NPV)	\$/Time
I_{CEPSI}	CEPCI	Dmnl
t_{Trvl}^{Ship}	Charter Travel Time	Day
f_{Ek}^{TecCM}	CM Efficiency for E_k	Dmnl
t_{k}^{CmI}	CM Intervention Period for E_k	Time
f_{Ek}^{LogCM}	CM Logistics Factor for E_k	Dmnl
W_{CM}^{Press}	CM Workforce Pressure	Man
C_{CPmk}^{TotInt}	CM/PM cost per intervention for E_k	\$
C_{CPmk}^{PerInt}	CM/PM Costs Per Intervention for E_k	\$
t_{CPm}^{InvDel}	CM/PM Inventory Delay (ID) Period	Time
t_{CmPmk}^{IDur}	CM/PM Intervention Duration for E_k	Time
$\ddot{C}_{MCPmk}^{Exp}$	CM/PM Maintenance Expense Rate for E_k	\$/Time
f_{CPFrq}^{mtce}	CM/PM Maintenance Frequency	Dmnl

Symbol	Definition	Unit
t_{CPmk}^{WRqrd}	CM/PM Maintenance Man-hour Required for E_k	ManTime
M_{MCPm}^{Ordr}	CM/PM Maintenance Material Order Units	$
W_{CmPmk}^{Rqrd}	CM/PM Maintenance Workforce Required for E_k	Man
$E_{CmPmk}^{\boldsymbol{WMatAv}}$	CM/PM MMA for E_k	Dmnl
$\ddot{C}_{CPmk}^{IntEx}$	CM/PM Periodic Expense per Intervention	$/hour
$\ddot{C}_{CPmk}^{IntCst}$	CM/PM Periodic Costs per Intervention for E_k	$/hour
$\dot{W}_{CmPmk}^{Met}$	CM/PM Periodic Maintenance Workforce Met for E_k	Man/Time
$\dot{W}_{CmPmk}^{Rqrd}$	CM/PM Periodic Maintenance Workforce Required for E_k	Man/Time
$E_{CmPmk}^{MetRqst}$	CM/PM Periodic Personnel Request Met for E_k	Dmnl
E_{CmPmk}^{WRqst}	CM/PM Personnel Request for E_k	Dmnl
f_{RecCm}^{Dec}	CM Recruitment. Decision	Dmnl
C_{CPm}^{TotInt}	CM/PM Total Costs per Intervention	$
C_{xCPm}^{MTot}	CM/PM Total Periodic Maintenance Expense per Intervention	$/Time
$\ddot{C}_{CPm}^{PrdInt}$	CM/PM Periodic Costs per Intervention	$
p_{Crt}	Critical p-value for t-Test statistic	Dmnl
W_{mtce}^{Cgap}	Constrained Maintenance Personnel Gap	Man
W_{Prod}^{Con}	Constrained Workforce for Production	Man/Time
C_{BC}^{UCap}	Construction Cost Per Unit BPDC	$/MTPA
C_{GC}^{UCap}	Construction Cost Per Unit GPDC	$/MTPA
CT_j	Compressor/Expander of class type j	Dmnl
γ_i	Correction index for OPEX funding factor for activity type i	Dmnl
C_{gk}^{MTPA}	Cost of equipment type k per unit MTPA for equipment group g	$
t_{cumk}^{down}	Cumulative Downtime for E_k	Time
P_k	Cumulative failure probability of equipment type k	Dmnl
e_{Cum}^{MAPE}	Cumulative MAPE	Dmnl
t_{cumk}^{Up}	Cumulative Uptime for E_k	Time

Symbol	Definition	Unit
P_{CC}	Current Plant Capacity (CPP)	MTPA
V^{co}	Customer Order	m^3
$f_{Dt^*}^{LNG}$	Customer order fraction	Dmnl
$\dot{V}_{order}^{cust}$	Customer Order Rate	m^3/Time
C_{Source}^{Port}	Daily port charges at source/loading port	$/daytrip
C_{Dest}^{Port}	Daily port charges at destination/unloading port	$/daytrip
f_{RecPm}^{Dec}	Decision for PM Recruitment	Dmnl
f_{RecTaM}^{Dec}	Decision for TA Recruitment	Dmnl
$\dot{E}_k^D$	Degradation Rate for E_k	1/Time
E_k^D	Degradation Level for E_k	Time
$\dot{E}_k^{DR}$	Degradation Reduction Rate for E_k	Time
M_{Del}^{Inv}	Delayed Inventory	$
K_D	Depreciation Consideration factor	Dmnl
$\dot{E}_{xDP}$	Depreciation Expenses Inflow	$/Time
f_{DP}^{Exp}	Depreciation Expense Rate Factor	1/Time
δ^{LNG}	Discrepancy In LNG Inventory	m^3
V_{Du}^{LNGge}	Desired Gas Usage Volume	$m^3{}_{gas}$
V_D^{LNGMT}	Desired LNG Stock (MT)	MT
V_D^{LNG}	Desired LNG Stock	m^3
V_D^{LNGge}	Desired LNG stock (Energy Equivalence)	MMBTU
W_{mtce}^{Dgap}	Desired Maintenance Personnel Gap	Man
W_{Mtce}^{Des}	Desired Maintenance Workforce	Man
t_{MPm}^{Usage}	Desired PM Usage Period	Time
V_{Ds}^{LNGge}	Desired Production Start Volume	$m^3{}_{gas}$
t_{MTa}^{Usage}	Desired TA Maintenance Usage Period	Time
f_{LProd}^{Trnce}	Desired Workforce Lower Tolerance	%
f_{UProd}^{Trnce}	Desired Workforce Upper Tolerance	%
f^{Disc}	Discount Factor	Dmnl

Symbol	Definition	Unit
r^{Disc}	Discount Rate	%/Year
t_{Back}^{Pay}	Discounted Pay Back Period (PBP)	Year
$\ddot{G}_{LNG}^{Disc}$	Discounted Periodic Profit	$/Time
$t_{Load}^{Port}, t_{Unload}^{Port}$	Duration of port activity for shipment loading and unloading respectively	day
t_{Dock}^{Port}	Duration of port activity for dock activities on ship return	day
$\varepsilon_{shipq}^{fuel*}$	Relative fuel efficiency constant for ship propulsion system type q	%
t_{Pm}^{Earlst}	Earliest PM Time	Time
C_{BEpm}^{UCap}	Engineering and Project Management Cost per Unit BPDC	$/MTPA
C_{GEpm}^{UCap}	Engineering and Project Management Cost per Unit GPDC	$/MTPA
C_{BE}^{UCap}	Equipment Cost Per Unit BPDC	$/MTPA
C_{GE}^{UCap}	Equipment Cost Per Unit GPDC	$/MTPA
$\dot{E}_{xMtce}$	Equipment Maintenance Expenditure Flow	$/Time
F_{Mtce}	Equipment Maintenance Fund (EMF)	$
K_{Mtce}^{FF}	Equipment Maintenance Funding Factor (FF)	Dmnl
$\dot{F}_{Mtce}$	Equipment Maintenance Fund Inflow	$/Time
K_{Mtce}^{IL}	Equipment Maintenance Fund Implementation Level (FIL)	Dmnl
K_{Mtce}^{FLF}	Equipment Maintenance Fund Leakage Factor (FLF)	Dmnl
E_k	Equipment Type k	Dmnl
$\dot{t}_k^{down}$	Equipment Type k Periodic Downtime	Time
C_{expd}^{Lube}	Expected Cost of Equipment Lubrication	$
K_{ij}^{E}	Expense fractions for activity type i based on operation class j	Dmnl
C_{Fuel}^{exptd}	Expected fuel cost	$
t_{Exptd}^{lead}	Expected Lead Time	Time
N_{Plan}^{sdwn}	Expected no. of planned shutdowns	Dmnl
N_{Plan}^{sdwn}	Expected number of planned shutdowns	Dmnl
K_{Exptd}^{ProdWC}	Expected Production Workforce Capability	m^3_{gas}/ManTime
W_{Exptd}^{PExe}	Expected Production Workforce Number	Man

Symbol	Definition	Unit
t_{Exptd}^{WLExe}	Expected Workload Execution Time	Time
W_{PExptd}^{Load}	Expected Production Workload	ManTime
W_{prod}^{UReqd}	Expected Production Workforce Requirement per Workload	ManTime/m^3_{gas}
f^{Loc}	Facility Location Factor	Dmnl
P_{Ek}^{Φ}	Failure Probability for Equipment Type k	Dmnl
D_{Feed}^{NG}	Feed Gas Accessibility Delay Signal	Dmnl
$\dot{E}_{xFG}$	Feed Gas Expenses Flow	$/Time
F_{FG}	Feed Gas Fund	$
K_{FG}^{FF}	Feed Gas Funding Factor	Dmnl
$\dot{F}_{FG}$	Feed Gas Fund Inflow	$/Time
K_{FG}^{FLF}	Feed Gas Fund Leakage Factor	Dmnl
K_{FG}^{IL}	Feed Gas Fund Implementation Level	Dmnl
f_{Feed}^{NG}	Feed Gas Supply Frequency	1/Time
t_{Feed}^{NG}	Feed Gas Supply Interval	Time
$\dot{V}_{Feed}^{NG}$	Feed Gas Rate	m^3_{gas}/Time
W_{PFire}^{Act}	Fired Active Prod Operators	Man/Time
f_{ShipqL}^{Avail}	Fraction of shipping vessel on long term charter contract with propulsion system type q	Dmnl
f_{ShipqS}^{Avail}	Fraction of shipping vessel on spot charter contract with propulsion system type q	Dmnl
f_{Prod}^{W}	Fraction of total workforce dedicated to all work functions except maintenance	Dmnl
ω_j	Fraction of total expenses incurred on all activities belonging to operation class j	Dmnl
$f_{FWAt^*b}^{TLNG}$	Fraction of Total LNG sold by the LNGFWA to contracted buyer b in operation period t^*	Dmnl
ϱ_i	Fraction of total OPEX for activity type i	Dmnl
f_{CmPmk}^{Met}	Frequency at which CM/PM Periodic Maintenance Workforce requirement is Met for E_k	1/Time

Symbol	Definition	Unit
f_{Tak}^{Met}	Frequency at which TA Periodic Maintenance Workforce requirement is Met for E_k	1/Time
$\dot{E}_{xFuG}$	Fuel Gas Expenditure Flow	$/Time
F_{FuG}	Fuel Gas Fund	$
K_{FuG}^{FF}	Fuel Gas Funding Factor	Dmnl
$\dot{F}_{FuG}$	Fuel Gas Fund Inflow	$/Time
K_{FuG}^{IL}	Fuel Gas Fund Implementation Level	Dmnl
K_{FuG}^{FLF}	Fuel Gas Fund Leakage Factor	Dmnl
f_{Fu}^{Usage}	Fuel Usage Factor	%
f_{Fund}^{Access}	Fund Access Factor	Dmnl
B^T	Funded Budget	$
$\dot{B}^T$	Funded Budget Inflow	$/Time
K^{GD}	Gas Delivery Capability Factor	Dmnl
V_{Dd}^{LNGge}	Gas Delivery Volume	m^3_{gas}
δ^{NG}	Gas In Process Discrepancy	m^3_{gas}
f_{LNG}^{Gas}	Gas-LNG Converter	m^3_{gas}/m^3_{LNG}
GST_j	Gas separators of class type *j*	Dmnl
$GTHS_j$	Gas treatment heaters of class type *j*	Dmnl
GTD_j	Gas turbine drivers of class type *j*	Dmnl
$\dot{V}_{FuG}$	Gas Volume Used as Fuel	m^3_{gas}
G_{Dsgn}^{Cap}	Greenfield Plant Design Capacity (GPDC)	MTPA
V_{Tr}^{G}	Greenfield Unit Train Capacity	MTPA/Train
K_{HFO}^{HV}	Heating value of heavy fuel oil	J/Tonne
$\dot{V}_{Loss}^{Heel}$	Heel allocation	%
W_{mtce}^{Inact}	Inactive Maintenance Workers	Man
W_{prod}^{Inact}	Inactive Production Personnel	Man
f_{prod}^{WFire}	Inactive Production Personnel Firing Frequency	1/Time
f^{Infl}	Inflation Factor	Dmnl
K_{CF}^{Intrst}	Interest on Capital Policy	Dmnl

Symbol	**Definition**	**Unit**
t_k^{Int}	Intervention Period for E_k	Time
$\dot{M}_{Ordr}^{Out}$	Inventory Arrival Rate	\$/hour
$\ddot{C}_{Hold}^{Inv}$	Inventory Holding Costs	\$/Time
f_{Hold}^{I}	Inventory Holding Costs Fraction	Dmnl
M_{Lot}^{Ordr}	Inventory Lot Size for Order	\$
M_{Hand}^{Inv}	Inventory on hand	\$
$\dot{M}_{Ordr}^{In}$	Inventory Order Rate	\$/hour
$\ddot{C}_{Ord}^{Inv}$	Inventory Ordering Costs	\$/hour
f_{Ord}^{I}	Inventory Ordering Costs Fraction	Dmnl
$\dot{M}_{Hand}^{InvIn}$	Inventory Receiving Rate	\$/hour
f_{Usage}^{InvEff}	Inventory Usage Efficiency Factor	Dmnl
$\dot{M}_{Hand}^{InvOut}$	Inventory Utilisation Rate	\$/hour
f_{BOG}^{Jetty}	Jetty BOG Factor	Dmnl
$\dot{V}_{BOG}^{Jetty}$	Jetty BOG Rate	m^3/Time
K_{BTU}^{Joule}	Joule equivalence of one British Thermal Unit (BTU)	J/BTU
W_{Prod}^{BugCap}	Labour Equivalence From Budget Capability	Man/Time
$\dot{E}_{xLab}$	Labour Expenditure Flow	\$/Time
F_{Lab}	Labour Fund	\$
K_{Lab}^{FF}	Labour Funding Factor	Dmnl
$\dot{F}_{Lab}$	Labour Fund Inflow	\$/Time
K_{Lab}^{IL}	Labour Fund Implementation Level	Dmnl
K_{Lab}^{FLF}	Labour Fund Leakage Factor	Dmnl
E_k	Liquefaction equipment type k	Dmnl
$\dot{V}_{Prep}^{ship}$	LNG Inflow for Shipping	m^3/Time
C^{LNG}	LNG Price	\$/MMBTU
$\dot{V}_{prod}^{LNG}$	LNG Production Rate	m^3/Time
t_{Load}^{ship}	LNG Ship Loading Interval	Time
$\dot{V}_{Load}^{ship}$	LNG Ship Loading Rate	m^3/Time

Symbol	Definition	Unit
V_{LNG}^{ship}	LNG Shipment	m^3_{LNG}
V_{Order}^{ship}	LNG Shipped	m^3
C_{LNG}^{Gas}	LNG Stock Price (Gas)	$/$m^3$gas
V_{SCap}^{LNG}	LNG Storage Capacity	m^3_{LNG}
$V_{FWAi}^{ProdLNG}$	LNG volume produced by the LNGFWA in year i	Year
β_k	Lubrication Cost Fraction for E_k	Dmnl
$MCHE_j$	Main cryogenic heat exchangers of class type j	Dmnl
E_{Mtcek}^{Act}	Maintenance Action for E_k	Dmnl
t_{MAss}^{Strt}	Maintenance Assignment Delay for E_k	Time
t_{MAss}^{Strt*}	Maintenance Assignment Delay Period for E_k	Time
t_{MAss}^{Done}	Maintenance Assignment Completion Delay for E_k	Time
t_{MAss}^{Done*}	Maintenance Assignment Completion Delay Period for E_k	Time
E_{Mtcek}^{Done}	Maintenance Completed for E_k	Dmnl
f_{mtce}^{cost}	Maintenance cost factor	Dmnl
α_k	Maintenance cost fraction for equipment type k	Dmnl
f_{mtce}^{eff}	Maintenance Effectiveness	Dmnl
W_{MFund}^{Cap}	Maintenance Fund capability	Man
$\ddot{C}_{Mtce}^{Lab}$	Maintenance Labour Cost	$/Time
C_{mtce}^{Wage}	Maintenance Labour Wage Rate	$/ManTime
K_{BF}^{MP}	Maintenance Operators Budget Factor	Dmnl
B_{MP}	Maintenance Operators Fund	$
E_k^{WMatAv}	Manpower and Material Availability for E_k	Dmnl
E_{Mtcek}^{Mode}	Maintenance Mode for E_k	Dmnl
E_{Modek}^{WRqst}	Manpower Mode Requested for E_k	Dmnl
W_{mtce}^{gap}	Maintenance Personnel Gap	Man
$\dot{W}_S^{Hire}$	Maintenance Personnel Inflow	Man/Time
W_{Perck}^{Uvail}	Maintenance Personnel Perceived Active and Unavailable for E_k	Man

Symbol	Definition	Unit
W_{Perc}^{Uvail}	Maintenance Personnel Perceived Active and Unavailable in System	Man
$\dot{W}_{S}^{Fire}$	Maintenance Personnel Outflow	Man/Time
f_{mtce}^{Fire}	Maintenance Personnel Outflow Factor	1/Time
E_{Prock}^{Mtce}	Maintenance Process for E_k	Time
t_{mtce}^{DRcrit}	Maintenance Recruitment Delay	Time
$t_{Mtce}^{DRcrit*}$	Maintenance Recruitment Delay Period	Time
W_{Proc}^{Rcrit}	Maintenance Recruitment In Process	Dmnl
$\dot{W}_{S}^{Rcrit}$	Maintenance Recruitment Rate	Man/Time
f_{mtce}^{ReAv}	Maintenance Resource Availability Factor	Dmnl
$\dot{E}_{k}^{Mtce}$	Maintenance Rate for E_k	OpsTime/Time
E_{Dunk}^{WRqst}	Maintenance Workers Request Dun (RD) for E_k	Man
$\dot{E}_{DStrtk}^{WRqst}$	Maintenance Workers Request Signal Start for E_k	Man/Time
$\dot{E}_{DEndk}^{WRqst}$	Maintenance Workers Request Signal End for E_k	Man/Time
S_{mtce}^{WAss}	Maintenance Workforce Assignment Process	Dmnl
J_{jn}^{exptd}	Marginal plant design capacities of base/expansion project j	MTPA
$\ddot{M}_{Matk}^{Usage}$	Material Usage Rate for E_k	$/hour
$f_{Ship}^{MaxLoad}$	Maximum Loading Fraction	Dmnl
W_{MtceS}^{Max}	Maximum Maintenance Workforce No. Allowable	Man
W_{Prod}^{Max}	Maximum Production Workforce No. Allowable	Man
V_{Max}^{ship}	Maximum (Max.) Shipload Capacity	m^3
W_{MtceS}^{Min}	Minimum Maintenance Workforce No. Allowable	Man
W_{Prod}^{Min}	Minimum Production Workforce No. Allowable	Man
C_{Mtce}^{MMC}	Miscellaneous Maintenance Costs (MMC)	$/Time
E_{Mtcek}^{WAv}	MMA for E_k	Dmnl
f_{Mtce}^{MMC}	MMC Factor	%
f_{LNG}^{mmBTU}	MMBTU-LNG Converter	MMBtu/m^3LNG
γ	MT to cubic metre conversion factor	MT/m^3
V_{Aprod}^{NG}	NG Available For Production	m^3_{gas}

Symbol	Definition	Unit
K^{NGC}	Natural Gas (NG) Conversion Factor	Dmnl
$V_{FWAi}^{ProdLNG*}$	NG equivalent of LNG volume produced by the LNGFWA in year i	m^3_{gas}
V_{inproc}^{NG}	NG in Process	m^3_{gas}
$\dot{V}_{inproc}^{NGc}$	NG in Process Conversion Rate	m^3_{gas}/Time
$\dot{V}_{inproc}^{NGw}$	NG in Process Waste Rate	m^3_{gas}/Time
$V_{pl\_max}^{NG}$	NG Plant Capacity	m^3_{gas}
K^{PlC}	NG Plant Capacity Factor	Dmnl
$NCHE_j$	NG pre-cooling heat exchangers of class type j	Dmnl
K^{NGC}	NG purity	Dmnl
$\dot{V}_{stock}^{NG}$	NG Stock Depletion Rate	m^3_{gas}/Time
K_{stock}^{NG}	NG Stock Joint Use Factor	Dmnl
$\dot{V}_{used}^{NG}$	NG Utilisation Rate	m^3_{gas}/Time
V_{Rprod}^{NG}	NG Volume Required for Production	m^3_{gas}
f_{PProg}^{NRcrit}	No Production Workforce Recruitment In Progress	Dmnl
e_{Ncum}^{MAPE}	Non-cumulative MAPE	Dmnl
D_{Feed}^{NG*}	Non-Mtce. Related Feed Gas Delays	Dmnl
N_{Tr}^{B}	Number of Brownfield Trains	Dmnl
N_{Pmk}^{Int}	Number of expected TA maintenance intervention	Dmnl
N_{Tak}^{Int}	Number of expected PM maintenance interventions	Dmnl
N_{Tr}^{G}	Number of Greenfield Trains	Dmnl
W_{Mtcek}^{Rqst}	Number of Maintenance Workers Request for E_k	Man/Time
N_k^{Unit}	Number of Units of E_k	Dmnl
f_{OH}^{O*}	OH cost estimation factor	Dmnl
$\dot{E}_{xOH}$	OH Expenditure Flow	\$/Time
F_{OH}	OH Fund	\$
K_{OH}^{FF}	OH Funding Factor	Dmnl
$\dot{F}_{OH}$	OH Fund Inflow	\$/Time
K_{OH}^{IL}	OH Fund Implementation Level	Dmnl

Symbol	Definition	Unit
K_{OH}^{FLF}	OH Fund Leakage Factor	Dmnl
f_{Yr}^{POP}	Operating Time -Year Conversion Factor	Time/Year
Ω_{EX}^{O}	OPEX Fund Availability Factor	1/Time
$\dot{F}_{EX}^{O}$	OPEX Fund Inflow	$/Time
F_{IL}^{O}	OPEX Fund Implementation Level	Dmnl
$\dot{E}_{xD}^{Less}$	OPEX (Less DP Cost) Rate	$/Time
E_{xD}^{Less}	OPEX (Less DP Cost)	$
E_{xFD}^{Less}	OPEX (Less FG and DP Costs)	$
$\dot{E}_{xFD}^{Less}$	OPEX (Less FG and DP Costs) Rate	$
E_{xFuFD}^{Less}	OPEX (Less FuG, FG and DP Costs)	$
$\dot{E}_{xFuFD}^{Less}$	OPEX (Less FuG, FG and DP Costs) Rate	$
$\dot{E}_{OF}^{Less}$	OPEX [Less overhead (OH), Feed gas [FG] and Depreciation Costs) Rate	$/Time
$\dot{V}_{App}^{Ship}$	Orders Approved for Shipping	m^3
V_{PO}^{ship}	Orders for Shipping	m^3
f_{Policy}^{OrdRct}	Order Receipt Policy on TA Mtce.	Dmnl
$\dot{V}_{OR}^{PO}$	Order Release Rate	m^3/Time
OLE_j	Other liquefaction equipment of class type j	Dmnl
F_{OH}	Overhead/Other Fund	$
C_{BOwn}^{UCap}	Owners Cost Per Unit BPDC	$/MTPA
C_{GOwn}^{UCap}	Owners Cost Per Unit GPDC	$/MTPA
C_{Own}^{Tot}	Owners Total Cost	$
P_{DC}	PDC	MTPA
P_{DC}^{ge}	PDC (Gas Equivalent)	m^3_{gas}
W_{MPerc}^{Avail}	Perceived Personnel Available for Maintenance Service	Man
K^{WC}	Perceived Production Workforce Capability	m^3_{gas}/Man
$\ddot{E}_{xDP}$	Periodic Depreciation Expenses	$
$\dddot{E}_{xDP}$	Periodic Depreciation Expenses Rate	$/Time
$\ddot{R}^{Disc}$	Periodic Discount Rate	%/Time

Symbol	Definition	Unit
$\ddot{C}_{Energy}^{Usage}$	Periodic Energy Cost	\$/Time
$\ddot{E}_{Energy}^{Usage}$	Periodic Energy usage	\$/Time
$\ddot{C}_{FG}^{Usage}$	Periodic Feed Gas Usage Cost	\$/Time
$\dot{C}_{CF}^{Intrst}$	Periodic Interest On Capital Rate	\$/Time
$\ddot{G}_{LNG}$	Periodic LNG Profit	\$/Time
$\ddot{C}_{Trpn}^{LNG}$	Periodic LNG Shipping Cost	\$/Time
$\ddot{C}_{Mtce}$	Periodic Maintenance Cost	\$/Time
$\ddot{M}_{Matk}^{Usage}$	Periodic Material usage rate for E_k	\$/Month
$\hat{B}_{EX}^{O}$	Periodic OPEX Budget	\$
Ψ_{EX}^{O}	Periodic OPEX Budgeting Factor	Dmnl
$\hat{F}_{EX}^{O}$	Periodic OPEX Fund	\$
$\ddot{E}_{xFGDP}^{Less}$	Periodic OPEX (Less [FG] and DP Cost)	\$/Time
C_{OH}^{O}	Periodic OH Cost	\$/Time
P_{PC}	Periodic Plant Capacity (LNG)	m^3/Time
P_{PC}^{ge}	Periodic Plant Capacity (Gas Equivalent)	m^3/Time
$\ddot{C}_{Tak}^{IntCst}$	Periodic TA Costs per Intervention for E_k	\$/hour
$\ddot{C}_{Tak}^{IntEx}$	Periodic TA Expense per Intervention for E_k	\$/Time
$\ddot{G}_{Rev}$	Periodic Revenue	\$/Time
$\ddot{V}_{delvd}^{Ship}$	Periodic Shipment Delivered	m^3_{LNG}/Time
$\dot{t}_{k}^{Up}$	Periodic Uptime for E_k	OpsTime /Time
$\dot{W}_{Prod}^{Wage}$	Periodic workforce wages	\$/Time
W_{MReg}^{gap}	Personnel Gap (Regular Maintenance)	Man
W_{MNReg}^{gap}	Personnel Gap (Non-regular Maintenance)	Man
E_{k}^{WRqst}	Personnel Request for E_k	Dmnl
W_{Cm}^{Rqrd}	Personnel Required for CM	Man
W_{Mtce}^{Rqrd}	Personnel Required for Maintenance	Man
W_{Pm}^{Rqrd}	Personnel Required for PM Maintenance	Man
W_{TaM}^{Rqrd}	Personnel Recruitment for TA Maintenance	Man

Symbol	Definition	Unit
W_S^{Fire}	Personnel for Retrenchment	Man
$PPNG_j$	Piping of class type j	Dmnl
$E_{Mtcek}^{P\_Up}$	Planned/ Unplanned Maintenance for E_k	Dmnl
A_{Plt^*}	Plant availability in operation time t^*	Dmnl
$E_{Syst^*}^{ConvEff}$	Plant NG conversion effectiveness in operation time t^*	Dmnl
$K_{OCt^*}^{P}$	Plant operating capacity factor in operation time t^*	Dmnl
K_{OBN}^{P}	Plant Operation Bottleneck Factor	Dmnl
t^*	Plant Operating Period	Time
t_{pw}	Plant Operation Window	Time
$\dot{t}_{pw}$	Plant Operation Window Wind-Up Rate	OpsTime/Time
K^{PrC}	Plant Productivity	Dmnl
C_{slvg}	Plant Salvage value	$
t_{pw}^{*}	Plant Unit Operation Window	Time
P_L	Plant Useful Life	Time
E_{Mtcek}^{PmAct}	PM Action for E_k	Dmnl
E_{Signk}^{PmAct}	PM Action Signal for E_k	Dmnl
f_{Ek}^{TecPM}	PM Efficiency Factor for E_k	Time
t_k^{PmI}	PM Intervention Period for E_k	Time
f_{Ek}^{LogPM}	PM Logistics Factor for E_k	Time
$\ddot{C}_{MCPm}^{Exp}$	PM Maintenance Expense Rate	$/Time
E_{PMk}^{PreReq}	PM Personnel Pre-Request for E_k	Dmnl
E_{Pm}^{WRqst}	PM Personnel Request	Dmnl
t_{PmCdnk}^{WRec}	PM Recruitment Countdown for E_k	Time
f_{PMk}^{Req}	PM request Factor	Dmnl
t_{PMk}^{ReqWin}	PM Request Window for E_k	Time
W_{Pm}^{Press}	PM Workforce Pressure	Man
t_{PmCdn}^{WRec}	PM Workforce Recruitment Countdown	Time
C_{Ship}^{Port}	Port charges	$/Trip

Symbol	Definition	Unit
R_k^{Power}	Power rating for E_k	MW
V^{PPLR}	PPLR	m^3
V^{PPLRge}	PPLR (Gas Equivalent)	m^3_{gas}
D_{Feed}^{NG**}	PPNG Maintenance Action	Dmnl
$C_{PrevAct}^{OPEX}$	Previous activity-based OPEX Rate	$/Time
C_{EXi}^{Prev}	Previous periodic OPEX for OPEX component i	$
$K_{t^*}^{Prc}$	Process capability factor value in operation time t^*	Dmnl
V_{prod}^{LNG}	Produced LNG In Storage	m^3
$\ddot{C}_{Prod}^{Lab}$	Production Labour Cost	$/Time
W_{Prod}^{Wage}	Production Labour Wage Rate	$/ManTime
B_{PP}	Production Operators Fund	$
θ_{Prod}	Production Operator Productivity	Dmnl
$\dot{V}_{order}^{prod}$	Production Order Accumulation Rate	m^3/Time
K_F^{po}	Production Order Frequency	1/Time
t^{po}	Production Order Interval	Time
$\dot{V}_{order}^{prod}$	Production Order Rate	m^3/Time
$\dot{W}_{prod}^{Fire}$	Production Personnel Firing Rate	Man/Time
t_{Prod}^{DRcrit}	Production Recruitment Delay	Time
$t_{Prod}^{DRcrit*}$	Production Recruitment Delay Period	Time
f_{Prod}^{ResAv}	Production Resource Availability Factor	Dmnl
$\dot{V}_{start}^{LNG}$	Production Start Rate	m^3_{gas}/Time
W_{prod}^{Rcrit}	Production Workforce for Recruitment	Man
$\dot{W}_{prod}^{Rcrit}$	Production Workforce Recruitment Rate	Man/Time
W_{PRqst}^{Rcrit}	Production Workforce Recruitment Request	Man/Time
f_{PProg}^{Rcrit}	Production Workforce Recruitment In Progress	Dmnl
G_{LNG}^{Unit}	Profit per Unit LNG	$
C_{kbase}^{UP}	Purchase cost of a unit of E_k in base year t_{base}	$
C_{kRef}^{UP}	Purchase cost of a unit of E_k in reference year t_{Ref}	$

Symbol	Definition	Unit
$P_{Ek}^{\Phi r}$	Random Failure Probability for E_k	Dmnl
$f_{Ek}^{\Phi r}$	Random Failure Probability Parameter for E_k	Dmnl
f_{Prod}^{RcrRel}	Recruited Production Personnel Release Frequency	1/Time
$\dot{W}_{prod}^{RcrRel}$	Recruited Production Personnel Release Rate	Man/Time
M_{Point}^{Rordr}	Reorder Point	$
W_{Prod}^{BLog}	Required Production Workforce Backlog	Man/Time
V_{Res}^{prod}	Residual LNG Desired from Production	m^3
V_{Res}^{prodGe}	Residual LNG Desired from Production (GE)	m^3_{gas}
$\dot{E}_k^{Rsrt}$	Restart Rate for E_k	OpsTime/Time
P_{ROI}	Return On Investment	%
$\dot{G}_{Rev}$	Revenue Inflow	$/Time
M_{Safe}^{Inv}	Safety Inventory Stock	$
$C_{Tont^*}^{LNG}$	Sale price per Tonne of HFO	$/Tonne
$C_{Tont^*}^{LNG}$	Sale price per Tonne of LNG	$/Tonne
f_{Site}^{Cmplx}	Site Complexity Factor	Dmnl
f_{Site}^{Loc}	Site Location Factor	Dmnl
C_{Ship}^{Brkg}	Ship agency and brokerage charges	$/Trip
C_{Ship}^{Chrt}	Ship charter rate	$/Trip
C_{Ship}^{Fuel}	Ship fueling cost	$/Trip
C_{Ship}^{Insr}	Ship insurance cost	$/Trip
$V_{Load}^{MaxShip}$	Ship maximum LNG varying capacity	m^3
$\dot{V}_{delvd}^{Ship}$	Shipment delivery rate	m^3/Time
D_{Prep}^{ship}	Shipment Preparation Delay	Time
$\dot{E}_{xTrpn}$	Shipping Expenditure Flow	$/Time
K_{Trpn}^{FF}	Shipping Funding Factor	Dmnl
F_{Trpn}	Shipping Fund	$
$\dot{F}_{Trpn}$	Shipping Fund Inflow	$/Time
K_{Trpn}^{IL}	Shipping Fund Implementation Level (FIL)	Dmnl

Symbol	Definition	Unit
K_{Trpn}^{FLF}	Shipping Fund Leakage Factor (FLF)	Dmnl
$\dot{V}_{LNG}^{shipped}$	Shipping Rate	m^3/Time
$\dot{V}_{LNGBTU}^{shipped}$	Shipping Rate (MMBTU)	MMBTU/Time
E_S^{SpAv}	Spare availability	Dmnl
E_{CmPm}^{SpAv}	Spare Availability for CM/PM	1/hour
E_{Ta}^{SpAv}	Spare Availability for TA Maintenance	1/hour
A_S	System Availability	Dmnl
A_S^S	System Availability Status	Dmnl
t_S^I	System CM Intervention Time	Time
$\dot{t}_S^d$	System Downtime Accumulation Rate	OpsTime/Time
L_s	System Expected Life	Time
Φ_S	System Failure	Dmnl
C_S^{Use}	System Material Usage Rate	$/hour
$\dot{E}_{Ta}^{Rsrt}$	System Restart After TA Maintenance Done	Dmnl
$\dot{t}_S^U$	System Usage Rate	OpsTime/Time
E_S^{Uf}	System Unplanned Failure (UF) event	Dmnl
C_{Ta}^{PerInt}	TA Costs per Intervention	$
C_{Tak}^{PerInt}	TA Costs per Intervention for E_k	$
f_{Ek}^{TecTA}	TA Efficiency for E_k	Time
t_k^{TaI}	TA Intervention Period for E_k	Time
t_{Ta}^{InvDel}	TA Inventory Delay (ID) Period	Time
f_{Ek}^{LogTA}	TA Logistics Factor for E_k	Time
E_{Mtcek}^{TaAct}	TA Maintenance Action for E_k	Dmnl
E_{Sign}^{TaAct}	TA Maintenance Action Signal	Dmnl
f_{Ta}^{mtce}	TA Maintenance Cost Fraction	Dmnl
t_{Donek}^{Ta}	TA Maintenance Done for E_k	Dmnl
t_{Tak}^{IntDur}	TA Maintenance Duration for E_k	Time
$\ddot{C}_{MTak}^{Exp}$	TA Maintenance Expense Rate for E_k	$/Time

Symbol	Definition	Unit
$\ddot{C}_{MTa}^{Exp}$	TA Maintenance Expense Rate	$/Time
f_{TaFrq}^{mtce}	TA Maintenance Frequency	Dmnl
t_{Initk}^{TA}	TA Maintenance Initiation	OpsTime/Time
t_{Mtce}^{Ta}	TA Maintenance Interval	Time
t_{Tak}^{Wrqrd}	TA Maintenance Man-hour Required for E_k	Time
M_{MTa}^{Ordr}	TA Maintenance Material Order Units	$
$E_{TAk}^{\boldsymbol{WMatAv}}$	TA MMA for E_k	Dmnl
t_{mtce}^{TA}	TA Maintenance Time	Time
W_{Ta}^{Press}	TA Maintenance Workforce Pressure	Man
E_{Tak}^{Rqst}	TA Maintenance workers Request for E_k	Dmnl
W_{Tak}^{Rqrd}	TA Maintenance Workforce Required for E_k	Man
$\ddot{C}_{Ta}^{PrdInt}$	TA Periodic Costs per Intervention	$/hour
$\dot{W}_{Tak}^{Met}$	TA Periodic Maintenance Workforce Requirement Met for E_k	Man/Time
$\dot{W}_{Tak}^{Rqrd}$	TA Periodic Maintenance Workforce Required for E_k	Man/Time
$E_{Tak}^{MetRqst}$	TA Periodic Personnel Request Met for E_k	Dmnl
E_{Tak}^{PreReq}	TA Personnel Pre-Request for E_k	Dmnl
E_{Tak}^{WRqst}	TA Personnel Request for E_k	Dmnl
E_{Ta}^{WRqst}	TA Personnel Request	Dmnl
C_{Ta}^{TotInt}	TA Total Costs per	$
C_{xTa}^{MTot}	TA Total Periodic Maintenance Expense per	$/Month
t_{TaCdn}^{WRec}	TA Workforce Recruitment Countdown	Time
C_M^T	Total Bulk Materials Cost	$
$\hat{F}_{EX}^{TC}$	Total CAPEX Fund	$
W_{CmTot}^{Rqst}	Total CM Man Power Request	Man
C_c^T	Total Construction Cost	$
D^T	Total Depreciation Expenses	$
$\dot{G}_{LNG}^{Disc}$	Total Discounted Profit Flow In	$/Time
G_{LNG}^{Disc}	Total Discounted Profit	$

Symbol	Definition	Unit
E_{xTrpn}	Total Shipping Expenses	$
t_S^U	Total System Usage	Time
W_{Tarqd}^{Tot}	Total TA Man Power Requirement	Man
V_{inproc}^{w}	Total Waste (LNG Equivalent)	m^3
V_{inproc}^{wge}	Total Waste NG from Process	m^3_{gas}
f_{BOG}^{Trnst}	Transit BOG Fraction	%/Time
$\dot{V}_{BOG}^{Trnst}$	Transit BOG Rate	m^3/Time
E_A^{TRPN}	Transportation Equipment (TRPN) Uptime	Time
t^{ToPm}	TTPM	Time
t_k^{ToPm}	TTPM for E_k	Time
t_{TTPmk}^{Thr}	TTPM Threshold for E_k	Time
t_k^{ToTa}	TTTA Maintenance	Time
t_{TTTak}^{Thr}	TTTA Threshold for E_k	Time
E_{Mtce}^{TaAct}	Turnaround Maintenance Action	Time
$C_{Prod}^{UnitLNG}$	Unit LNG Production Cost	$/MMBTU
E_k^{Uf}	Unplanned Failure (UF) event for E_k	Dmnl
E_{Ufk}^{WRqst}	Unplanned Failure Personnel Request for E_k	Dmnl
E_{Signk}^{Uf}	Unplanned Failure Signal for E_k	Dmnl
E_{Mtcek}^{UAct}	Unplanned Maintenance Action for E_k	Dmnl
f_{Upper}^{TLead}	Upper Lead Time Tolerance	Dmnl
M_{MatTa}^{Use}	Used Material (TA)	$
M_{MatTa}^{UseIn}	Used Material (TA) In Flow	$/hour
M_{MatTa}^{UseOut}	Used Material (TA) OutFlow	$/hour
β_{Ek}	Weibull Shape parameter for E_k	Dmnl
η_{Ek}	Weibull Scale parameter for E_k	Time
W_{Prod}^{Est}	Workforce Estimated for Production	Man
W_S^{Rcrit}	Workforce for Maintenance Recruitment	Man
W_{Prod}^{Perc}	Workforce Perceived for Production	Man

Symbol	Definition	Unit
W_{zPemnt}^{Wage}	Workforce wage rate for permanent staff	\$/Time
W_{zCtrct}^{Wage}	Workforce wage for contract staff	\$/Time
f_{zct-pt}^{Wage}	Workforce wage rate fraction for W_{zCtrct}^{Wage} and W_{zPemnt}^{Wage}	Dmnl

CHAPTER ONE

INTRODUCTION

1.1 Background of the study

A Product cost estimation model is an instrument for predicting the unit cost of a product to be produced in some future period under specified conditions. A lot of budgetary decisions before actual production; planning; and profitability analysis are based on such costs (Adegbuyi & Asapo, 2010; Dugaal, 2022). Hence, the process of developing a model for estimating product cost is very important as a model that overestimates may introduce some avoidable operational cost penalties. The same is true for an underestimate. Consequently, it is desirable that accurate cost estimates are made right from business conception.

The severity of incurred penalty costs due to inaccurate estimates may vary from product to product depending on the capital intensity of the business. The more capital intensive, the higher such penalty may be. One such capital-intensive product in Nigeria is Liquefied Natural Gas (LNG). Nigeria, endowed with great natural gas deposits, has been flaring the gas for well over two decades (Ejiogu, 2013; Adekomaya *et al.*, 2016; Elehinafe *et al.*, 2022). In recent times several investors have indicated business interests in owning LNG in Nigeria.

This implies that in the future the economy of Nigeria may well depend on how effectively and efficiently the LNG business is transacted. Being an internationally-traded commodity with prices strongly influenced by marketplace-perceived supply and demand as well as other macro-economic realities, Nigeria may achieve a competitive advantage only if major LNG projects are designed and run to attain the lowest unit cost (Andeobu *et al.*, 2005; Andeobua *et al.*, 2010; Odumugbo, 2010; Vasili *et al.*, 2011).

This calls for the use of sophisticated product cost estimation models right at the business conception stage. One such model which may be a useful decision-support instrument for selecting appropriate LNG plant location, design, procurement strategy, production management, etc. for long term plant reliability and customer services is life cycle cost (LCC) estimation. Life cycle costing is an all-product-lifespan-activities approach to costing. Developing LNG life cycle cost estimation model with desired accuracy is, however, an intractable process (Aurich *et al.*, 2009; Farsi *et al.*, 2020). It is made complex by the nature of the LNG operation structure which has many interrelated business processes, long product life span whose activities are usually impacted by unpredictable risky events.

Historically, such cost estimation models are usually mathematical, statistical and/or simulated (Tamura *et al.*, 2001; Sievanen and Tornberg, 2002; Tagliaferri *et al.*, 2017). As earlier inferred, model accuracy is the main criterion for selecting suitable models. However, model accuracy is a concept that depends on a large number of factors ranging from data attributes to variety of product-related man-machine activities. Perhaps, the complexity of the concept and its implication to model development may be better appreciated when some of these factors are outlined. Derived from the LNG value chain, the following are some of such factors:

(i) Business conception activities including market survey;
(ii) Business partnership transaction activities;
(iii) LNG Plant design and construction activities;
(iv) Personnel acquisition activities;
(v) Material supply activities;
(vi) LNG Production activities;
(vii) LNG management activities;
(viii) LNG Facilities maintenance activities;
(ix) LNG Facilities expansion activities;
(x) Product storage and distribution activities; and
(xi) Product retirement activities.

Other factors are:

(xii) Data integrity; and
(xiii) Data availability.

Still, others that are time-related are:

(xiv) Product life span;

(xv) Environmental Changes;

(xvi) Uncertainty of future events; and

(xvii) Interaction between factors.

In addition, the type of Mathematical/statistical/simulation model applied may affect accuracy (AlArjani *et al.*, 2022; Li, 2022; Robinson, 2022).

It may be noted that the accuracy of a model will depend largely on the extent to which it can capture information on all the aforementioned factors. The more factors incorporated in a model estimating structure, the higher its likelihood to increase its degree of accuracy and vice versa. Thus, it is desirable for a model developer to capture as many relevant factors as possible in a single model.

Unfortunately, most mathematical, statistical, simulation and even knowledge-based models have limitations. Hence, the chance of a single model accounting for all possible factors is slim. Many static and deterministic mathematical models account mostly for data captured on the activities but fail to reflect time-based changes, uncertainty, feedback information, delays and factor interactions (Glerum, 2014; Kowgier, 2022). Statistical models are, however, able to cater to the activities and uncertainty but weak in accommodating time-based changes, incorporation of timely feedback data and interactions (Xie, 2011; Henley *et al.*, 2020). Simulation models which incorporate mathematical and statistical functions have been found to accommodate more factors including time-phased activities, environmental changes, uncertainty and some degree of factor interactions. Discrete event simulation models are however weak in dealing with feedback data and factor interactions (Caro & Möller, 2016; Collins *et al.*, 2023). Continuous event simulation models have been more robust in accommodating a wider spectrum of factors and operating situations.

One approach which easily combines various types of mathematical and statistical functions, computer logic and usually gives birth to continuous event simulation models is System Dynamics (Azar, 2012; Jovanoski *et al.*, 2012; Al-Hawari *et al.*, 2022). Thus, it is intuitively appealing to apply systems dynamics modeling principles to model all the LNG serially related activities, parallel operating facilities, life cycle events and the associated environmental time-based changes as operating cost contributors. This work is an attempt to develop an LNG life cycle costing model using a systems dynamics approach.

1.2 Statement of the Problem

As earlier mentioned, previous LNG cost estimates were made as projections of historical annual operating cost data using either time series analysis, regression analysis, or statistics combined with engineering economic tools (Al-Saadoon & Nsa, 2009; Hönig *et al.*, 2019; Shim & Cho, 2019; Meira *et al.*, 2022). The implicit assumption is that previous LNG operations are satisfactory therefore advantageously replicable for the future. This, of course, may not hold given the increasing influences of uncertainties and global competition with time.

Future operating conditions may require new adaptive operating and management strategies for improvements and survival. For example, the use of timely operating feedback data for effective LNG plant control decisions (Angelsen *et al.*, 2006; Michelsen *et al.*, 2010; Basak *et al.*, 2019). This is a feature lacking in some of the reported approaches. Besides, product unit cost behavior may display transient and convergence characteristics with time. It is when the cash flow rate, wellhead gas supply rate, manpower supply rate, steady plant supply rate, and energy supply rate are balanced that unit cost may converge to a minimum value. Hence, these resource flow rates are desirable operating parameters. They give rise not only to minimum unit cost but also to maximum LNG plant production flow rate. Of course, a process capable of determining these values may also require knowledge of causality-based interrelationships between LNG production factors. It thus appears obvious that, in the process of accurate LNG cost estimation, the following issues require attention:

(i) Establishment of the causality-based relationship between a set of LNG process governing factors;
(ii) Development of a decision-support model for the timely provision of LNG operating data feedback for automatic process control; and
(iii) Determination of desirable LNG operating resource flow rates.

These issues are the problems addressed in this thesis.

1.3 Aim and Objectives of Study

This study aims to develop a continuous time-based life cycle cost estimation model for LNG plants for effective investment decision.

To achieve this aim the specific objectives of the study are to:

1. Identify all LNG life cycle cost-related variables and parameters;
2. Determine the interrelationships among the identified variables and parameters;
3. Develop an LNG lifecycle-based costing model using System Dynamics tools;
4. Examine LNG system behavior under different operating environments.

1.4 Justification of the Study

Since the LCC analysis for LNG production plants is complex and involves many interacting and feedback cost factors, a systematic approach at its estimation possesses the capability to recognise both the effects of cost factors on one another and on the complete system towards the attainment of the goal of the project owner.

In addition, the system based approach at assessing all cost components incurred throughout an entire project life cycle in LNG investment decisions will aid in attenuating the LNG plant failures caused by lack of adequate information on the cost of materials, operations, maintenance and product delivery.

The outcomes of this study will provide an understanding of the dynamics of LNG projects and in effect provide information necessary for risk management and project planning and decision making for LNG plant life cycles. In addition, it will improve management's awareness of total LNG project costs and viabilities and allow stakeholders to evaluate competing options in design/procurement. This will be of the utmost benefit to investors with respect to access funds for investment, FIDs and procedure formulation with project beneficiaries. Overall, this study, will improve growth in the LNG sector, lower project failure and reduce wastes.

1.5 Scope of the Study

This study is limited to the application of System Dynamics tools in the development of LNG operating cost mathematical function and decision-support simulation model with the incorporation of all operating resource supply and production rates. It will also include plant maintenance and LNG operating segment interactions and data feedback mechanisms. Although, this research focused on the formulation and analysis of life cycle models for the liquefied natural gas system in the midstream and downstream sectors. However, it also evaluated some upstream sector activities that showed interrelationship with the midstream and downstream sectors. Model formulation and analysis were achieved using VENSIM PLE with activity-based sector approach costing principles. The data used in model validation and implementation were limited to a single firm's operations records and were obtained from primary and secondary sources. The evaluation and validation of the models were limited to the use of Mean Average Error (MAE) and the Mean Average Percentage Error (MAPE) Economic analysis was achieved using the Net Present Value (NPV), Payback Period and profitability index models. The study did not consider the environmental management cost component of LNG operations.

1.6 Definition/Explanation of Terms

The following are some of the technical terms applied in this report:

i. Discount Rate- In line with ISO/DIS 15686-5 (2006) recommendations it is the factor reflecting the time value of money that is used to convert cash flows occurring at different times to a common time.

ii. Life Cycle - The defined service life cycle of the product, is the period between the inception and completion of the functional need (cradle to grave), or only for life cycle assessment of the period of interest in a system, component, or product.

iii. Life Cycle Costing- A tool and technique which enables comparative cost assessments to be made over a specified period, taking into account all relevant economic factors both in terms of initial capital costs and future operational and asset replacement costs, through to end-of-life, or end-of-interest in the asset – also taking into account any other non-construction costs and income, defined as in scope.

iv. Availability -The ability of an item to be in a state to perform a required function under given conditions at a given instant of time or over a given time interval, assuming that the required external resources are provided.

v. Reliability -The probability that an item can perform a required function under given conditions for a given time interval.

vi. Maintainability -The probability that a given active maintenance action for an item under given conditions of use can be carried out within a stated time interval when the maintenance is performed under stated conditions and using stated procedures and resources.

vii. Corrective maintenance -The maintenance carried out after fault recognition and intended to put an item into a state in which it can perform a required function.

viii. Preventive maintenance -The maintenance carried out at predetermined intervals or according to prescribed criteria and intended to reduce the probability of failure or the degradation of the functioning of an item.

ix. Net Present Value -Net Present Value is the sum of the discounted future cash flows.

x. Nominal Discount Rate- Rate used to relate present and future money values in comparable terms taking into account the general inflation/deflation rate.

xi. Period of Analysis- Length of time over which an LCC assessment is analysed.

xii. Whole Life Cost -The systematic economic consideration of all agreed significant costs and benefits associated with the acquisition and ownership of a product which is anticipated for analysis expressed in monetary value.

xiii. Causal loop Diagram - this diagram shows the interaction of two system elements with one another. It may also be referred to as influence diagrams.

xiv. Stocks - These are the accumulators of the system. They are the nouns in the language of system dynamics. They represent the state of a system at any specific time. They can be tangible things like money, planes, and parts. They can also be intangibles like happiness, anger, burnout, and productivity.

xv. Flows - these are the regulators of the stocks. They are the verbs of the language of system dynamics. They regulate how much the stocks are filled up or depleted. They are always defined as a rate.

xvi. Flow Diagram - This is a diagram that shows how variables transit through a system. It graphically depicts the state of a system and the factors that cause it to change.

1.7 Outline of Succeeding Chapters

The remaining portion of the report was organised into four chapters:

Chapter two reviewed existing literature on product costing; Chapter three presented the methodology of the study while Chapter four addressed data collection, analysis and discussion of the results. Finally, the summary, conclusion and recommendation for further study were presented in Chapter Five.

CHAPTER TWO

LITERATURE REVIEW

2.1 Liquefied Natural Gas Value Chain

A typical LNG value chain consists of different activities that ensure the production and processing of natural gas to LNG and the subsequent distribution of the resulting product to the consumer (Mannan, 2012). According to the US Department of Energy (2020) the LNG value chain essentially consists of the following activities: production and processing, and the subsequent conversion of NG to LNG. These are followed by, LNG transportation to and regasification by the consumer. Another form of classification is based on the industry segment perspective. That is, LNG industry activities has three segments namely, the upstream, midstream, and downstream sectors (Inkpen and Moffett, 2011; Petro Online, 2014; Harraz, 2016). The activities are briefly explained in terms of the segments in which they are classified.

2.1.1 Upstream activities

LNG industry upstream activities involve the exploration and production of NG. In this phase of the LNG value chain, NG is extracted from sub-surface reservoirs such as offshore and onshore NG wells, shale rocks, crude oil wells and coal beds (MetGroup, 2021; US Energy Information Administration [EIA], 2022). This is usually achieved by the use of sophisticated drilling equipment which are used to tap into the sources and draw oil and natural gas to the surface.

It has been reported that this sector of the value chain is dominated by partnerships among national oil companies with international oil companies (USDA and USEA, 2016; Olujobi, 2020). This is even more so in countries where NG reserves are far from major markets due to large capital requirements and the need for experienced operators.

The key to success of the LNG business with respect to this stage of the value chain, is detailed and thorough strategic asset planning. Asset plans and strategies enable the identification of the long-term requirements to match production levels at all phases of the project with planned supply to local and export markets (USDA and USEA, 2016). This stage also guides and directs the creation of investment and maintenance plans that are essential for resource allocations that are consistent with achieving desired outcomes. Agreements must the LNG suppliers and buyers must also be in place at this stage.

2.1.2 Midstream activities

This category of activities is that of Natural gas transportation and processing. It involves the transportation of the produced gas and subsequent processing for purification purposes. The produced NG from the upstream phase which is referred to as 'feed gas' is transported by a process called 'small gathering' to processing facilities. The mode of transportation could be via pipelines, tankers, trains, or barges (Petro Online, 2014). At the processing facilities, impurities such as water, water vapour, hydrogen sulphide, Carbon (iv) oxide, mercury, and Nitrogen are removed. In addition, unwanted NG liquids such as ethane, propane and butane are scrubbed and may be collected, shipped and sold separately. These are done to ensure that the resulting feed gas meets specific global requirements on product quality, environmental regulations and emission limits (Mokhatab *et al.*, 2014).

2.1.3 Downstream activities

The downstream segment comprises all activities directed at ensuring that the processed natural gas is effectively and efficiently delivered to the consumer. It involves all activities that are related to conversion to LNG, the transportation of the liquefied product to expected destinations and subsequent regasification for energy generation and industrial usage. This study is concerned with LNG conversion and transportation and as such these activities are further discussed.

2.1.3.1 Natural gas conversion

Liquefaction is the process of Natural gas conversion through heat removal over a wide temperature range (Khan *et al.*, 2017). For any liquefaction process to be successful, a functional liquefaction plant must be available. Liquefaction plants are onshore and off-shore facilities (Floating LNG [FLNG]) from which NG conversion is achieved (Gallagher, 2018; Songhurst, 2018). Liquefaction takes place by passing the NG through cooling heat exchangers with exposure to compressed hydrocarbon-nitrogen refrigerant. The resulting

LNG is pumped to an insulated storage tank where it remains until it can be loaded onto a tanker for shipping.

2.1.3.2 Liquefaction process selection and plant construction consideration

As a result of the scale of LNG operation coupled with the corresponding energy requirements and process efficiency, all factors that affect liquefaction operations must be carefully considered. Also, Castillo *et al.* (2010) identified nine factors and sixteen sub-factors that can impact the decision to choose an LPT. These factors are mostly related to economics, constructability, and process maturity. Other factors are technical, environmental [carbon (iv)] oxide emission, feed gas composition, process operability and maintainability, commercial flexibility of licensor and domestic preferences. Table 2.1 shows a breakdown of these factors in terms of the identified sub-factors.

Khan *et al*. (2017) further summarise these factors into strictly technical and economic factors with the technical factors being process type, efficiency, reliability, site conditions and environmental impact. The economic factors were identified as lifecycle costs, upfront capital expenditure and operating costs over the expected plant lifetime, heating/cooling medium, compressor/drivers and ancillary equipment. These factors are further discussed using the Khan *et al*. (2017) classification.

2.1.4 Technical factors affecting natural gas liquefaction

The technical factors that affect NG liquefaction include liquefaction process types (liquefaction trains, liquefaction process technologies), plant efficiency, reliability, and site conditions.

2.1.4.1 Liquefaction trains

A typical liquefaction plant consists of standalone processing units called trains. A plant can be made up of a single train or multiple trains operating in parallel (USDA and USEA, 2016).

A typical LNG train is made up of a set of equipment capable of converting NG into LNG. Some of such equipment include Gas turbines, heat exchangers, vaporisers, extractors, storage tanks, scrubbers, filters and chillers.

Table 2.1: Factors considered in liquefaction process technology

SN	Factor	Sub factor
1	Economics	• Investment cost • Operating Cost
2	Constructability	• Expandability plant • Train area requirement
3	Project maturity	• Years of operation • Maximum capacity per train set • Installed capacity • Maximum capacity per train planned
4	Technical	• Cryogenic heat exchanger type • Compressor/actuator type • Specific power • Refrigerant type(s) • Number of refrigeration cycles • Availability of refrigerant
5	Environmental (carbon (iv) oxide emission,	--
6	Feed gas composition,	--
7	Process operability and maintainability	--
8	Commercial flexibility of licensor	--
9	Domestic preferences	• National content • Sustainable development

Source: (Castillo *et al.*, 2010)

An LNG train is usually described in terms of its converted LNG capacity. Currently, LNG nominal train capacities exist within the range of 0.5 – 8 Million Tonnes Per Annum (MTPA) (Eaton *et al.*, 2004; Caswell, 2019), about 5 MPTA on average.

2.1.4.2 Liquefaction process technologies

Liquefaction of NG is an energy-intensive activity and as such the selection of the type of process to execute the activity is significantly important (Hung *et al.*, 2022). Liquefaction process technologies refer to various methods that are deployed in achieving LNG liquefaction. Khan *et al.* (2017) identified eight basis for classifying liquefaction process technologies namely:

1. The scale of LNG produced
2. Number of refrigeration cycles used
3. Refrigerant type: mixed or pure
4. Refrigerant cycle arrangement cascade or in parallel.
5. Expander/No expander involved
6. Flammable refrigerant or non-flammable refrigerant employed
7. Precooling /without precooling
8. Heat exchanger employed: spiral-wound type exchanger/plate frame exchanger

For example, in terms of their size and function, NG liquefaction was grouped into large baseload, mid-scale, peak shaving, and small-scale plants (Mokhatab and Messersmith, 2018) [Table 2.2]. Baseload plants, typically consist of one or multiple trains and supply natural gas as LNG to consumer nations by ocean transport.

Barclay and Shukri (2000) classified liquefaction process technologies based on the number of liquefaction cycles or loops. Another classification by Inkpen and Moffett (2011) grouped liquefaction process technologies into two primary groups namely the multi-component refrigerant and the Phillips cascade process. In another case, based on the refrigeration cycle cascade classification, the classical cascade, modified cascade cycle and pre-cooled mixed refrigerant cycle were identified (Nasr and Connor, 2014).

However, (Khan *et al.*, 2017) classified liquefaction processes into four major groups based on their generic process technologies. These are expander-type, mixed refrigerant-type, cascade-based, and hybrid-type process technologies.

Table 2.2: LNG plant classification by production scale and usage

LNG plant type	Typical production capacity per train (MTPA)	Application	Types of liquefaction process technology deployed
Small scale	0.01	Emergency fuel backup, vehicle fuel re-liquefying ship boil-off gas	• Gas Expansion • Nitrogen Expansion • Single Mixed Refrigerant
Peak shaving	Up to 0.1	Provision of extra capacity during peak demand periods	
Mid-scale (Mini/Micro)	0.3-1.5	Domestic consumption, transport by road or rail	• Dual Mixed Refrigerant • C3MR • Cascade ProcessTechnologies • Hybrid Process Technologies
Baseload	≥ 3	Overseas export by ship	

Source: Adapted from (Tractebel Engineering, 2015; Mokhatab and Messersmith, 2018)

A discussion of the different process technology types based on the modified form of the Khan *et al.* (2017) classification is subsequently discussed.

A. Expander-type liquefaction process technology

Essentially, the expander-type liquefaction process technology (EtLPT) works by the cryogenic process of dropping the temperature of gas streams to around –120°F. It involves the use of external refrigerants for cooling the NG and turbo-expansion equipment to rapidly expand the chilled gases leading to significant drops in NG temperature (Khan and Islam, 2007). This leads to hydrocarbon-based natural gas liquids condensing out of the feed gas stream, maintaining methane in gaseous form. This process has the capability of recovering up to 98% of the ethane (JASE-W, 2022). Examples of these types of process technology include the N_2, N_2-CO_2, Dual N2 Expander, and AP-X processes.

EtLPT has some advantages which include

(1) Reduction in hydrocarbon flaring
(2) Affords some level of simplicity due to ease of operation
(3) Eliminates refrigeration distribution in heat exchangers as refrigerant remains in the gaseous form throughout the liquefaction process
(4) Affords the capability for shutdown and startup of the process
(5) May be relatively cheaper than the other LPTs as heat exchanger size requirements are lower.

However, EtLPT is only suitable for small-scale LNG production

B. Refrigerant-mix-based liquefaction process technology

The refrigerant-mix-based liquefaction process technology (RMLPT) is concerned with the type of refrigerant mixes that are utilised for NG liquefaction. Essentially, multiple refrigerants are used for the cooling process. However, these refrigerants may be used as independently in the same process as in the case of the classical cascade liquefaction process (Nasr and Connor, 2014) or as a mix of refrigerants in the case of the single mix refrigerant (SMR) process or the multicomponent mix refrigeration [MCMR] (Kohler *et al.*, 2014; Nasr and Connor, 2014; Khan *et al.*, 2017).

The classical cascade cycle makes use of three separate refrigerants, propane, ethylene and methane in three different refrigeration cycles where heat rejection is achieved in a cascading pattern from a lower temperature cycle to a warmer cycle. Regarding the SMR, a single refrigerant stream is deployed using a mix of hydrocarbon-based refrigerants (derived from the NG) for cooling. Liquefaction is attained from temperature drops experienced by the NG as a result of a series of heat exchanges from refrigerant and NG caused the passage of the fluids through different expanders and heat exchangers. The MCMR utilises a process that is a combination of the cascade and the SMR. It consists of a mixed liquefaction refrigerant cycle with a separate cycle for pre-cooling the natural gas feed and the liquefaction refrigerant. A gradual vaporisation and warm-up of the refrigerant against the NG cause the process of cooling otherwise referred to as auto-cooling examples of the MCMR includes the dual-mix refrigeration process (DMR) and the propane pre-cooled MR process (C3MR).

The SMR has been observed to have a lower production cost than the C3MR because it requires less equipment to set up (Barclay and Shukri, 2000) comparable in cost only to the EtPLT (Hajji *et al.*, 2019). However, it may not be suitable for the operation of large train LNG production (Lee *et al.*, 2016; Hung *et al.*, 2022). Also, Nasr and Connor (2014) and (Mokhatab and Messersmith, 2018) observed that the MCMR is the most preferred LPT for more than half of the base load of LNG plants because of their potential to be deployed in large trains of up to 8 MTPA.

C. The cascade-based liquefaction process technology

The Cascade-based LPT (CLPT) employs a cascade of pure or mixed refrigerants for NG liquefaction. The pure-refrigerant-based cascade processes typically employ methane, ethane, and propane as in the case of the classical cascade or a mix of refrigerants including ethane, propane, and butane as in the case of the SMR and C3MR (Nasr and Connor, 2014). The CLPT is reported to have the following advantages

(1) Plant shutdown is less likely to occur as a result of the loss of a train.

(2) The facilities allow for an easy shift from LNG recovery to LPG recovery in response to changes in market demand

(3) Utilise simple operation principles with proven reliability as in the case of the Conoco Phillips optimised cascade process

D. Hybrid liquefied process technology

The Hybrid liquefied processes **(**HLPT**)** are process structures that incorporate more than one element of the previously highlighted NG liquefaction technologies for achieving greater process efficiencies, flexibility and cost-effectiveness. Examples include the Axens liquefying process and the AP-X process.

2.1.4.3 Process Efficiency

Ideally, the feed gas inflow into a NG process is usually deployed for LNG production and plant fuel/power functions (Songhurst, 2018). Liquefied natural gas process efficiencies can be employed as a benchmark for comparing the competing processes (Doug Yates, 2002). LNG process efficiency is defined as the relative feed gas fraction that has been utilised for LNG production (Rasberger, 2007). Conversely, Cacciapalle *et al.* (2021) define it as the specific power required for liquefying a unit mass of LNG. In both cases, the implication is that the lower the fuel consumption, the lesser the power required for the NG liquefaction and effectively the better the efficiency of the process. Based on study reports, the average fuel consumed by typical LNG plants falls within the range of 8 - 15% (Mokhatab *et al.*, 2014; Songhurst, 2018; Zhang *et al.*, 2020). This implies a process efficiency range of 85-92%.

Essentially, LNG process efficiencies are affected by several factors including the feed gas composition, environmental conditions (temperature, pressure, etc.), process line sizes, and the efficiencies of compressors and drivers (Rasberger, 2007; Cacciapalle *et al.*, 2021).

A. Effect of feed gas composition, temperature, pressure and train size on liquefaction efficiency

The composition of the LNG feed gas is usually a function of the country from which the feed gas is mined. Thus it differs globally from one location to another. In the context of LNG production, the purity of LNG feed gas is dictated by the amount of its methane composition. For example, Anosike *et al.* (2016) studied the NG composition of associated gas in Nigeria and concluded that its methane content ranged between 78-89% while the rest of the compositions were outright impurities (Carbon (iv) Oxide, Nitrogen, Hydrogen sulphide) considered unsafe for the environment, water and hydrocarbons that lowered the heating value of produced LNG (Table 2.3).

Table 2.3: Composition estimates for Nigerian natural gas

SN	Natural gas constituents	Independent Laboratory data	Company Data
1	Methane (CH_4)	78.81	0.88748
2	Ethane (C_2H_6)	10.46	0.04402
3	Propane (C_3H_8)	4.62	0.02572
4	Iso-Butane, (C_3H_{10})	0.79	0.00553
5	N-Butane, (C_4H_{10})	0.97	0.00843
6	Iso-Pentane, (C_5H_{12})	0.31	0.00265
7	N-Pentane, (C_5H_{12})	0.27	0.00195
8	N-Hexane, (C_6H_{14})	0.21	0.00174
9	N-Heptane+, (C_7H_{16})	0.10	0.00178
10	Carbon Dioxide, (CO_2)	2.59	0.01957
11	Nitrogen, (N_2)	0.61	0.00113
12	Water, (H_2O)	0.26	0.00000
13	Hydrogen Sulphide, (H_2S)	0.001	0.00000

Source: Adapted from (Anosike *et al.*, 2016)

The processes of removal or reduction of these unwanted materials to the required specification such as Carbon (iv) Oxide and sequestration (Veskovic *et al.*, 2022) impact the efficiency of the NG conversion process.

Also, it has been shown that some LNG process technologies achieve higher efficiencies when process operations are conducted at low temperatures. For example, when conducted at 10 to 15^{o}C lower than the design operating temperature specifications, Cacciapalle *et al.* (2021) observed that the AP-C1, AP-DMR and AP-C3MR achieved higher liquefaction efficiencies. Similarly, Zhang *et al.* (2020) concluded that plant efficiency could be reduced by up to 25% when operated in temperatures that are higher than ambient. Also, Pajączek *et al.* (2020) studied the integration of pressure letdown stations with LNG units. They concluded that the energy recovery from the approach significantly improved LNG plant efficiency and was possible to reduce LNG thermos-ecological costs by up to 8.2%. Similarly, Zhang *et al.* (2020) showed that increased operating pressures result in increased process efficiencies.

Regarding line (train) size effects on plant efficiencies, it has also been shown that the phase of cooling medium (refrigerant) deployed in liquefaction operations coupled with the train size could affect process efficiencies (Doug Yates, 2002). For example, large trains typically possess large flow areas and require large operating pressures. Thus if an all vapour refrigerant is deployed in such processes, the plant efficiencies become lowered (Cacciapalle *et al.*, 2021).

B. Effect of compressors and drivers on LNG process efficiency

Compressors in LNG plants function by removal of water and generation of pressure required for NG liquefaction and are considered the most critical component of LNG process facilities as their efficiencies transmit directly on LNG process efficiencies and increased greenhouse reduction in the form of Carbon(iv) Oxide reduction, and waste heat recovery (Meher-Homji *et al.*, 2007). This implies that the proper decision must be made with respect to the right choice of compressors and turbine drive requirements.

C. Effect of feed gas availability and reliability on LNG process efficiency

LNG process efficiencies are easily affected by the availability and reliability of the feed gas and equipment. The turndown rate of LNG plants in the face of intermittent feed gas availability can be problematic in terms of plant efficiency as the plant will lack the ability to attain stable operation which may lead to frequent turndowns and shutdowns. Doug Yates (2002) reports that turndown ratios below 40% of the design level, can affect plant efficiency due to poor flow distribution in heat exchanger columns.

2.1.4.4 Equipment availability, reliability and total maintenance

Liquefied natural gas operations require the use of several types of equipment including heat exchangers, turbines, compressors, shipping vessels and ancillary equipment. The operational availability and reliability of these equipment affect the profitability of the business. Equipment available ensures continuous production, lowered turndowns and shutdowns due to increases in system failure rates. It also reduces the likelihood of attaining in terms of LNG production, the expected design capacity. Thus for this to be made possible, system redundancy and total maintenance strategies must be adequately implemented (Kwang Pil *et al.*, 2008; Gowid *et al.*, 2014, 2015).

Total maintenance refers to the entire types of maintenance activities including corrective, preventive and shutdown maintenance done on equipment during the LNG production system's life cycle. Several authors have undertaken studies on the maintenance of LNG components or systems. For example, Cheng *et al.* (2009) proposed an expert system approach to LNG terminal emergency systems. The outcome of the study was the development of a fault tree analysis-Fuzzy intuitionistic model. Sarkara *et al.* (2012) carried out a five-and-a-half-year empirical data study to estimate the failure rates and availability of eight gas turbines in Tripura, India. They concluded that the gas turbines had an availability range of 0.30 to 0.98, a failure rate of 1/100 to 1/1000 hours and a mean time to repair range of 2 to 8 hours. Calixto (2016) treated the concept of LNG equipment availability, maintainability, and reliability with emphasis on reliability prediction and simulation.

Also, Hassan *et al.* (2016) employed the concept of Markov processes to model the operating, degraded and failed states of an LNG production system. They concluded that it was necessary to model a degraded state as a preventive maintenance state to allow for the facilitation of effective maintenance planning by administrators. In addition, Seo *et al.* (2020) estimated the availability of air compression and nitrogen generation systems in

LNG floating, production, production and offloading platform. They concluded that redundancy was the most important factor that ensures the availability of the facilities.

These researches and their corresponding outcomes underscore the importance of total maintenance to the availability of the LNG process. However, it appears from the observed study reports that no consideration has been given to the estimation of the availability of the LNG production system from a holistic perspective where the interaction of all the system availability factors is seen to be interacting towards revealing the status of the system. The existence of this study should be able to provide information on the critical equipment that affect the overall availability of the LNG production system.

2.1.4.5 LNG operation site conditions

The site conditions in which LNG operations are conducted usually influence the life cycle costs of LNG businesses. For example, Songhurst (2018) compared the differing liquefaction plant cost of the Queensland and North-West Australia LNG plants and opined that the latter plant cost more because it is relatively more remotely located than the former. Other factors as identified by USDA and USEA (2016) and Habibullah and Kikkawa (2018) include

i. Suitability for berthing LNG ships and carriers
ii. Suitability of feed gas pipeline construction (USDA and USEA, 2016)
iii. Prompt material availability
iv. Land titles and ownership
v. Greenfield/brownfield site conditions

Habibullah and Kikkawa (2018) posit that as much as 5% of total capital costs can be saved if LNG plants are properly located. Songhurst (2018) proposes a method of liquefaction plant cost estimation which takes uses site condition estimation values as a multiplier of the expected regular plant costs.

2.1.5 Economic factors affecting natural gas liquefaction

The economic factors that affect the liquefaction of NG include the lifecycle costs, capital expenditure (CAPEX) and operating costs (OPEX) over the expected plant lifetime, heating/cooling medium, compressor/drivers and ancillary equipment.

2.1.5.1 Liquefied Natural Gas Life Cycle cost and elements

Life cycle costing (LCC) can simply be defined as a product's measure of resource consumption over the entire product's life cycle. Woodward (1997) captures it aptly as "The life cycle cost of an item is the sum of all funds expended in support of the item from its conception and fabrication through its operation to the end of its useful life." Kadarova *et al.* (2015) added that apart from its major goal of product costing over a lengthy period, LCC also involves verifying the economic returns of that product over the LCC focus period. Several benefits of LCC have been identified (Emblemsvåg, 2003; oneclicklca, 2021). Some of these include project long-term value, improvement in reliable planning and reduced risk, proactive cost management and improvement in design and procurement processes.

The goal of a typical LNG project is the optimisation of project LCC with a strong emphasis on cost reduction (Coyle et al., 1998). Thus a starting point to achieving this is the identification of potential LCC elements of a typical LNG plant. A few attempts at LNG plant cost breakdowns have been made in the literature.

Coyle *et al.* (1998) essentially analysed cost breakdowns by combining location and process influences on the LNG project. Based on these attempts, a typical LNG plant cost elements are those attributed to process technologies, feedstock compositions, number, capacity, and type of liquefaction trains, design margins, site selection, plant layout design and engineering specifications, type and number of mechanical drivers, cooling and heating medium, schedule (life cycle), feed gas conversion and power, storage and transportation utilities.

Kotzot *et al.* (2009) identified material cost, site preparation cost, marine facilities cost, labour cost and financing cost as the five major factors that impact plant selection. Similarly, Songhurst (2014) and Songhurst (2018) made two classification forms. The first was made based on the plant area occupied by different project activities while the second considered cost on basis of project categories. They broke down these factors as a function of site preparation, feed gas purification, fractionation, liquefaction, refrigeration, utilities and off-site facilities. For the plant to be operational, the expenditures that will be made with respect to these cost elements are grouped into Capital Expenses (CAPEX) and Operational expenses (OPEX).

2.1.5.2 Capital expenditure, operational expenditure and elements

CAPEX elements include trains, liquefaction equipment, utilities, infrastructure and ownership costs (Coyle *et al.*, 1998; Omar, 2016). The OPEX elements have been identified as those tied to operations, maintenance, power and material supplies management, depreciation, emission penalties, consumables, personnel and overhead (DiNapoli and Yost, 1998; Songhurst, 2014, 2018; Hönig *et al.*, 2019).

Each of the cost elements impacts the overall LNG LCC and as such requires adequate management especially at the design and planning stage to ensure cost-effective processes. For example, Songhurst (2018) carried out a study on the CAPEX and OPEX performances of twenty-five LNG plants across the world. The results revealed that depending on the economic and technical factors influencing their operations, LNG plant CAPEX ranged between 611 and 4286 $/TPA (2.1 and 15 $/MMBTU) while the OPEX ranged between 45 and 100% of CAPEX.

The life cycle cost of LNG plants significantly influences their viability and profitability. For example, it is projected that the CAPEX of LNG operations is likely to increase within the next ten years due mainly to rising product demand, inflation, transport cost, and global economic dynamics (DNV, 2020; IEA, 2020; Ayuk, 2022). The effect of these will be felt on the final investment decision (FID) that determines if the LNG project should proceed, be delayed, or be cancelled.

2.1.6 Liquefied natural gas transport

LNG transport entails the distribution of produced products to the consumer. It is a very important aspect of the LNG value chain. In recent times, a rough estimate of the cost of carrier charter can be as high as 20 to 50% of the delivery price of LNG (Bipul, 2016; Eikens, 2020; Shakirov, 2020; Molnar, 2022).

Depending on the scale of LNG produced, the product can be transported using different transportation modes which include trucks/rails and by sea (Thomas and Dawe, 2003; USDA and USEA, 2016). Distribution of small-scale LNG products is usually carried out by trucks/rails. This is especially necessary where demand centres are remotely located or access/construction by pipelines is impractical. An example of such is Japan's JAPEX system which has been used for trucks/rails LNG supply for about three decades now (USDA and USEA, 2016).

Concerning large-scale LNG production where product demand is majorly concerned with export or offshore LNG delivery the most convenient means of transport is via sea routes (Sinha and Wan Nik, 2012; Raj *et al.*, 2016a). This process involves the use of shipping vessels which have been designed specifically for LNG carriage and transport across sea routes. These types of shipping vessels called LNG carriers are typically large sea vessels with a capacity range of 130000 – 260000m^3 (Tu, 2019). Because the vessels have to transport LNG at a very low temperature of -162^{o}C, these vessels are usually double-hulled and insulated to preserve the fluid at the required temperature (Gupta and Prasad, 2003).

2.1.6.1 Factors that affect LNG shipping

It has been reported that the cost of shipping constitutes about 20 to 30% of the total cost of the LNG value chain (Lee *et al.*, 2017; Eikens, 2020). Thus, a thorough estimate of LNG shipping cost is crucial as it is critical in driving decisions regarding the life cycle cost (LCC) of LNG projects. Based on the literature searches undertaken, the cost of any typical LNG shipping activity is influenced by the following factors:

A. Burn-off gas (BOG)
B. Propulsion system
C. Charter costs
D. Fuel consumption
E. Fuel type
F. Vessel speed
G. Brokerage and insurance fees

A. Burn off gas

Boil-off gas (BOG) is the gaseous form of LNG that is given off during storage, transportation and loading/unloading of LNG. The burn-off action, which is an inevitability during storage and shipping is one of the major challenges in LNG shipping. BOG losses are generally affected by vessel speed and prevailing environmental conditions. Bahgat

(2015) and Kim *et al.* (2019) report that potentially between 0.1 to 0.6 % per day of BOG is lost during LNG transportation depending on the vessel speed. BOG losses are disadvantageous in three major ways (Sedlaczek, 2008; Kim *et al*., 2019; Kalikatzarakis *et al*., 2022).

(i) They cause a reduction in the volume of the product delivered to customers

(ii) As harmful emissions, they impact negatively on the environment when released

(iii) Create overpressure in tanks with the potential to lead to accidents and negative environmental consequences

However, the goal of its management is to minimise the rate at which the BOG is lost. One of the ways of limiting BOG losses is its use as vessel fuel. Effective use of BOG as fuel serves as an alternative to actual vessel fuel and thus reduces the cost of LNG transportation. Most LNG carriers are designed with propulsion systems that utilise BOG releases (Mokhatab *et al.*, 2014; Fernández *et al.*, 2017).

B. Propulsion Systems

LNG carrier propulsion system types include steam turbine (ST), dual fuel diesel electric (DFDE), tri-fuel diesel electric (TFDE), M-type, electronically controlled, gas injection (MEGI), low-pressure two-stroke engine (XDF), diesel with re-liquefaction (DRL), and others. Any of these propulsion systems is adequate for use by LNG carriers. However, the type of propulsion system utilised impacts on the overall cost of LNG transport in terms of the amount of BOG, fuel consumed, reliability, environmental friendliness and overall life cycle cost (Sinha and Wan Nik, 2012).

Currently, the two most used propulsion system types are the ST and DFDE. The ST propulsion system had been in use exclusively until 2007 when the DFDEs were introduced (Numaguchi *et al.*, 2009; Grzesiak, 2018). Due to their relative superiority in terms of fuel consumption and environmental friendliness, DFDEs have been growing and gaining popularity over the ST systems. DFDE systems have been confirmed to be more efficient (42%) than ST systems (29-32%), they emit relatively lower amounts of CO_2 into the atmosphere and possess a greater level of BOG treatment flexibility (Fernández *et al.*, 2017; Grzesiak, 2018; Attah, 2020). Figures 2.1 and 2.2 show the trend of adoption and the current volume of existing ST and DFDE propulsion systems respectively.

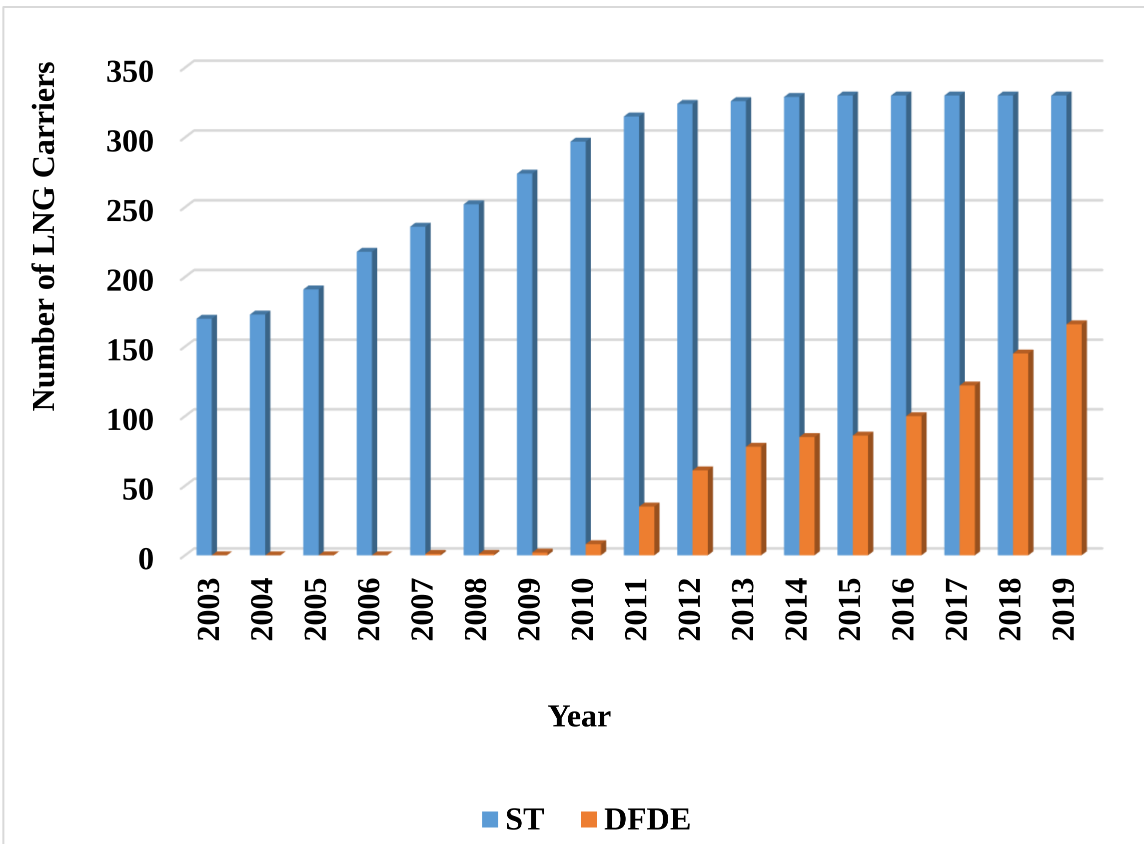

Figure 2.1: Trend of the Steam turbine (ST) and Dual Fuel Diesel Engine (DFDE) adoption between 2003 and 2019

Adapted from (Serpi and Porru, 2019)

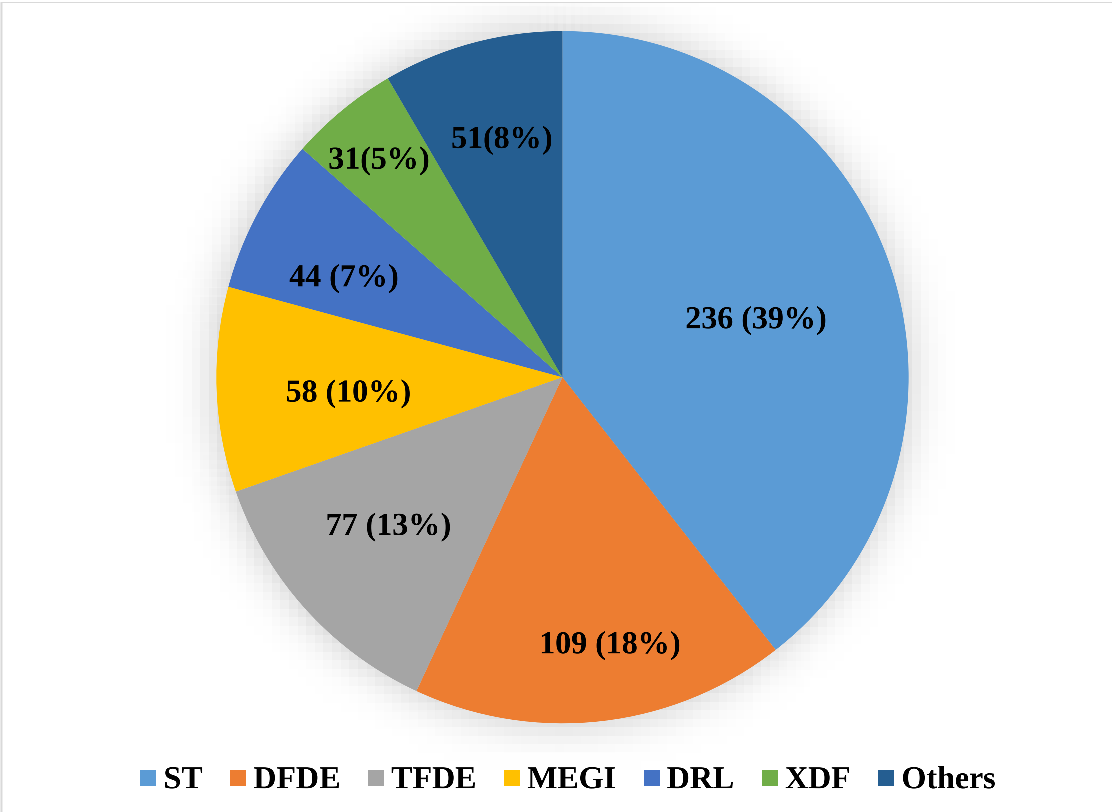

Figure 2.2: Volume of propulsion systems existing in LNG carriers by 2021

Adapted from (Shakirov, 2021)

C. Charter cost

LNG charter cost significantly impacts the overall product delivery price and may cost as much as 25-60% of the total shipping expenses (Rogers, 2018). It refers to the unit cost of renting LNG shipping vessels and is usually expressed in $/day values. LNG carriers may be chartered based on long-term contracts [time-based charter] or on-the-spot market agreements [voyage-based charter] (Plomaritou, 2014; Baatz, 2018). Typically, the cost of fueling the vessel is not a component of the charter cost as this is the responsibility of the charterer. However, ship maintenance cost is the responsibility of the ship owner and thus may be reflected in the charter cost (UK Defence Club, 2021).

The charter cost differs from one ship owner to another but is dependent on multiple uncertain and transient factors. These factors include the number of carriers available for charter, the supply-demand balance on the shipping market, the number of liquefaction plants in operation, total shipping capacity, the price of crude oil, and the price of LNG exports (Shakirov, 2020; Lyridis, 2022).

D. Fuel types

The types of fuel used by LNG carriers also affect the cost of transporting LNG. Generally, all ship fuel types are grouped into three categories based on the percentage of their Sulphur content. These categories are ultra-light Sulphur gas oils (ULSFO) [<0.1% Sulphur], light Sulphur gas oils (LSFO) [0.1-1% Sulphur), and crude oil residuals heavy Sulphur gas oils (HSFO) [1 - 3.5% Sulphur) (Uhler *et al.*, 2016; livebunkers, 2022; Oiltanking, 2022). Various fuel types exist either as pure forms or blends of these categories to accommodate the different propulsion systems as well as meet environmental pollution regulations.

The HFOs which belong to the HSFO class are considered to be the most widely used fuel types because of their relative availability and lower costs when compared to other crude oil distillate-based fuel oils (Luijk *et al*., 2020; Kouzelis *et al*., 2022). However, due to the need to cut down the level of greenhouse gas (GHG) emissions, the use of LNG as a marine fuel has become increasingly popular (Herdzik, 2015; Thomson *et al*., 2015; Xu *et al*., 2015). Added to that, LNG prices have generally been lower than those of the HFOs over the past decade (Salem *et al*., 2014; Eise Fokkema *et al*., 2017; Lee *et al*., 2020).

E. Vessel speed and fuel consumption volume

One of the most significant factors that affect LNG shipping cost and by extension the LNG LCC is fuel consumption. An appreciable amount of research has been undertaken in this area to identify the factors and further understand how the factors influence fuel consumption during LNG transportation. Barrass (2004) formulated a mathematical model that showed that fuel consumption, was affected by the vessel displacement, speed and fuel coefficient [Equation 2.1] with the fuel coefficient being a function of the type of propulsion system utilised by the vessel.

$$F_{ci} = \left(W^{\frac{2}{3}} V^3 \middle/ \varphi \right)_i \tag{2.1}$$

Where,

F_{ci}: Fuel consumed by ship $(tonnes/day)$; W: Vessel displacement $(tonnes)$; V: Vessel speed $(knots)$; φ: fuel coefficient $\left(knots^3 tonnes^{-\frac{1}{3}}\right)$.

The Barrass (2004) model was developed for estimating HFO for ST and diesel engines and will require some modifications for use in LNG fuel consumption estimation.

Also, Bialystocki and Konovessis (2016) deployed a statistical approach to estimating vessel fuel consumption with consideration given to the ship's draft and displacement, weather force and direction, hull and propeller roughness as causal factors. Mersin *et al.* (2017) modified the Barrass (2004) to account for changes in ship displacement while at sea.

Regarding the effect of vessel speed on fuel consumption, three regimes of vessel speed (steaming) are popularly operated by operators in a bid to optimise fuel usage as well as meet customer supply due dates (Rodrigue, 2020).

A. Normal Steaming

This is the cruising of shipping vessels within the maximum design speed range of 20-24 knots. The highest amount of fuel is consumed during normal streaming operations.

B. Slow steaming

In this vessel speed regime, LNG transport is carried out between 18 to 20 knots

C. Extra slow steaming

In this speed regime, the vessel travels at speeds ranging between 15 to 18 knots. This speed is considered quite popular with operators as they try to reduce fuel consumption. Between 2010 and 2016, Axelsen (2018) studied the operational patterns of LNG carriers using Automatic Identification System (AIS) data and concluded that the average carrier speed within that period for all ships observed was 16.44 ± 2.51 knots.

D. Minimal cost streaming

This is the slowest ship speed class and the vessel speed range lies between 12 to 15 knots.

Concerning the volume of consumption, HFO and LNG unit consumption volume differ in addition to the type of propulsion system deployed for shipping. For example, as highlighted earlier, one variant of LNG as a ship fuel type is the BOG. However, for propulsion systems of lower efficiencies such as the ST, running LNG carriers beyond the slow streaming speed will more than likely result in higher fuel requirements such that the use of BOG alone becomes inadequate. In such scenarios, it becomes necessary to augment BOG with fuel oils. This also will come as a disadvantage to the LNG carrier in terms of the extra cost of fueling and lowered LNG storage capacity brought about by the space taken up by the fuel oil augmentation.

2.2 Life Cycle Costing Process

The importance of accurately placing a cost on a product has become a critical consideration and can make or mar the survival of businesses (Lessner, 1991; Lepădatu, 2011). Producing a good requires the consumption of resources obtained at a price (Yu-Lee, 2002; Troelsen, 2006). This price is called the cost of the resource or product consumed. Product costing or LCC is the process of studying and keeping track of all expenses that are accrued in the course of producing and selling a product, from raw material purchases to expenses associated with conversion, value addition and transport to the place of consumption (Rowley, 2017; Drury, 2018).

Costing systems play an important role in various managerial functions some of which includes aiding in the provision of various cost data (Škoda *et al.,* 2014), planning and control and strategic decision-making processes (Brignall *et al.,* 1991). In addition, Business financial statements, tax computation and budgeting processes would be prone to errors if prepared from inaccurate product cost information (Fisher and Krumwiede, 2012). These could effectively lead to understatements or overspending, creating financial stress and impacting the performances of affected organizations' (Oluwagbemiga *et al.*, 2014).

For a manufacturing organization to remain competitive, its products must be made at the minimum cost consistent with the required quality and function of the product (Bae *et al.*, 2007; Xu *et al.*, 2009; Vasili *et al.*, 2011). This minimum cost should be the True Economic Cost of the product. Some of the factors that determine the True Economic Cost of a product are Design Cost Drivers, Marketing Cost Drivers and Supply Chain / Purchasing Cost Drivers. An accurate product cost will enable manufacturers to make the right decisions regarding concerns such as production cost management, product price determination, product profitability management, and Product portfolio management.

It is thus clear that the accuracy of product costing is therefore very crucial for any manufacturing business, especially in the areas of purchasing, design and redesign, reengineering, retooling, packaging and final investment decisions (FIDs).

2.2.1 Life Cycle Costing Approaches

Essentially, there are two broad categories of product costing approaches exist namely specific order costing (SOC) and continuous operation/process costing (COC). SOC is a method of costing in which work is considered in the form of jobs, batches, and contracts (Eydman, 2017; Aisha, 2021). It is a method used by organisations to meet specific orders made by individuals or customers. The COC on the other hand considers the system as a series of repeating units or processes to which costs are charged. Thereafter, these costs are averaged over the number of units utilised. Examples of the COC approach include process costing, operation costing, unit costing and activity-based costing (Kolosowski and Chwastyk, 2014). Clancey (2021) reported that COC is a particularly popular activity in the oil and gas, textile and food processing industry.

2.3 Life Cycle Cost Models

The RTO (2007) report defines LCC Costs models as a methodology that produces cost estimates as outputs formulated based on a set of mathematical or statistical relationships. LCC Costs models are differentiated based on the linearity and non-linearity characteristics of the costing methods. Adapting the RTO (2007) and the Seuring *et al.* (2008) reviews, LCC models can be classified as Linear Homogeneous, Optimisation, Quasi-Dynamic, Estimation, and Dynamic models.

Linear Homogeneous models refer to LCC models in which the model output is proportional to the inputs and as such, is scaled equally to the latter. It is generally referred to as a ‘constant returns to scale’ model. Seuring *et al.* (2008) observed that this approach to costing real systems may not be realistic since real systems largely exhibit non-linearity behaviour. The Optimisation LCC models on the other hand are those in which the LCCs are done using optimisation approaches. These approaches could be mathematical programming or heuristics. The quasi-dynamic LCC models refer to those models that act as a compromise between static (steady-state) and dynamic models. They may include time series, Markov chains and Markov processes.

The dynamic model category involves the use of models to explain system costs that develop over time. Examples of such include the use of simulation methodologies such as Monte-Carlo methods, system dynamics and discrete event simulation (Wang *et al.*, 2012; Vandoorne & Gräbe, 2018; Mousavi *et al.*, 2022; Rahn *et al.*, 2022). RTO (2007) reveals that the most and least utilized of these methods are the estimation and simulation methods respectively.

2.4 Liquefied Natural Gas Life Cycle Costing Models

The literature reveals that LNG LCC models are sparse. It could be speculated here that this sparsity could be attributed to the scope of the costing process which is mainly client-contractor specific. As such, there may be a desire by the clients and contractors to keep information outside the public domain. Nonetheless, a few attempts have been made in this area and are here highlighted.

Coyle *et al*. (1998) provided a framework for LNG life cycle estimation. This framework was based on the integration of various LNG cost elements with emphasis placed on the use of time value of money and internal rate of returns as system evaluation parameters. However, the study was not specific on the appropriate modelling approach for executing the framework. In like manner, Kawauchi and Rausand (1999) identified some processes for undertaking LCC analysis in the oil and chemical process industry. These processes were problem definition, cost element definition, system modelling, data collection, cost profile development and evaluation.

Agbon (2000) carried out an economic analysis of the Nigerian LNG project as a new entrant into the global LNG supply market. The analysis focused on the upstream, midstream and downstream sectors of the project using global liquefaction, NG and LNG pricing, shipping for estimation and potential demand for the Nigerian LNG. The author concluded that although the markets in Europe and the USA were profitable for the Nigerian supply, those in Japan and India were concluded as not profitable.

Although the model provided information about the Nigerian LNG, there is a need for a more in-depth analysis as the technical and five (5) economic factors considered appear little and inadequate. Also, the research was conducted about twenty years ago and the dynamics of the industry have changed significantly over the last decade. For example, the Nigerian LNG has been making supplies to countries like China and India at a profitable level.

Hirschhausen *et al.* (2008) carried out a lifecycle-based financial viability analysis of an LNG regasification terminal based on factors such as investment costs, LNG volume regasified per annum, NG and LNG prices as well as considerations for annual price increases, staffing and interest rate (10%). Based on the Net present value (NPV), and internal rate of return (IRR) as tools of measure, they concluded that the project has a very high return.

Omar (2016) undertook an LCC analysis of a liquefaction process in Malaysia with the major focus being the chemical and thermal process costs of LNG conversion. It was concluded that cryogenic multi-flow heat exchangers exhibited the most economic impact on the process compared to other critical components in terms of their fixed capital investments. Also, Raj *et al*. (2016b) undertook a techno-economic assessment of an LNG facility in Canada. The study was done on two trains of 5 MTPA each. Adopting a CAPEX of $1200/TPA, 12% cost of capital and 25 years projected plant life, the unit cost of production ranged between 7.8 and 9.1 $/MMBTU for two feed gas sources considered. It was concluded that total liquefaction cost was mostly influenced by the CAPEX, Feed gas supply cost, and discount rate.

Nagi *et al*. (2016) carried out an economic comparative analysis of LNG technology and gas-to-liquid (GTL) technology using the Nigerian natural gas production environment as a basis. Multiple technical and economic factors including capital expenditure, operating expenditure, natural gas Price, discount rate, equity, royalty, tax, liquefaction losses, and shipping. The result of the study concluded that the LNG production venture was profitable with positive NPV and IRR=24%. However, the input data utilised were mainly obtained as estimates rather than from source extraction.

A costing analysis based on the use of capital budgeting methodology was used to determine the profitability of the oil and gas investment project in Vietnam (Mentari and Daryanto, 2018). The analysis outcome showed the Net present value (NPV), internal rate of return (IRR), and profitability index (PI) to be 8.96×10^9, 22.10 %, and 144.59%, respectively. From the results, the authors concluded that the industry was quite profitable and economically viable.

Hönig *et al.* (2019) carried out a techno-economic evaluation of commercial LNG production in the European Union (EU). The technical evaluation procedure involved a quantitative evaluation of the NG purification process and liquefaction processes, while the economic analysis involved the assessment of the economic viability of the LNG production operation. The results obtained showed that the project was viable given that the NPV of the project was determined to be positive.

Da Silva Sequeira (2019) undertook an economic viability study of the life cycle of the LNG business in comparison to that of the gas-to-liquid (GTL) process. The analysis which was done using the Monte Carlo simulation method considered twelve (12) LNG technical and operational factors as inputs namely feed gas price, plant capacity, carbon, and thermal efficiency, capital expenditure (CAPEX), operational expenditure (OPEX), products prices, transportations, tax rate, and discount rate.

The author observed that the economic performance of LNG production was mostly affected by the CAPEX, product selling price, feed gas price, and plant efficiency, in that order. Further results revealed that the LNG project was more profitable and attractive (in terms of the NPV and profitability index) as the plant capacities were lower with the maximum economic performance obtained for a plant capacity of 4.25 MTPA. Furthermore, the study showed that the most profitable LNG project case scenario should be one in which the CAPEX ≤ \$1,500/TPA, product price ≥ \$13/MMBtu, and feed gas ≤ \$2.80/Mcf (\$9.89 × 10^{-5}/m^3gas).

2.5 System Dynamics and LNG LCC Modelling

System dynamics (SD) is a time-based modelling method that captures the activities of a system over time (Coyle, 1996; Sterman, 2000). It allows the inflow and outflow of information and materials through states described in time. Some of its major characteristics include its structural allowance for the development of flow and state control behaviour and its long scope of study. Also, the method possesses the ability to analyse systems that are characterised by non-linearity, uncertainties and transience based on causal relationships, interactions and feedback (Richardson, 2001; Koul *et al.*, 2016; Hamoudi *et al.*, 2021(Charles-Owaba & Adebiyi, 2006; Ajayeoba *et al.*, 2019)). System dynamics has been highly recommended for LCC analysis (Rodrigues and Bowers, 1996; Research And Technology Organisation, 2007; Pinto *et al.*, 2019). With respect to LNG literature on life cycle costing involving the use of SD appears sparse.

2.6 Economic Performance Evaluation Models

The LCC of an LNG project will be considered acceptable and worth investing in if the economic performance of the project is satisfactory or acceptable. Economic models are usually deployed to arrive at the state of an LNG plant's economic performance. Based on the literature search (Blank and Tarquin, 2005; Newnan *et al.*, 2012; Panneerselvam, 2012; Farr and Faber, 2019; White *et al.*, 2020), major types of economic performance models for LNG operation performances were identified and is subsequently discussed.

A. Net Present Value (NPV)
B. Breakeven point and quantity
C. Payback period
D. Return on Investment (ROI)
E. Internal Rate of Return (IRR)
F. Profitability Index (PI)

A. Net present value

The net present value (NPV) of an investment is defined as the value obtained from the difference between the present worth of accumulated profits and the present worth of initial investment over an acceptable rate of return (Equation 2.2). It provides information on the prospect of investing in a project in terms of the current monetary value. It is a tool that is used frequently to aid investors' decisions regarding LNG investment, especially regarding the final investment decision (FID).

$$NPV_{T^*} = \left(\sum_{t=1}^{T^*} C_t \, (1+i)^{-t} \right) - I_0 \qquad (2.2)$$

I_0: Initial investment, t: Operation time, C_t: Cash flow in time t, T^*: Time t at which the NPV analysis is done, i: Rate of return

Farr and Faber (2019) the investment decision rule that applies after the NPV of a project has been determined are

(i) Accept to execute project if NPV_{T^*}>0

(ii) Indifference if NPV_{T^*}=0, and

(iii) Reject execution of project if NPV_{T^*}<0

B. Breakeven point and quantity

This breakeven point (BEP) takes into consideration the time it takes for the sum of the periodic revenue in an investment to reach the value of the initial capital investment made in the project while the breakeven quantity (BEQ) refers to the volume of product sold that produces the breakeven revenue (Equations 2.3 and 2.4).

$$BEP = time \, \{Revenue = total \; cost \; of \; investment\} \qquad (2.3)$$

$$BEQ = Quantity \; of \; sales \, \{Revenue = total \; cost \; of \; investment\} \qquad (2.4)$$

They are considered to be one of the easiest methods of determining the feasibility of a project (Mentari and Daryanto, 2018; Cox, 2022; Shaw, 2022) and can measure profit and losses at different levels of production and sales. However, one major disadvantage of using the BEP in its basic forms for performance evaluation is that it does not consider the time value of money and as such may not convey very accurate results. Regarding this, Farr and

Faber (2019) opined that this can be resolved by considering the period in which the cash flow elements are computed.

C. Payback period

This refers to the amount of time required for the cumulative profits of an investment to equal the cost of investment. It is also described as the number of periods required to pay back the amount of investment with positive net income (Tarver, 2022). Two types of payback periods exist namely conventional payback period (CPP) and discounted payback period (DPP) (Farr and Faber, 2019). The CPP involves analysis in which the cash flows are treated as being equal in time value (Equation 2.5) while the DPP involves consideration of the time value of money (Equation 2.6). Thornton (2019) states that for a typical LNG production venture, the expected payback period is 10 years.

$$CPP = (T-1) + \frac{\left(\sum_{t=1}^{t=T} C_t\right) - I_0}{C_{T+1}} \qquad \left\{\left(\sum_{t=1}^{t=T+1} C_t\right) - I_0 \geq 0\right\} \qquad (2.5)$$

$$DPP = (T-1) + \frac{NPV_T}{C_{T+1}(1+i)^{-(T+1)}} \qquad \{NPV_{T+1} \geq 0\} \qquad (2.6)$$

Where,

I_0: Initial investment, t: Operation time, C_t: Cash flow in time t, T: Time t at which the sum of I_0 and total cash flow ≥ 0, i: Rate of return

D. Return on investment

This is considered the most frequently used economic performance measure (Newnan *et al.*, 2012; Farr and Faber, 2019). It refers to the (percentage) fraction of benefits made from an investment when compared to the value of the initial investment within an investment window (T^*). The typical mathematical model used for computing ROI is described in Equation 2.7. ROI may be computed with or without consideration for the time value of money. However, the effect of the time value of money provides a more realistic value of the ROI. The ROI $(\%/time)$ can be positive or negative. Farr and Faber (2019) posit that when the ROI is negative, it implies that there is no quantifiable gain in investing in the project and vice-versa when positive.

$$ROI = \begin{cases} 100\left(\sum_{t=1}^{t=T^*} C_t - I_0\right) \Big/ (T^* I_0) & \{No\ time\ value\ of\ money\} \\ 100[NPV_{T^*}] \Big/ (T^* I_0) & \{time\ value\ of\ money\} \end{cases} \quad (2.7)$$

E. Internal rate of return

The internal rate of return (IRR) refers to the interest rate that can be obtained such that the NPV of an investment is equal to zero (Equation 2.8).

$$IRR_{T^*} = i\ \{NPV_{T^*} = 0\} \quad (2.8)$$

The IRR provides information on the maximum acceptable rate of return on investment (Blank and Tarquin, 2005; White *et al.*, 2020). Thus, if the IRR is equal to or higher when compared to the investors' minimum acceptable rate of return (MARR), then the project is considered economically viable, otherwise, it is rejected (Ruegg and Marshall, 1990; Farr and Faber, 2019). The process of IRR estimation is somewhat rigorous and may require the adoption of trial and error methods to determine it.

F. Profitability Index

The profitability index (PI), also referred to as the profitability investment ratio is a benefit-cost ratio indicator that provides information on the profitability of an investment (Newnan *et al.*, 2012; Farr and Faber, 2019). It provides a degree to which the investment is attractive (Chen, 2022). It is computed as the ratio of the present worth of an investment to the initial capital investment (Equation 2.9). A PI value greater than unity infers that the project is profitable.

$$PI_{T^*} = NPV_{T^*} \Big/ I_0 \quad (2.9)$$

A summary of the studies on life cycle costing models reported in this work (Table 2.4) shows that regarding the application of economic performance models, the NPV (62.5%) is the economic model most utilised in LNG LCC analysis. The others in order of the more frequently utilised are IRR (37.5%); PI (37.5%); CPP (25.0%); DPP (12.5%) and CROI (12.5%). The break-even analysis and discounted ROI (DROI) performance indicators were not applied.

Table 2.4: Summary of studies with application of economic performance models in life cycle costing

SN	LNG production Economic Analysis study	NPV	Breakeven		Payback period		ROI		IRR	PI
			BEP	BEQ	CPP	DPP	CROI	DROI		
1	Agbon (2000)	0	0	0	0	0	0	0	0	0
2	Hirschhausen *et al.* (2008)	1	0	0	0	0	0	0	0	0
3	Nagi *et al.* (2016)	1	0	0	0	0	0	0	1	1
4	Omar (2016)	0	0	0	0	0	0	0	0	0
5	Raj *et al.* (2016b)	0	0	0	0	0	0	0	0	0
6	Mentari and Daryanto (2018)	1	0	0	1	1	1	0	1	1
7	Da Silva Sequeira (2019)	1	0	0	1	0	0	0	1	1
8	Hönig *et al.* (2019)	1	0	0	0	0	0	0	0	0
	Sum	5	0	0	2	1	1	0	3	3
	Percentage	62.50	0	0	25.00	12.50	12.50	0	37.50	37.50

2.7 Research Gap

From the highlights of the LNG LCC models highlighted in section 2.5, it is clear that although the authors recognized the complex, dynamic and transient nature of the LNG production environment, virtually all quantitative cost estimate methods used for analysis were either, deterministic models, statistical, or time series. However, the nature of the LNG system requires a thorough understanding of the causality relationship of the factors affecting the upstream, midstream and downstream subsystems and how they relate and interact within the dynamic environment.

These interactions may not be clearly understood with the costing models previously used for LNG LCC. In addition, it is already well understood that dynamic systems such as those for LNG production are not incorrectly defined without the presence of feedback (Brehmer, 1989; Sterman, 1989; Sterman, 2000; Thoms, 2011; Hu *et al.*, 2014). These feedback features, which can serve as decision support systems and may influence new adaptive operating and management strategies for improvements and survival of firms in the LNG production environment are lacking in the use of the reported models.

Also, it is clear from literature that the outcomes of the profitability and LCC analysis from the previous reports provide useful information for LNG investments. However, little focus was placed on specifically understanding the degree to which the availability and reliability of the liquefaction equipment and shipping vessels impacted LNG process efficiency. This may have been due to the limitations inherent in the Life cycle costing approaches deployed in the reported works.

The system dynamics methodology is considered appropriate for improving on the limitations of the reported models (Rodrigues and Bowers, 1996; Research And Technology Organisation, 2007; Pinto *et al.*, 2019). This is because of its ability to incorporate factors of causality and feedback as well as the provision of a larger pool of information. However, the use of this approach at LNG life cycle costing appears sparse. This alongside the previously highlighted gaps is the concern of this study.

CHAPTER THREE

METHODOLOGY

3.1 Overview

This chapter details the methods used in the estimation of the unit life cycle cost (LCC) of liquefied natural gas (LNG) production systems. This involves firstly, the development of a framework for the LCC of a typical LNG system. Secondly, based on the developed framework, the system dynamics (SD) method was adopted in the design of an LNG plant with considerations given to various activities necessary for its operation and how these activities interact to affect the plant's effectiveness, efficiency and profitability over a period considered in this study. Subsequently, based on the cost estimates of the designed plant and costs of its identified operational activities, a series of system dynamics-based quantitative relations were deployed in the development of the system dynamics-based liquefied natural gas life cycle cost (SD-LNG-LCC) model.

In addition, various economic analysis models were developed for the evaluation of the economic viability of LNG production systems. Finally, the methods used in the validation and evaluation of the SD-LNG-LCC model are presented.

3.2 Life Cycle Costing Framework Development for the Liquefied Natural Gas Production System

Before carrying out the design of the LNG plant, a study of LNG production procedures and practices in ten LNG production plants around the world was carried out using secondary information obtained from literature. Then, a real-time LNG production firm was then considered. After permission was sought and approval obtained, two months were spent observing the firm's production activities.

In addition, personal interactions and interviews were conducted with seven randomly selected plant engineers concerned with LNG production management and administration.

Using the information obtained from literature study, interactions and interviews, three sectors (Table 3.1) were identified to exist in the LNG system. The identified sectors are made up of specific units that are responsible for managing various activities within the plant with the goals of ensuring plant availability and in effect an optimum production process. These specific units which are described in Table 3.1 include financial, production and maintenance management activities.

Using the specified units of the identified sectors, the structure of the LCC for an LNG plant was subsequently developed based on three optimisation goals which are:

1. Maximisation of equipment availability
2. Maximisation of the volume of LNG produced
3. Minimisation of the total LNG production cost

The developed LCC framework for LNG production was described using Figure 3.1. It shows various operational and decision-making activities necessary for the existence of the LNG process, their interactions and corresponding impact on the LCC of the process.

The framework describes the start of the LNG process from the point of capital (equipment) acquisition and the availability of a budget for operational expenses. These are the two activities on which all production, maintenance and product supply operations depend on for a successful LNG business process. On the condition of availability of the feed gas as raw materials, the conversion process of the feed gas into the final product begins via the utilisation of the acquired equipment dependent on the availability of qualified hired operations workforce personnel (Human resources).

Equipment operations, however, are dependent on its availability and the task of ensuring equipment availability is the responsibility of hired maintenance personnel (Human resources). The maintenance personnel is responsible for carrying out various forms of maintenance actions on the deteriorating/degraded equipment to ensure a continuous LNG production process through the minimisation of breakdowns, ensuring its maximum availability in the process. The framework also considers spare parts replacement and their availability (through inventory management) regarding how they affect downtime and in effect the LNG production process.

Table 3.1: LNG production system breakdown into various sectors, specific units within the sectors and the activities for which they are responsible

LNG Sectors	Specific Units	Activities
Financial Management	1. Budgeting/Funding 2. Economic Analysis	1. Estimation of costs (initial and running) related to plant location, upstream facilities, liquefaction, construction, bulk materials, maintenance, feed gas supply and LNG production (CAPEX and OPEX). 2. Identification of cost drivers and LCC estimation 3. Determination of unit LNG production cost and cost of deferred production. 4. Determination of periodic profits/losses obtained made from the LNG operations 5. Estimation of various operational economics evaluation indices.
Production Operation	1. Liquefaction operation 2. Production personnel management	1. LNG production from feed gas 2. Production Process monitoring 3. Securing required manpower for operations activities.
Equipment availability Management	1. Equipment maintenance operation 2. Maintenance personnel management 3. Inventory management	1. Maintenance of equipment and production units 2. Equipment and monitoring and conditioning 3. Installations and modifications 4. Ordering, storage and supply of materials and equipment spares for operations and maintenance services.

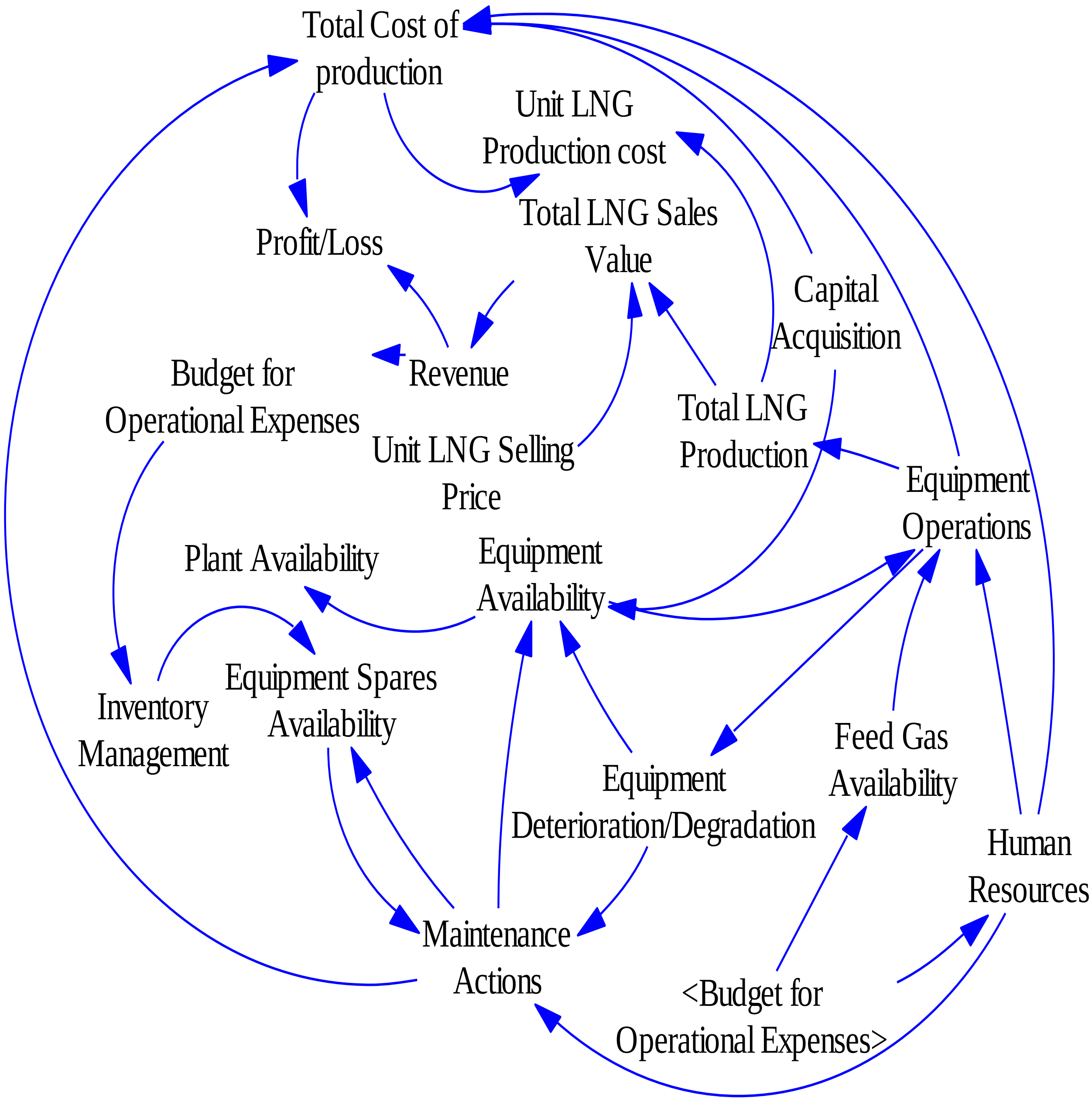

Figure 3.1: The LNG Life cycle cost framework

The LCC of the process was then estimated as the total cost of all the activities taken throughout the operation period chosen in this study. Furthermore, the impact of the total cost of operation on the unit LNG production cost and the profitability of the entire process based on LNG global selling prices was also captured by the framework.

3.3 LNG Production System Design

This section details how the LCC LNG framework was adopted in the design of the LNG plant to capture the behaviour, interactions and dependability of the sectors presented in the LNG production system was then obtained as the integration of all the designed sectors. Given the close relationship that exists between the human resources part of logistics support with the operations, the design of the production operations sector was integrated with the operations personnel design while maintenance operations sector design was also integrated with maintenance personnel design. As such the focus on the logistics support sector design was placed on maintenance inventory management only. The LNG Table 3.1. The design of each of the sectors is discussed in a different sub-section.

3.4 Sector Design Procedure Using the System Dynamics Approach

The production system's design was done using system dynamics (SD) approach. A general SD procedure based on the system dynamic approaches of Coyle (1996) and Sterman (2000) was deployed in the design of all the sectors. The procedure is presented as follows.

For the design of each of the LNG production sector

1. Various SD quantities were identified. These quantities relate to various tasks that are undertaken for different activities in the sector.
2. The use of influence/causal diagram was used to describe the dynamic inter-relationship that exists between any two sector quantities (A and B) as illustrated in Figure 3.2. The arrow sign describes the dependency of the quantity to which it points to (B) on the quantity from which it points from (A) while the polarity on the arrow of the graph provides information on whether the dependent quantity is positively (+) or negatively (-) responsive to a change in the value of the independent quantity.

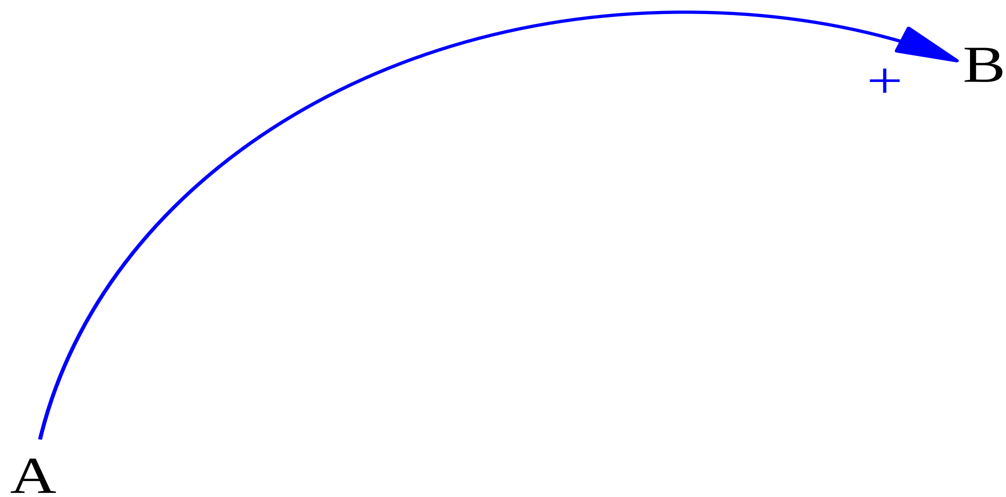

Figure 3.2: A typical system dynamics influence/causal diagram

3. The causal diagram was converted to a stock and flow diagram to distinguish between the flow and accumulation quantities using the input, auxiliary, rate and state recognition principle.
4. A set of dynamic equations was formulated based on the flow and accumulation relationship of the sector quantities.

3.5 Assumptions for the model development

The following assumptions were made in the course of developing the model

1. The sectors are the subsystems of the overall LNG production system
2. The maintenance actions carried out involve spare replacements only. No equipment repairs were considered
3. All the engineers and technicians can undertake maintenance tasks desired.
4. Equipment degradation/deterioration rate follows a Weibull distribution
5. There is no redundant liquefaction equipment in the system
6. The daily demand for the LNG produced in the plant was taken to be equal to the plants' daily production capacity
7. LNG production operations can only be kick-started when all expected capital expenditures and the funding for an OPEX window have been satisfied.
8. The total amount budgeted reflects the sum of all budgets made for all activities that are done in the system.
9. The amount expended on operational expenses (OPEX) is a direct function of the allocated budget
10. OPEX funds for all types of activities are monitored and controlled by a centralised administrative approach.
11. Adequate investment planning has been undertaken by the stakeholders beforehand and the final investment decision (FID) has been made.
12. Customers' orders are not processed during turnaround maintenance periods.
13. Equipment spares and materials and corresponding specifications are known
14. Regarding ship deployment, the highest utilisation priority is given to ships owned by the LNG production firm, followed by those on long-term charter contracts. The least utilisation priority is accorded vessels that are on spot charter contracts.

15. Ship fuel utilisation is predominantly based on LNG burn of gas (BOG). However, fuel oil supplements are used when BOGs are expended.
16. BOG liquefaction technology is inexistent in shipping vessels.
17. Vessel propulsion systems are of the steam engine and the dual fuel diesel electric engine (DFDE) only.
18. Government policy is stable.

3.6 The Financial management sector

The financial management sector was developed for the estimation of plant operation costs, tracking of expenses, estimation of product cost and determination of profit and losses from liquefaction operations. The interacting quantities that make up this sector were identified and their corresponding dimensions were specified (Table B1 in appendix B). The sector was subdivided into three sub-sectors namely; budgeting and funding, TLCC estimation and economic analysis. To develop the SD-LNG-LCC model from an activity-based perspective, the budgeting and funding subsector is first discussed. However, the other two subsectors are presented in sections 3.9 and 3.10 respectively after the operation and maintenance sectors have been developed.

3.6.1 Budgeting and funding sub-sector model development

The budgeting and funding unit is a sub-sector of the financial management sector. The sub-sector concerns activities involved with determining the amount set aside to run the operations of the plant. The quantities identified and corresponding specified dimensions are those of capital expenditure (CAPEX) and operational expenses (OPEX).

The quantities and couplings of the sector shown in its causal diagram (Figure 3.3) and the accumulations and flows (Figure 3.4) describe activities that take place right after the FID and before operations start-up. It includes the cost elements considered in the estimation of CAPEX. The cost elements considered in this work which were adapted from Mokhatab *et al.* (2014) and (Songhurst, 2018) include quantities related to greenfield and brownfield costs, equipment costs, bulk material costs, engineering management costs and owner's costs.

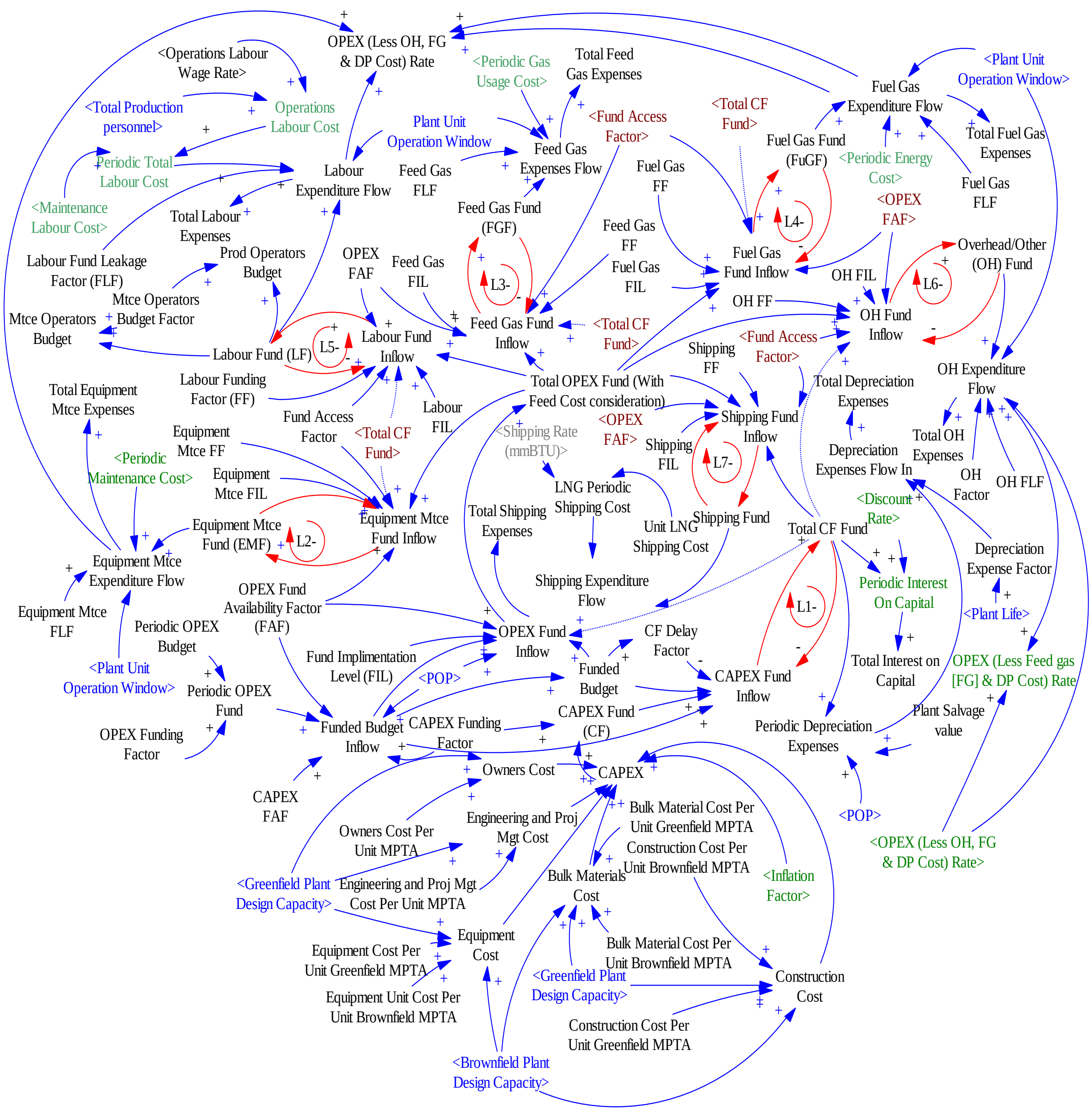

Figure 3.3: Causal diagram description of the LNG budgeting and funding sector

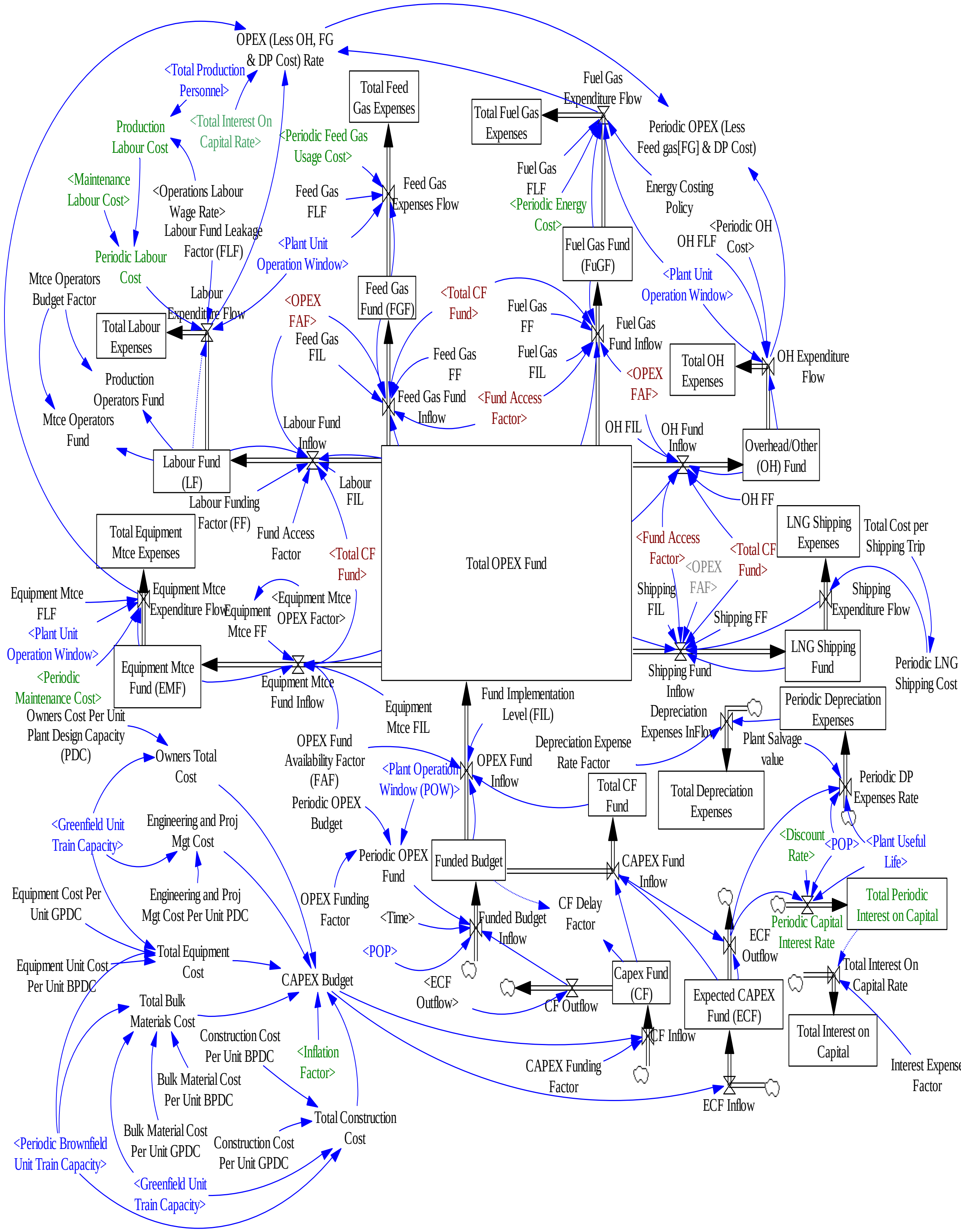

Figure 3.4: Stock and flow diagram of the LNG Finance sector

The OPEX elements considered include the costs of feed and fuel gases, operation (maintenance and production) costs, labour costs, overhead/other costs and LNG shipping costs.

3.6.2 System dynamics equations for the Budgeting Sector

Using Figure 3.4 and the defined quantities (Table B1 in appendix B), fourteen states were identified within this sector. The system dynamics equations were subsequently developed for these states.

(1) The Funded budget

The Funded budget (B^T) refers to the finances set aside at any time for the operation of the LNG process. From Figure 3.4, the B^T is a function of the funded budget inflow ($\dot{B}^T$), the CAPEX fund inflow ($\dot{F}_{EX}^C$) and the OPEX fund inflow ($\dot{F}_{EX}^O$). The variables on which $\dot{B}^T$, $\dot{F}_{EX}^C$ and $\dot{F}_{EX}^O$ as obtained from the stock and flow diagram are dependent are here described.

The funded budget inflow refers to the rate at which the LNG operation is funded in line with the budget that has been made for such a purpose. $\dot{B}^T$ exists as a function of the CAPEX fund ($\hat{F}_{EX}^C$), periodic OPEX fund ($\hat{F}_{EX}^O$), the planning period (t) The POP and the fund availability factors (FAFs) for CAPEX and OPEX [Equation 3.2]. The FAFs describe the frequency in which funds for the budget are made available within an operating window. $\dot{B}^T$ was fixed as $\hat{F}_{EX}^O$ available during the operation period or $\hat{F}_{EX}^C$ within the planning/FID period (Equation 3.3)

$$\frac{dB^T}{dt} = \dot{B}^T - \dot{F}_{EX}^C - \dot{F}_{EX}^O \tag{3.1}$$

$$\dot{B}^T = f\left(\hat{F}_{EX}^C, \hat{F}_{EX}^O, t, t^*, \Omega_{EX}^C, \Omega_{EX}^O\right) \tag{3.2}$$

$$\dot{B}^T = \begin{cases} \left[\Omega\hat{F}\right]_{EX}^O & \{t = t^*\} \\ \left[\Omega\hat{F}\right]_{EX}^C & \{t < t^*\} \\ 0 & \{Otherwise\}. \end{cases} \tag{3.3}$$

$$\hat{F}_{EX}^i = f\left(\hat{B}_{EX}^i, \Psi_{EX}^i\right) = \left[\hat{B}\Psi\right]_{EX}^i \qquad \{i: O, C\} \tag{3.4}$$

While $\hat{B}_{EX}^{O}$ was taken as an input, $\hat{B}_{EX}^{C}$ was estimated as the sum of the CAPEX elements $\left(C_{Own}^{Tot}, C_{Epm}^{T}, C_{M}^{T}, C_{c}^{T}, C_{E}^{T}\right)$ considered in this work (Equations 3.5 and 3.6)

$$\hat{F}_{EX}^{C} = f\left(C_{Own}^{Tot}, C_{Epm}^{T}, C_{M}^{T}, C_{c}^{T}, C_{E}^{T}\right) \tag{3.5}$$

$$\hat{F}_{EX}^{C} = C_{Own}^{Tot} + C_{Epm}^{T} + C_{M}^{T} + C_{c}^{T} + C_{E}^{T} \tag{3.6}$$

Where the CAPEX elements relations were formulated based on the desired plant Greenfield and Brownfield design capacities and their respective cost per unit design capacities (Equations 3.7 – 3.11). It is worth noting that engineering and project management costs for Brownfields were considered negligible as it is expected that all significant CAPEX expenses had been catered for during their Greenfield development stages.

$$C_{Own}^{Tot} = G_{Dsgn}^{Cap} C_{GOwn}^{UCap} + B_{Dsgn}^{Cap} C_{BOwn}^{UCap} \tag{3.7}$$

$$C_{Epm}^{T} = G_{Dsgn}^{Cap} C_{GEpm}^{UCap} + B_{Dsgn}^{Cap} C_{BEpm}^{UCap} \tag{3.8}$$

$$C_{M}^{T} = G_{Dsgn}^{Cap} C_{GM}^{UCap} + B_{Dsgn}^{Cap} C_{BM}^{UCap} \tag{3.9}$$

$$C_{c}^{T} = G_{Dsgn}^{Cap} C_{GC}^{UCap} + B_{Dsgn}^{Cap} C_{BC}^{UCap} \tag{3.10}$$

$$C_{E}^{T} = G_{Dsgn}^{Cap} C_{GE}^{UCap} + B_{Dsgn}^{Cap} C_{BE}^{UCap} \tag{3.11}$$

The CAPEX fund inflow ($\dot{F}_{EX}^{C}$) and the OPEX fund inflow ($\dot{F}_{EX}^{O}$) are the amounts of funds invested into the purchase of all capital equipment and periodic operation of the LNG plant. $\dot{F}_{EX}^{C}$ was modelled as a function of the total and CAPEX already invested into the system, the original CAPEX intended to be invested into the system as well as the delay factors that inhibit CAPEX implementation (Equations 3.12 and 3.13). Due to its dependency on the funded budget, the $\dot{F}_{EX}^{O}$ on the other hand was formulated as a function of the product of the funds made available for OPEX, the fund availability factor and the fraction of the funds implemented (F_{IL}^{O}) [Equations 3.14 and 3.15).

$$\dot{F}_{EX}^{C} = f\left(\hat{F}_{EX}^{TC}, \hat{F}_{EX}^{C}, \omega_{EX}^{C}\right) \tag{3.12}$$

$$\dot{F}_{EX}^{C} = \begin{cases} \dfrac{\hat{F}_{EX}^{C}}{\omega_{EX}^{C}} & \left\{\hat{F}_{EX}^{TC} \leq 0, \omega_{EX}^{C} \geq 0\right\} \\ 0 & \{Otherwise\} \end{cases} \tag{3.13}$$

$$\dot{F}_{EX}^{O} = f\left(B^T, \dot{B}^T, \hat{F}_{EX}^{TC}, F_{IL}^{O}, \Omega_{EX}^{O}, t, t^*\right) \qquad (3.14)$$

$$\dot{F}_{EX}^{O} = \begin{cases} \dfrac{\left[\Omega\hat{F}\right]_{EX}^{O} F_{IL}^{O}}{\Omega_{EX}^{O}} & \left\{\hat{F}_{EX}^{TC} > 0, t = t^*, B^T \geq \left[\Omega\hat{F}\right]_{EX}^{O} F_{IL}^{O}\right\} \\ \dfrac{B^T F_{IL}^{O}}{\Omega_{EX}^{O}} & \left\{\hat{F}_{EX}^{TC} > 0, t = t^*, B^T < \left[\Omega\hat{F}\right]_{EX}^{O} F_{IL}^{O}\right\} \\ 0 & \{Otherwise\} \end{cases} \qquad (3.15)$$

Thus, equation 3.1 can be transformed into the form of equation 3.16 and used in the estimation of the B^T for the LNG project at any time (t) when all inputs for $\dot{B}^T, \dot{F}_{EX}^{C}$ and $\dot{F}_{EX}^{O}$ (accounted for in equations 3.2-3.15) have been defined.

$$\int_{B(t=0)}^{B(P_L)} dB^T = \int_{t=0}^{P_L} \dot{B}^T dt \qquad (3.16)$$

(2) Total OPEX fund

The total OPEX fund $\left(\hat{F}_{EX}^{TO}\right)$ accounts for all the funds available for OPEX at any given period. Its change of state at any time was determined as the difference between the inflow of OPEX funds and the sum of all OPEX disbursement rates for various activities related to equipment maintenance, feed gas and fuel gas purchases, labour expenses and miscellaneous expenses ($\dot{F}_i$) [Equations 3.17 and 3.18].

The $\dot{F}_i$ for the respective aforementioned activities is dependent on the availability of $\hat{F}_{EX}^{TO}$, the factors that necessitate the funding consideration for the activity (K_i^{FF}), the level of implementation of the allocated funds (K_i^{IL}) and the F_{IL}^{O} [Equations 3.18 and 3.19]. The disbursement of funds from $\hat{F}_{EX}^{TO}$ to fund the different OPEX activities (F_i) through $\dot{F}_i$ was designed to be made possible in the situation when F_i is less than a threshold value. This threshold value was formulated as the product of the periodic expenditure made on the activity $\left(\dot{E}_{xi}\right)$ and the fund access factor (f_{Fund}^{Access}) [Equation 3.19]

$$\frac{d\hat{F}_{EX}^{TO}}{dt} = \dot{F}_{EX}^{O} - \sum_{i=1}^{5} \dot{F}_i \qquad (3.17)$$

$$\dot{F}_i = f\left(\hat{F}_{EX}^{TO}, K_i^{FF}, K_i^{IL}, F_{IL}^{O}, \Omega_{EX}^{O}\right) \qquad (3.18)$$

$$\dot{F}_i = \hat{F}_{EX}^{TO} K_i^{FF} K_i^{IL} F_{IL}^{O} \Omega_{EX}^{O} \qquad \left\{\hat{F}_{EX}^{C} > 0;\ F_i \leq \dot{E}_{xi} f_{Fund}^{Access};\ \forall i\right\} \tag{3.19}$$

Thus, by substituting equation 3.19 into 3.17, $\hat{F}_{EX}^{TO}$ can be obtained from the closed-form integration of equation 3.20.

$$\int_{\hat{F}_{EX}^{TO}(t=0)}^{\hat{F}_{EX}^{TO}(T^*)} \left(\frac{d\hat{F}_{EX}^{TO}}{\dot{F}_{EX}^{O} - \sum_{i=1}^{6} \hat{F}_{EX}^{TO} K_i^{FF} K_i^{IL} F_{IL}^{O} \Omega_{EX}^{O}} \right) = \int_{t=0}^{T^*} dt \tag{3.20}$$

Where, $\{i = 1, 2, 3, 4, 5,6\}$ corresponds to {equipment maintenance, feed gas, fuel gas, labour, overhead and LNG shipping) respectively.

(3) OPEX funding for individual activities

The funding for the operational expenses involving activit**y** i $\{i = 1, 2, 3, 4, 5,6\}$ (F_i) represents the actual capital available and at the disposal for specific LNG operation activity i. F_i at any operation time was obtained as the difference between $\dot{F}_i$ and the rate of expenditure made concerning activity i ($\dot{E}_{xi}$) (Equations 3.21 and 3.22). For each activity, the $\dot{E}_{xi}$ was formulated as events that are dependent on the periodic cost of carrying out the activity (C_i^O), F_i and Ω_{EX}^{O} (Equation 3.23). Consideration was also given to scenarios involving leakages that take place during such activities. In that regard, the fund leakage factor (K_i^{FLF}) was also included as a parameter in the model. Equations 3.24 and 3.26 show the quantitative relationship for $\dot{E}_{xi}$, $\dot{U}_i$.

$$\frac{dF_i}{dt} = f\left(\dot{F}_i, \dot{E}_{xi}, \dot{U}_i\right) \tag{3.21}$$

$$\frac{dF_i}{dt} = \dot{F}_i - \dot{E}_{xi} - \dot{U}_i \tag{3.22}$$

$$\dot{E}_{xi} = f\left(C_i^O, K_i^{FLF}, F_i, \Omega_{EX}^{O}\right) \tag{3.23}$$

$$\dot{E}_{xi} = \begin{cases} C_i^O(1 + K_i^{FLF}) & \left\{F_i\Omega_{EX}^{O} \geq \left[C_i^O(1 + K_i^{FLF})\right]\right\} \\ F_i\Omega_{EX}^{O} & \{Otherwise\} \end{cases} \tag{3.24}$$

$$\dot{U}_i = f\left(F_i, K_i^U\right) \tag{3.25}$$

$$\dot{U}_i = K_i^U F_i \tag{3.26}$$

The fund available for any activity type i considered in this work was estimated using Equation 3.27. This relation was obtained by substituting equations 3.19 and 3.24 into 3.22.

$$\int_{F_{i(t=0)}}^{F_{i(T^*)}} \frac{dF_i}{(\hat{F}_{EX}^{TO} K_i^{FF} K_i^{IL} F_{IL}^{O} \Omega_{EX}^{O} - \dot{E}_i - K_i^{U} F_i\ )} = \int_{t=0}^{T^*} dt \tag{3.27}$$

(4) Total OPEX for individual activities

These are the outputs of the formulated SD model that tracks the total expenses spent on activity i at any time of operation t^* (Equation 3.28)

$$E_{xi}(t) = \left[\int_{\dot{E}_{xi}\{t=t^*\}}^{\dot{E}_{xi}\{t=T^*\}} \dot{E}_{xi} dt\right] - E_{xi}\{t^* = 0\} \tag{3.28}$$

It is worth noting that the OPEX quantities described in this section cover LNG liquefaction and delivery activities. To estimate OPEX for the liquefaction activity alone, the OPEX quantity that relates to shipping ($i = 6\ [Trpn]$) as it affects these equations will be removed.

3.7 Production operation sector model development

The LNG production operation involves processes utilised in the conversion of natural gas (NG) to the final product which is the LNG. The production operation sector model captures various activities that are involved in completing the process.

3.7.1 Context of the Production operation sector model

The production operation sector model was formulated based on some quantities identified as necessary for the various operations required for the feed gas to LNG conversion process (Table B2 in Appendix B). The context of this sector is described based on its subsectors which are the liquefaction operation sub-sector and the production personnel management sub-sector.

The context of the liquefaction operation sub-sector as described by the causal diagram in Figure 3.5 shows that once the CAPEX and funding for production operations have been met, customer orders are treated and production orders (POs) are made. Based on this, natural gas (NG) feed is transported into the plant where the production process of converting the NG into NLG is done. After liquefaction is completed, the produced LNG stored in tanks or reservoirs and when orders are released is loaded on ships/carriers for transportation to the buyers.

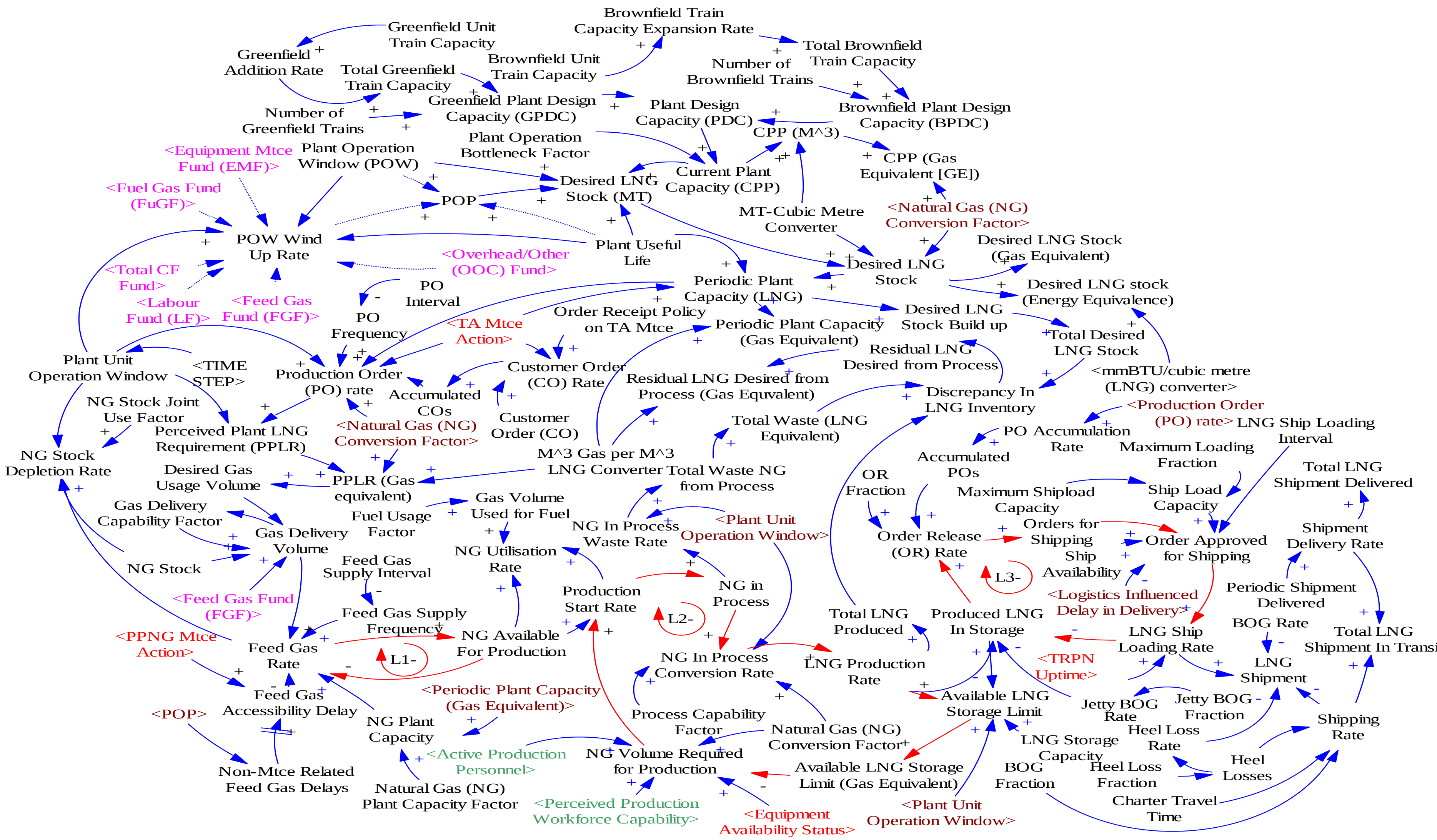

Figure 3.5: Causal diagram description of the LNG production operation sector

In this study, LNG is considered complete when the produced LNG is delivered to the buyer as is generally agreed upon in SPAs. The stock and flow model of this sub-sector (Figure 3.6) was developed based on this context.

The production personnel management sub-sector is concerned with the management of manpower for liquefaction activities. These activities include the determination of the production workforce's skill and capability, operators' workload, as well as personnel hiring and firing. The formulation of the models for the liquefaction operations and production personnel management sub-sectors are done in sections 3.7.2 and 3.7.3 respectively.

3.7.2 Development of liquefaction operation subsector stock and flow equations

Based on the context of the sector, a total of thirteen states were identified as playing an important role LNG liquefaction life cycle. The identified states are namely, the LNG operations window (t_{pw}), accumulated customer orders (COs) $[V_{order}^{cust}]$ for LNG, the total NG stock (V_{stock}^{NG}) NG available for production $\left(V_{Aprod}^{NG}\right)$, the NG in process $\left(V_{inproc}^{NG}\right)$, the total waste NG from the conversion process $\left(V_{inproc}^{NGw}\right)$, the produced LNG in storage $\left(V_{prod}^{LNG}\right)$, the total LNG produced $\left(V_{prod}^{TotLNG}\right)$, the accumulated production orders (POs) $[V_{Acc}^{PO}]$, the orders for shipping (V_{PO}^{ship}), the LNG shipment $\left(V_{LNG}^{ship}\right)$, the total LNG shipment in transit $\left(V_{Trnst}^{Ship}\right)$ and the total LNG shipment delivered $\left(V_{delvrd}^{Ship}\right)$. The stock and flow equation modelling for this sector's components carried out in this section and was based on these dynamic states.

(1) The Production Operations Window

The production operations window $\left(t_{pw}\right)$ refers to the period within which production activities take place. In the case of this study, it was considered as the period governing all operation activities from which the LCC of the system was estimated. It was assumed that t_{pw} became effective when all the purchases, equipment and funds necessary for the immediate start-up of operations have been made available. This means all required CAPEX $(\hat{F}_{EX}^{TC})$ based installations must have been made for the process to start.

Figure 3.6: Stock and flow diagram of the LNG production operation sector

In addition, it is also expected that the OPEX funds (F_i) for a single operational window must also be made available. Equations 3.29-3.33 describes this scenario.

$$\frac{d(t_{pw})}{dt} = f(\dot{t}_{pw}) \qquad (3.29)$$

$$\left(\hat{F}_{EX}^{TC}, F_i, t_{pw}^*, t_{pw}, P_L\right) \qquad (3.30)$$

$$\frac{d(t_{pw})}{dt} = t_{pw}^* \left\{\hat{F}_{EX}^{TC}, F_i, t_{pw}, P_L > 0\right\} \qquad (3.31)$$

$$\int_{P_L}^{t_{pw}} dt_{pw} = \int_{t=0}^{t} t_{pw}^* dt \qquad \left\{\hat{F}_{EX}^{TC}, F_i, t_{pw}, P_L > 0\right\} \qquad (3.32)$$

$$t_{pw} = P_L - t_{pw}^* t \qquad (3.33)$$

(2) The Accumulated Customer Orders

The accumulated COs (V_{order}^{cust}) describe the total orders received from the client in terms of LNG volume. A change in V_{order}^{cust} occurred based on the difference between the CO rate $\left(\dot{V}_{order}^{cust}\right)$ and the rate at which POs $\left(\dot{V}_{order}^{prod}\right)$ are made (Equations 3.34-3.35). $\dot{V}_{order}^{cust}$ and $\dot{V}_{order}^{prod}$ themselves are influenced by the respective periodic LNG quantity ordered for consumption (V_{order}^{co}) and those released for production $\left(V_{order}^{po}\right)$.

$$\frac{dV_{order}^{cust}}{dt} = f\left(\dot{V}_{order}^{cust}, \dot{V}_{order}^{prod}\right) \qquad (3.34)$$

$$\frac{dV_{order}^{cust}}{dt} = \dot{V}_{order}^{cust} - \dot{V}_{order}^{prod} \qquad (3.35)$$

The $\dot{V}_{order}^{cust}$ was formulated as the value of the periodic customer order(s) made (V_{order}^{co}). However, in accepting the customer's order, consideration was given to the scenario where a policy decision exists whether or not to accept customer orders while the plant is incapacitated due to turnaround maintenance action. Thus, $\dot{V}_{order}^{cust}$ was taken as V_{order}^{co} if the order receipt policy was accepted for all operational periods $\left(f_{Policy}^{OrdRct} = 1\right)$. Otherwise in scenarios of $f_{Policy}^{OrdRct} = 0$, then V_{order}^{co} was accepted only when there was no ongoing turnaround maintenance action in the system ($M^{TA} = 0$) [Equation 3.36].

$\dot{V}_{order}^{prod}$ on the other hand was formulated such that the total accumulated orders released for production within a period could not exceed the current capacity of the plant in that period 3.37

$$\dot{V}_{order}^{cust} = V_{order}^{co} \quad \left\{f_{Policy}^{OrdRct} = 1 \middle| f_{Policy}^{OrdRct} = 0; M^{TA} = 0\right\} \tag{3.36}$$

$$\dot{V}_{order}^{prod} = \begin{cases} P_{PC}K^{NGC} & \{V_{order}^{cust} > P_{PC}K^{NGC}|\} \\ V_{order}^{cust}K_F^{po} & \{V_{order}^{cust}K_F^{po} \leq V_{order}^{cust}t^{*-1}\} \\ V_{order}^{cust}t^{*-1} & \{Otherwise\} \end{cases} \tag{3.37}$$

P_{PC} in this study was formulated as a function of the plant's desired LNG stock (V_D^{LNG}) estimated for use during the plant's operational/study window (P_L), which translated to dividing V_D^{LNG} by P_LThe impact of the turnaround maintenance (M^{TA}) activities conducted on the plant was also considered such during these periods, the capacity for LNG production reduces to zero (Equations 3.38 and 3.39).

$$P_{PC} = f(V_D^{LNG}, P_L) \tag{3.38}$$

$$P_{PC} = \begin{cases} \frac{V_D^{LNG}}{P_L} & \{M^{TA} = 0|\} \\ 0 & \{Otherwise\} \end{cases} \tag{3.39}$$

It should be noted that equation 3.39 was formulated based on assumption 10 (section 3.5) where redundant operational policies are inexistent in the organisation. In that regard, the capacity for LNG production reduces to zero during turnaround maintenance actions.

(3) Total Natural Gas Stock

The total natural gas stock (V_{stock}^{NG}) is the amount of natural gas (NG) reserve available for utilisation. In this study, the change in the state of V_{stock}^{NG} which depicts its condition of depletion was considered to be affected by its rate of depletion $\left(\dot{V}_{stock}^{NG}\right)$ [Equation 3.40-3.41].

$$\frac{dV_{stock}^{NG}}{dt} = \dot{V}_{stock}^{NG} \tag{3.40}$$

$$\int_{V_{stock}^{NG}(t=0)}^{V_{stock}^{NG}(t)} dV_{stock}^{NG} = \int_{t=0}^{t} \dot{V}_{stock}^{NG}\, dt \tag{3.41}$$

$\dot{V}_{stock}^{NG}$ is influenced by the current NG stock state (V_{stock}^{NG}), feed gas rate $\left(\dot{V}_{Feed}^{NG}\right)$ acquired for LNG conversion and the NG stock joint use factor (K_{stock}^{NG}). K_{stock}^{NG} was included to reflect situations that may occur in which multiple plants share the same natural gas well/reserves. Equations 3.42-3.43 describe $\dot{V}_{stock}^{NG}$ and its dependencies.

$$\dot{V}_{stock}^{NG} = f\left(V_{stock}^{NG}, \dot{V}_{Feed}^{NG}, K_{stock}^{NG}, t_{pw}^{*}\right) \tag{3.42}$$

$$\dot{V}_{stock}^{NG} = \begin{cases} K_{stock}^{NG}\dot{V}_{Feed}^{NG} & \left\{K_{stock}^{NG}\dot{V}_{Feed}^{NG} \leq \frac{V_{stock}^{NG}}{t_{pw}^{*}}\right\} \\ \frac{V_{stock}^{NG}}{t_{pw}^{*}} & \{Otherwise\} \end{cases} \tag{3.43}$$

V_{stock}^{NG} can be obtained from the integration of Equation 3.41 after the necessary substitutions and initial boundary conditions are supplied.

(4) Natural Gas Available for Production

The change in state of natural gas volume available for LNG production $\left(\frac{dV_{Aprod}^{NG}}{dt}\right)$ was established to be dependent on the rate of feed NG supplied to the plant $\left(\dot{V}_{Feed}^{NG}\right)$ as well as the rate at which V_{Aprod}^{NG} is utilised for production $\left(\dot{V}_{used}^{NG}\right)$ [Equation 3.44-3.45].

$$\frac{dV_{Aprod}^{NG}}{dt} = f\left(\dot{V}_{Feed}^{NG}, \dot{V}_{used}^{NG}\right) \tag{3.44}$$

$$\int_{0}^{V_{Aprod}^{NG}(t)} dV_{Aprod}^{NG} = \int_{t=0}^{t} \left(\dot{V}_{Feed}^{NG} - \dot{V}_{used}^{NG}\right) dt \tag{3.45}$$

$\dot{V}_{Feed}^{NG}$ was determined to be influenced by the Gas Delivery Volume $\left(V_{Dd}^{LNGge}\right)$, the plant's NG capacity $\left(V_{pl\_max}^{NG}\right)$, the current V_{Aprod}^{NG} state, the delay encountered in accessing V_{Feed}^{NG} (D_{Feed}^{NG}), and the frequency of feed gas supply (f_{Feed}^{NG}) [Equations 3.46-3.47].

$$\dot{V}_{Feed}^{NG} = f\left(V_{Dd}^{LNGge}, V_{pl\_max}^{NG}, V_{Aprod}^{NG}, D_{Feed}^{NG}, f_{Feed}^{NG}\right) \tag{3.46}$$

$$\dot{V}_{Feed}^{NG} = \begin{cases} \left(V_{Dd}^{LNGge} f_{Feed}^{NG}\right) & \left\{(D_{Feed}^{NG} = 0) \wedge \psi \wedge \left(V_{Aprod}^{NG} f_{Feed}^{NG} < V_{pl\_max}^{NG} f_{Feed}^{NG}\right)\right\} \\ \frac{V_{Max}^{ship}}{t_{pw}^{*}} & \left\{(D_{Feed}^{NG} = 0) \wedge \tilde{\psi} \wedge \left(V_{Aprod}^{NG} f_{Feed}^{NG} < V_{pl\_max}^{NG} f_{Feed}^{NG}\right)\right\} \\ 0 & \left\{(D_{Feed}^{NG} = 0) \wedge \left(V_{Aprod}^{NG} f_{Feed}^{NG} \geq V_{pl\_max}^{NG} f_{Feed}^{NG}\right)\right\} \\ 0 & \{D_{Feed}^{NG} \neq 0\} \end{cases} \tag{3.47}$$

$$\psi \triangleq f_{Feed}^{NG}\left[V_{Dd}^{LNGge} + V_{Aprod}^{NG}\right] < f_{Feed}^{NG} V_{pl\_max}^{NG}$$

$$\tilde{\psi} \triangleq f_{Feed}^{NG}\left[V_{Dd}^{LNGge} + V_{Aprod}^{NG}\right] \geq f_{Feed}^{NG} V_{pl\_max}^{NG}$$

On the other hand, the rate of NG utilisation $\left(\dot{V}_{used}^{NG}\right)$ is affected only by the Production Start Rate (Equation 3.48).

$$\dot{V}_{used}^{NG} = \dot{V}_{start}^{LNG} \tag{3.48}$$

Thus, on the substitution of the input parameters in equations from equations 3.47 and 3.48 into Equation 3.45 and the subsequent integration of the latter, the relationship that describes V_{Aprod}^{NG} will be known. However, the parameters so far used to describe V_{Aprod}^{NG} are in their auxiliary forms. An analysis of the parameters to obtain them in their input state was further done and will be reported in a subsequent section.

(i) The Gas Delivery Volume

V_{Dd}^{LNGge} is the volume of feed gas that is required for periodic LNG production at the plant. It is modelled as a quantity that is decided upon by management and ordered after the desired gas usage volume $\left(V_{Du}^{LNGge}\right)$, the supply source V_{stock}^{NG}, the capacity to fund the supply (F_3) and the capability to ensure the delivery of the supply (K^{GD}) has been ascertained. V_{Dd}^{LNGge} is also dependent on the volume of natural gas desired by the plant for conversion activities (Equation 3.49-3.50)

$$V_{Dd}^{LNGge} = f\left(V_{Du}^{LNGge}, V_{stock}^{NG}, V_{Dd}^{LNGge}, K^{GD}, F_3\right) \tag{3.49}$$

$$V_{Dd}^{LNGge} = \begin{cases} K^{GD} V_{Du}^{LNGge} & \left\{V_{stock}^{NG} \geq K^{GD} V_{Du}^{LNGge}\right\} \\ K^{GD} V_{stock}^{NG} & \{Otherwise\} \end{cases} \tag{3.50}$$

The V_{Du}^{LNGge} volume is an important quantity. It describes the daily NG feed that is needed for periodic production activities. The NG equivalent of perceived plant LNG requirement (PPLR) (V^{PPLRge}) and the desired production start volume $\left(V_{Ds}^{LNGge}\right)$ were determined as the quantity's influence factors (Equation 3.51). The value of V_{Du}^{LNGge} was modelled to conform to two potential scenarios. The first involves a situation where the $V^{PPLRge} \leq$

V_{Ds}^{LNGge}, while the second scenario is the event in which $V^{PPLRge} > V_{Ds}^{LNGge}$. Equation 3.52 describes these situations.

$$V_{Du}^{LNGge} = f\left(V^{PPLRge}, V_{Ds}^{LNGge}, K^{NGC}\right) \quad (3.51)$$

$$V_{Du}^{LNGge} = \begin{cases} \frac{V^{PPLRge}}{K^{NGC}} & \left\{\frac{V^{PPLRge}}{K^{NGC}} \leq \frac{V_{Ds}^{LNGge}}{K^{NGC}}\right\} \\ \frac{V_{Ds}^{LNGge}}{K^{NGC}} & \left\{\frac{V^{PPLRge}}{K^{NGC}} > \frac{V_{Ds}^{LNGge}}{K^{NGC}}\right\} \\ 0 & \{Otherwise\} \end{cases} \quad (3.52)$$

Where $K^{NGC}(0 \leq K^{NGC} \leq 1)$ is the expected degree of conversion of NG to LNG and may arise due to many factors including process conditions and the quality of natural gas.

The V^{PPLRge} and V_{Ds}^{LNGge} are two quantities that provide production demand information depending on the conditions of the production status of the plant. Both of these quantities are influenced by several other components of the system. These are described next.

A. Equation Formulation for the Perceived Plant LNG Requirement

V^{PPLRge} was obtained as the PPLR (LNG equivalent) $[V^{PPLR}]$ and the LNG-NG conversion $[\beta]$ factor (IGU, 2020) [Equations 3.53 and 3.54].

$$V^{PPLRge} = \beta V^{PPLR} \quad (3.53)$$

$$\beta = 585 m^3 gas/m^3 LNG \quad (3.54)$$

Equation 3.55 describe V^{PPLR} as being dependent on the production order (PO) rate $\left(\dot{V}_{order}^{prod}\right)$, K^{NGC} and t_{pw}^{*}.

$$V^{PPLR} = \frac{\dot{V}_{order}^{prod} t_{pw}^{*}}{K^{NGC}} \quad (3.55)$$

$\dot{V}_{order}^{prod}$ is the rate at which various volumes of LNG are approved for production. It follows from the RHS of Equation 3.56 that,

$$\dot{V}_{order}^{prod} = \frac{V_{order}^{po}}{t^{po}} \quad (3.56)$$

Thus, on the substitution of Equation 3.56 into 3.55, V^{PPLR} is described by Equation 3.57.

$$V^{PPLR} = \frac{V^{po}_{order} t^{*}_{pw}}{K^{NGC} t^{po}} \quad (3.57)$$

B. Equation Formulation for the Desired Production Start Volume

The desired production start volume $\left(V^{LNGge}_{Ds}\right)$ is the amount of NG required to meet the overall expected production capability of the plant within any target time window. This implies that if production has not been begun in the chosen time interval of initial time t_0 and final time t_F $([t_F - t_0] \leq P_L)$, then

$$V^{LNGge}_{Ds}(t) = \begin{cases} V^{LNG}_{D} & \{t = t_0\} \\ 0 & \{t = t_F\} \end{cases} \quad (3.58)$$

From Figure 3.6, the conditions of V^{LNGge}_{Ds} are directly influenced by the information regarding the NG discrepancy in the production process (δ^{NG}). The natural gas discrepancy in the process was formulated as the difference between the residual NG Desired from the Production process $\left(V^{prodge}_{Res}\right)$ and the amount of NG currently undergoing conversion $\left(V^{NG}_{inproc}\right)$, [Equations 3.59-3.61].

$$V^{LNGge}_{Ds} = \delta^{NG} \quad (3.59)$$

$$\delta^{NG} = \begin{cases} V^{prodge}_{Res} - V^{NG}_{inproc} & \left\{\left(V^{prodge}_{Res} - V^{NG}_{inproc}\right) > 0\right\} \\ 0 & \{Otherwise\} \end{cases} \quad (3.60)$$

Where,

$$V^{prodge}_{Res} = \beta V^{prod}_{Res} \quad (3.61)$$

The Residual LNG Desired from Process $\left(V^{prod}_{Res}\right)$ which expresses the desire of management in terms of the process throughput was modelled as an outcome of the LNG balance in the plant's finished product inventory (δ^{LNG}) [Equations 3.62-.3.64]

$$V^{prod}_{Res} = \delta^{LNG} \quad (3.62)$$

$$\delta^{LNG} = \begin{cases} \left(V^{LNG}_{D} - \left[V^{ship}_{Order} + V^{w}_{inproc}\right]\right) & \left\{\left(V^{LNG}_{D} - \left[V^{ship}_{Order} + V^{w}_{inproc}\right]\right) \geq 0\right\} \\ 0 & \{Otherwise\} \end{cases} \quad (3.63)$$

Where,

$$V^{w}_{inproc} = V^{wge}_{inproc} \beta^{-1} \quad (3.64)$$

V_{Order}^{ship} and V_{inproc}^{wge} exist as states in the production operation sector and will be discussed later in this section. The auxiliary quantity, V_D^{LNG} represents an LNG production amount that has been estimated in the pre-production phase of the system. This estimate considers the total amount of LNG (in Million Tonne [MT]) desired within the Target production interval (V_D^{LNGMT}) and the expected fraction that may likely be produced as waste from the process. V_D^{LNG} was formulated as shown in Equation 3.65.

$$V_D^{LNG} = \frac{V_D^{LNGMT}\gamma}{K^{NGC}} \quad (3.65)$$

$$\gamma = 2.222 \times 10^6 \quad (3.66)$$

Where γ is the factor of conversion of MT to m^3 (International Gas Union [IGU], 2012).

As mentioned earlier, V_D^{LNGMT} is an estimate made to cater to the target plant operation period (POP) [t^*]. Other quantities which influence it are the t_{pw}, P_L and the current plant capacity (CPP) [P_{CC}]. Equation 3.67 describe the V_D^{LNGMT} formulation.

$$V_D^{LNGMT} = P_{CC}P_L \ \{t^* > 0 \ \wedge \ t_{pw} \leq P_L\} \quad (3.67)$$

The CPP (Equation 3.68) describes the effect of plant operation bottleneck factors (K_{OBN}^P) on the existing plant design capacity (P_{DC}). Bottlenecks could occur as a result of issues relating to feed gas transmission and other related supply chain logistics (Houwer, 2015; Petrovich *et al.*, 2017). Thus, in the study, K_{OBN}^P is utilised as the feed gas make-up factor to account for such perceived bottlenecks.

$$P_{CC} = K_{OBN}^P P_{DC} \quad (3.68)$$

The plant design capacity is described in terms of the number of Greenfield and Brownfield trains and their respective capacities (Equations 3.69-3.70).

$$P_{CC} = f\left(G_{Dsgn}^{Cap}, B_{Dsgn}^{Cap}\right) = f(f[N_{Tr}^G, V_{Tr}^G], f[N_{Tr}^B, V_{Tr}^B]) \quad (3.69)$$

$$P_{CC} = N_{Tr}^G V_{Tr}^G + N_{Tr}^B V_{Tr}^B \quad (3.70)$$

(5) Natural Gas in Process

The state of the amount of NG in the production process $\left(V_{inproc}^{NG}\right)$ can be altered by the Production Start Rate $\left(\dot{V}_{start}^{LNG}\right)$, the rate at which the process produces waste $\left(\dot{V}_{inproc}^{NGw}\right)$, and the amount of NG converted in process to LNG $\left(\dot{V}_{inproc}^{NGc}\right)$. The dynamic state of V_{inproc}^{NG} when these causal quantities are described in their input parameters and integrated (Equation 3.71-3.72).

$$\frac{dV_{inproc}^{NG}}{dt} = \dot{V}_{start}^{LNG} - \left(\dot{V}_{inproc}^{NGc} + \dot{V}_{inproc}^{NGw}\right) \tag{3.71}$$

$$\int_{V_{inproc}^{NG}(t^*=0)}^{V_{inproc}^{NG}(t^*)} dV_{inproc}^{NG} = \int_{t^*=0}^{t^*} \left[\dot{V}_{start}^{LNG} - \left(\dot{V}_{inproc}^{NGc} + \dot{V}_{inproc}^{NGw}\right)\right] dt^* \tag{3.72}$$

Where $\dot{V}_{start}^{LNG}$ describes the quantity of natural gas required for LNG production at every production cycle (Equation 3.73). This quantity can only be made available under the condition that the equipment required for processing the material is available. ($A_S^S = 1$). Otherwise, no production cycle can begin (Equation 3.74)

$$\dot{V}_{start}^{LNG} = f\left(V_{Aprod}^{NG}, V_{Rprod}^{NG}, A_S^S\right) \tag{3.73}$$

$$\dot{V}_{start}^{LNG} = \begin{cases} V_{Rprod}^{NG} & \left\{A_S^S = 1; V_{Aprod}^{NG} > V_{Rprod}^{NG}\right\} \\ V_{Aprod}^{NG} & \left\{A_S^S = 1; V_{Aprod}^{NG} \leq V_{Rprod}^{NG}\right\} \end{cases} \tag{3.74}$$

V_{Rprod}^{NG} is the amount of NG required for production for the plant operation period t^* and was modelled as a function of four quantities namely, the number of active production personnel (W_{Prod}^{Act}), the perceived workforce capability (K^{WC}), the NG equivalent of the produced Available LNG Storage Limit $\left(V_{SLim}^{LNGge}\right)$ and the K^{NGC} (Equations 3.75 and 3.76). The W_{Prod}^{Act}, K^{WC}, and A_S^S exist as inputs in this (production operation) sector and will be treated as such.

$$V_{Rprod}^{NG} = f\left(W_{Prod}^{Act}, K^{WC}, V_{SLim}^{LNGge}, K^{NGC}\right) \tag{3.75}$$

$$V_{Rprod}^{NG} = \begin{cases} \left(\frac{W_{Prod}^{Act} K^{WC}}{K^{NGC}}\right) & \left\{V_{SLim}^{LNGge} \geq \left(\frac{W_{Prod}^{Act} K^{WC}}{K^{NGC}}\right)\right\} \\ \left(\frac{V_{SLim}^{LNGge}}{K^{NGC}}\right) & \{Otherwise\} \end{cases} \tag{3.76}$$

Equation 3.76 describes the value of V_{Rprod}^{NG} under two scenarios. The first scenario is that in which already produced LNG has not reached nor exceeded its available storage limit, while the second involves a situation where the storage limit volume V_{SLim}^{LNGge}, is less than the LNG product that is required or the storage capacity is reached/exceeded.

The LNG storage limit V_{SLim}^{LNG}, which is the LNG equivalent of V_{SLim}^{LNGge} (Equation 3.77) is influenced by the plant's storage capacity $\left(V_{SCap}^{LNG}\right)$, $\dot{V}_{prod}^{LNG}$, V_{prod}^{LNG} and t_{pw}^{*} (Equation 3.78). The description of V_{SLim}^{LNG} in terms of its dependencies is shown in Equation 3.79

$$V_{SLim}^{LNGge} = \beta V_{SLim}^{LNG} \tag{3.77}$$

$$V_{SLim}^{LNG} = f\left(V_{SCap}^{LNG}, \dot{V}_{prod}^{LNG}, V_{prod}^{LNG}, t_{pw}^{*}\right) \tag{3.78}$$

$$V_{SLim}^{LNG} = V_{SCap}^{LNG} - \left(\left[\frac{\dot{V}_{prod}^{LNG}}{t_{pw}^{*}}\right] + V_{prod}^{LNG}\right) \tag{3.79}$$

Where

$$\dot{V}_{prod}^{LNG} = \dot{V}_{inproc}^{NGc}\beta^{-1} \tag{3.80}$$

The NG in-process conversion rate $\left(\dot{V}_{inproc}^{NGc}\right)$ is influenced by V_{inproc}^{NG}, K^{NGC}, and the plant productivity (K^{PrC}). Equation 3.81 subsequently describes $\dot{V}_{inproc}^{NGc}$.

$$\dot{V}_{inproc}^{NGc} = \frac{V_{inproc}^{NG} K^{NGC} K^{PrC}}{t_{pw}^{*}} \tag{3.81}$$

The NG in process waste rate $\left(\dot{V}_{inproc}^{NGw}\right)$ is influenced by V_{inproc}^{NG}, $\dot{V}_{inproc}^{NGc}$ and t_{pw}^{*}, Equations 3.82 and 3.83.

$$\dot{V}_{inproc}^{NGw} = f\left(V_{inproc}^{NG}, \dot{V}_{inproc}^{NGc}, t_{pw}^{*}\right) \tag{3.82}$$

$$\dot{V}_{inproc}^{NGw} = V_{inproc}^{NG} - \left[\frac{\dot{V}_{inproc}^{NGc}}{t_{pw}^{*}}\right] \tag{3.83}$$

On the substitution of $\dot{V}_{inproc}^{NGc}$ in Equation 3.81 into Equation 3.83, Equation 3.84 describes the process waste rate in terms of the NG in process alongside the other process-related factors.

$$\dot{V}_{inproc}^{NGw} = V_{inproc}^{NG}\left(1 - \left[\frac{K^{NGC}K^{PrC}}{\left[t_{pw}^{*}\right]^{2}}\right]\right) \qquad (3.84)$$

When equations 3.74, 3.81 and 3.84 are substituted into Equation 3.72, the resultant equation is a complex integral with no close-form solution that describes V_{inproc}^{NG}.

(6) Total Waste Natural Gas from the Process

The total process waste $\left(V_{inproc}^{wge}\right)$ refers to the amount (in $m^3 gas$) of NG waste that is produced in the plant during processing. The V_{inproc}^{wge} occurs as a function of the NG in process waste rate $\left(\dot{V}_{inproc}^{NGw}\right)$ [Equation 3.85). The $\dot{V}_{inproc}^{NGw}$ is influenced by V_{inproc}^{NG}, $\dot{V}_{inproc}^{NGc}$ and t_{pw}^{*}. Thus equation 3.86 describes V_{inproc}^{wge}.

$$\frac{dV_{inproc}^{wge}}{dt} = f\left(\dot{V}_{inproc}^{NGw}\right) \qquad (3.85)$$

$$\int_{V_{inproc}^{wge}(t^*=0)}^{V_{inproc}^{wge}(t^*)} dV_{inproc}^{wge} = \int_{t^*=0}^{t^*} V_{inproc}^{NG}\left(1 - \left[\frac{K^{NGC}K^{PrC}}{\left[t_{pw}^{*}\right]^{2}}\right]\right) dt^* \qquad (3.86)$$

(7) The produced LNG in storage

The produced LNG $\left(V_{prod}^{LNG}\right)$ is the amount of NG converted to the desired product. Its state value is influenced incoming LNG production rate $\left(\dot{V}_{prod}^{LNG}\right)$, and the out-going ship loading rate $\left(\dot{V}_{Load}^{ship}\right)$ and potential jetty BOG losses $\left(\dot{V}_{BOG}^{Jetty}\right)$ during loading (Equations 3.87 – 3.88).

$$\frac{dV_{prod}^{LNG}}{dt} = \dot{V}_{prod}^{LNG} - \dot{V}_{Load}^{ship} - \dot{V}_{BOG}^{Jetty} \qquad (3.87)$$

$$\int_{V_{prod}^{LNG}(t^*=0)}^{V_{prod}^{LNG}(t^*)} dV_{prod}^{LNG} = \int_{t^*=0}^{t^*} \left(\dot{V}_{prod}^{LNG} - \dot{V}_{Load}^{ship} - \dot{V}_{BOG}^{Jetty}\right) dt^* \qquad (3.88)$$

The ship loading rate is influenced by the transportation equipment availability (E_A^{TRPN}) and the order released for shipping $\left(\dot{V}_{Order}^{Rel}\right)$ [Equation 3.89], while $\dot{V}_{BOG}^{Jetty}$ is generally estimated as a factor $\left(f_{BOG}^{Jetty}\right)$ of V_{prod}^{LNG} (Equation 3.90).

$$\dot{V}_{Order}^{ship} = \begin{cases} \dot{V}_{Order}^{Rel} & \{E_A^{TRPN} = 1\} \\ 0 & \{Otherwise\} \end{cases} \tag{3.89}$$

$$\dot{V}_{BOG}^{Jetty} = f_{BOG}^{Jetty} V_{prod}^{LNG} \tag{3.90}$$

(8) Total LNG produced

The total LNG produced $\left(V_{prod}^{TotLNG}\right)$ is an output status of the system that provides information on the total amount of LNG produced from the initial plant start-up to the current period. It is the integration of $\dot{V}_{prod}^{LNG}$ (Equation 3.91).

$$V_{prodt^*}^{TotLNG} = \left(\int_{t=t^*}^{T^*} \dot{V}_{prod}^{LNG} dt\right) - V_{prodt^*=0}^{TotLNG} \tag{3.91}$$

(9) Accumulated Production Orders

The Accumulated POs (V_{Acc}^{PO}) was modelled as a volumetric expression of the accumulated amount of NG desired for conversion. This value was determined based on the PO accumulation rate $\left(\dot{V}_{Acc}^{PO}\right)$ and the OR rate $\left(\dot{V}_{OR}^{PO}\right)$. The former is the pile-up rate at which LNG products have been approved for production while the latter represents the rate at which produced LNG is released for shipping activities. Equation 3.92 describe these quantities and their dynamic interaction.

$$\frac{d(V_{Acc}^{PO})}{dt} = \dot{V}_{Acc}^{PO} - \dot{V}_{OR}^{PO} \tag{3.92}$$

$\dot{V}_{OR}^{PO}$ was determined to be influenced by V_{Acc}^{PO} , the periodic OR fraction $\left(K_{OR}^{delay}\right)$ which represents the periodic proportion of finished product that is released to meet the orders based on organisational decision, the current produced LNG in the inventory $\left(V_{prod}^{LNG}\right)$ and the unit operations window available for undertaking pre-shipment activities $\left(t_{pw}^*\right)$. The order release rate was subsequently determined using Equation 3.93.

$$\dot{V}_{OR}^{PO} = \begin{cases} K_{OR}^{delay} V_{Acc}^{PO} & \{K_{OR}^{delay} V_{Acc}^{PO} \leq V_{prod}^{LNG}\} \\ V_{Acc}^{PO} & \{Otherwise\} \end{cases} \tag{3.93}$$

Equation 3.93 describes two scenarios of the order release rate. The first refers to a situation where the LNG in the inventory is more than adequate to cater to all orders made. However, that order released becomes dependent on the decision by management whether to release all or parts of the order to meet customer demand. The second scenario captures situations that may occur in which the Accumulated POs exceed the produced LNG in the inventory. The relationship that describes V_{Acc}^{PO} was subsequently determined when Equation 3.93 and is substituted into Equation 3.92 and integrated.

(10) Orders for Shipping

Consideration for the LNG orders that are in preparation for shipping $\left(V_{PO}^{ship}\right)$ was made to capture the delays that frequently occur during the process of preparing the shipment for onward transportation to designated clients. The change in the state of V_{PO}^{ship} was formulated as the difference between the PO release rate $\left(\dot{V}_{OR}^{PO}\right)$ and the rate at which the released orders are approved for shipping $\left(\dot{V}_{App}^{Ship}\right)$. $\dot{V}_{App}^{Ship}$ is affected by the amount of LNG that a ship or carrier of capacity $\left(\mathrm{V}_{Load}^{Ship}\right)$ can accommodate if such a vessel is available $\left(\mathrm{E}_{Avail}^{Ship}\right)$ and the required amount for loading has been produced and is available in storage $\left(V_{prod}^{LNG}\right)$. It is also affected by the shipment preparation delay $\left(D_{Prep}^{ship}\right)$ and the time required for vessel loading completion $\left(t_{Load}^{ship}\right)$ [Equation 3.94]

$$\dot{V}_{App}^{Ship} = \frac{\mathrm{V}_{Load}^{Ship}}{t_{Load}^{ship}} \quad \left\{\mathrm{E}_{Avail}^{Ship} = 1; D_{Prep}^{ship} = D_{Prep}^{ship*}; V_{prod,}^{LNG} V_{PO}^{ship} \geq \left(\frac{\mathrm{V}_{Load}^{Ship}}{t_{Load}^{ship}}\right)\right\} \quad (3.94)$$

Where,

$$\mathrm{V}_{Load}^{Ship} = \mathrm{K}_{Load}^{Ship}\mathrm{V}_{Load}^{MaxShip} \quad (3.95)$$

The K_{Load}^{Ship} is the maximum percentage capacity of the vessel recommended for loading. The value of 98% is generally adopted for K_{Load}^{Ship}. $\mathrm{V}_{Load}^{MaxShip}$ is the vessel's maximum LNG carrying capacity.

The V_{PO}^{ship} was subsequently obtained using equation 3.96 on the substitution of appropriate values in equations 100 and 101 into the V_{PO}^{ship} state relationship.

$$\int_{V_{Prep}^{ship}(t^*=0)}^{V_{Prep}^{ship}(t^*)} dV_{PO}^{ship} = \int_{t^*=0}^{t^*} \left(\dot{V}_{OR}^{PO} - \dot{V}_{App}^{Ship}\right) dt^* \quad (3.96)$$

(11) LNG shipment

The LNG shipment $\left(V_{LNG}^{ship}\right)$ refers to the effective amount of LNG designated for shipping to a buyer. V_{LNG}^{ship} is the rate of LNG loaded on the ship less the losses that usually occur from shipment burn-off during carrier transit $\left(\dot{V}_{BOG}^{Trnst}\right)$ and heel allocation $\left(\dot{V}_{Loss}^{Heel}\right)$ as well as periodic LNG already shipped or in transit $\left(\dot{V}_{LNG}^{shipped}\right)$ [Equation 3.97].

$$dV_{LNG}^{ship} = \dot{V}_{Load}^{ship} - \left(\dot{V}_{Loss}^{Heel} + V_{LNG}^{shipped} + \dot{V}_{BOG}^{Trnst}\right) \tag{3.97}$$

Adopting Styliadis and Koliousis (2017) recommendation, a heel allocation of 5% fraction of $\dot{V}_{Load}^{ship}$ was adopted in estimating $\dot{V}_{Loss}^{Heel}$. It was assumed that heel allocations were necessary only for vessels that are embarking on their first LNG supply trip. Thus the trip frequency event signal $\left(\mathrm{E}_{Freq}^{Trip}\right)$ was created to provide this information during operation to allow for the required heel allocation. Equation 3.98 describes the relationship for estimating $\dot{V}_{Loss}^{Heel}$.

$$\dot{V}_{Loss}^{Heel} = \begin{cases} 0.05\dot{V}_{Load}^{ship} & \{\mathrm{E}_{Freq}^{Trip} = 1\} \\ 0 & \{Otherwise\} \end{cases} \tag{3.98}$$

$\dot{V}_{LNG}^{shipped}$ was estimated as the volume of $\dot{V}_{Load}^{ship}$ remaining after all expected losses have been deducted. As such, the quantity was formulated as being influenced by the BOG loss fraction f_{BOG}^{Trnst}, $\dot{V}_{Load}^{ship}$ and $\dot{V}_{Loss}^{Heel}$ and the roundtrip travel distance from the loading port to the destination port $\left(2t_{Trvl}^{Ship}\right)$. $\dot{V}_{LNG}^{shipped}$ and $\dot{V}_{BOG}^{Trnst}$ were estimated using equations 3.99 and 3.100 respectively.

$$\dot{V}_{LNG}^{shipped} = \left(\dot{V}_{Load}^{ship} - \dot{V}_{Loss}^{Heel}\right)[1 - 0.01 f_{BOG}^{Trnst}]^{2t_{Trvl}^{Ship}} \tag{3.99}$$

$$\dot{V}_{BOG}^{Trnst} = \dot{V}_{Load}^{ship} - \left(\dot{V}_{LNG}^{shipped} + \dot{V}_{Loss}^{Heel}\right) \tag{3.100}$$

The V_{LNG}^{ship} was subsequently obtained by the substitution of Equations 3.99 - 3.101 into 3.98 and integrating.

(12) Total LNG shipment in transit

The amount of LNG in transit is monitored by the state quantity called the total LNG shipment in transit $\left(V_{Trnst}^{Ship}\right)$. The V_{Trnst}^{Ship} was modelled as a non-mixing state made up of z

time packets of LNG shipments ($z: Z, \ldots, 3,2,1, z < t^*$) with the least and most current shipment packets being max (z) and min (z) respectively. Thus $V^{Ship}_{Trnstt^*}$ can be described as the sum of $\dot{V}^{shipped}_{LNGz}$ (Equation 3.101).

$$V^{Ship}_{Trnstt^*} = \sum_{z=1}^{Z} \dot{V}^{shipped}_{LNGz} \tag{3.101}$$

A change in V^{Ship}_{Trnst} was modeled as the difference between the shipping rate $\left(\dot{V}^{shipped}_{LNG}\right)$ and the shipment delivery rate $\left(\dot{V}^{Ship}_{delvd}\right)$ [Equation 3.102]. The latter quantity expresses the arrival of a $V^{Ship}_{Trnstt^*}$shipment packet as LNG delivery to the buyer and is valid when a shipment has reached its delivery destination $\left(\ddot{V}^{Ship}_{delvd}\right)$ [Equation 3.103]

$$\frac{dV^{Ship}_{Trnstt^*}}{dt} = \dot{V}^{shipped}_{LNGt^*} - \dot{V}^{Ship}_{delvdt^*} = \dot{V}^{shipped}_{LNGt^*} - \ddot{V}^{Ship}_{delvd} \tag{3.102}$$

$$\ddot{V}^{Ship}_{delvd} = \begin{cases} \dot{V}^{shipped}_{LNGmin(z)} & \{E^{Ship}_{delvd} = 1\} \\ 0 & \{Otherwise\} \end{cases} \tag{3.103}$$

E^{Ship}_{delvd} is the signal that provides information on the arrival of $\dot{V}^{shipped}_{LNGmin(z)}$.

(13) Total LNG shipment delivered

The final state in the production operation subsector is the total LNG shipment delivered $\left(V^{Ship}_{delvrd}\right)$. The V^{Ship}_{delvrd} was formulated as the integration of $\dot{V}^{Ship}_{delvdt^*}$ (Equation 3.104).

$$V^{Ship}_{delvrdt^*} = \left(\int_{t=t^*}^{T^*} \dot{V}^{Ship}_{delvdt^*} dt\right) \tag{3.104}$$

3.7.3 The production workforce management sub-sector

The production workforce management sub-sector is critical for the functioning of the production operation sector. It describes the process of liquefaction operation workload $\left(W^{Load}_{PExptd}\right)$ determination as well as the workforce expected and perceived capabilities $\left[\left(K^{WC}_{Exptd}\right)\right.$ and $\left.(K^{WC})\right]$ respectively based on some previously estimated work rate of the workers $\left(L_{prod}^{WRate}\right)$. It also provides information on the production personnel inflow $\left(\dot{W}_{prod}^{ActIn}\right)$ and outflow $\left(\dot{W}_{prod}^{ActOut}\right)$, and the number of production workforce (W_{Prod}^{Act}) at any time in the system. The interaction of the quantities of the subsector is described by the causal diagram in Figure 3.7 while its dynamic behaviour is graphically captured by the subsector's stock and flow diagram (Figure 3.8).

3.7.4 Production workforce management dynamic equation formulation

Three quantities namely, the active production personnel (W_{Prod}^{Act}), the inactive production personnel (W_{Prod}^{Inact}), and the production workforce for recruitment $\left(W_{prod}^{Rcrit}\right)$ were identified as stocks in the production workforce management system. The equation formulation for this subsector using its input quantities was done based on these three state quantities. In addition the constrained workforce for production (W_{Prod}^{Con}); an auxiliary quantity that plays a significant role in the production workforce planning process is also discussed.

(1) The active production personnel

The active production personnel (W_{Prod}^{Act}) describes the number of liquefaction process operators that have been assigned for production operation at any particular time within the operation window. A change in W_{Prod}^{Act} exists as the difference between the rate of active production personnel inflow $\left(\dot{W}_{prod}^{ActIn}\right)$ and the sum of active production personnel outflow $\left(\dot{W}_{prod}^{ActOut}\right)$ and firing $\left(\dot{W}_{PFire}^{Act}\right)$ [Equation 3.105].

$$\frac{dW_{Prod}^{Act}}{dt} = \dot{W}_{prod}^{ActIn} - \left(\dot{W}_{prod}^{ActOut} + \dot{W}_{PFire}^{Act}\right) \qquad (3.105)$$

The $\dot{W}_{prod}^{ActIn}$ refers to the rate at which previously unassigned production operators $\left(W_{prod}^{Inact}\right)$ are assigned to production functions in the plant. This scenario is made possible on the condition that all equipment are of a functional status $(A_S^S = 1)$ and either the workforce required in the current production period (W_{Prod}^{Con}) or from backlogs $\left(W_{Prod}^{BLog}\right)$ have been determined to be less than the total number of assigned and unassigned operators $\left(W_{prod}^{Tot}\right)$ in the plant (Equations 106 and 107).

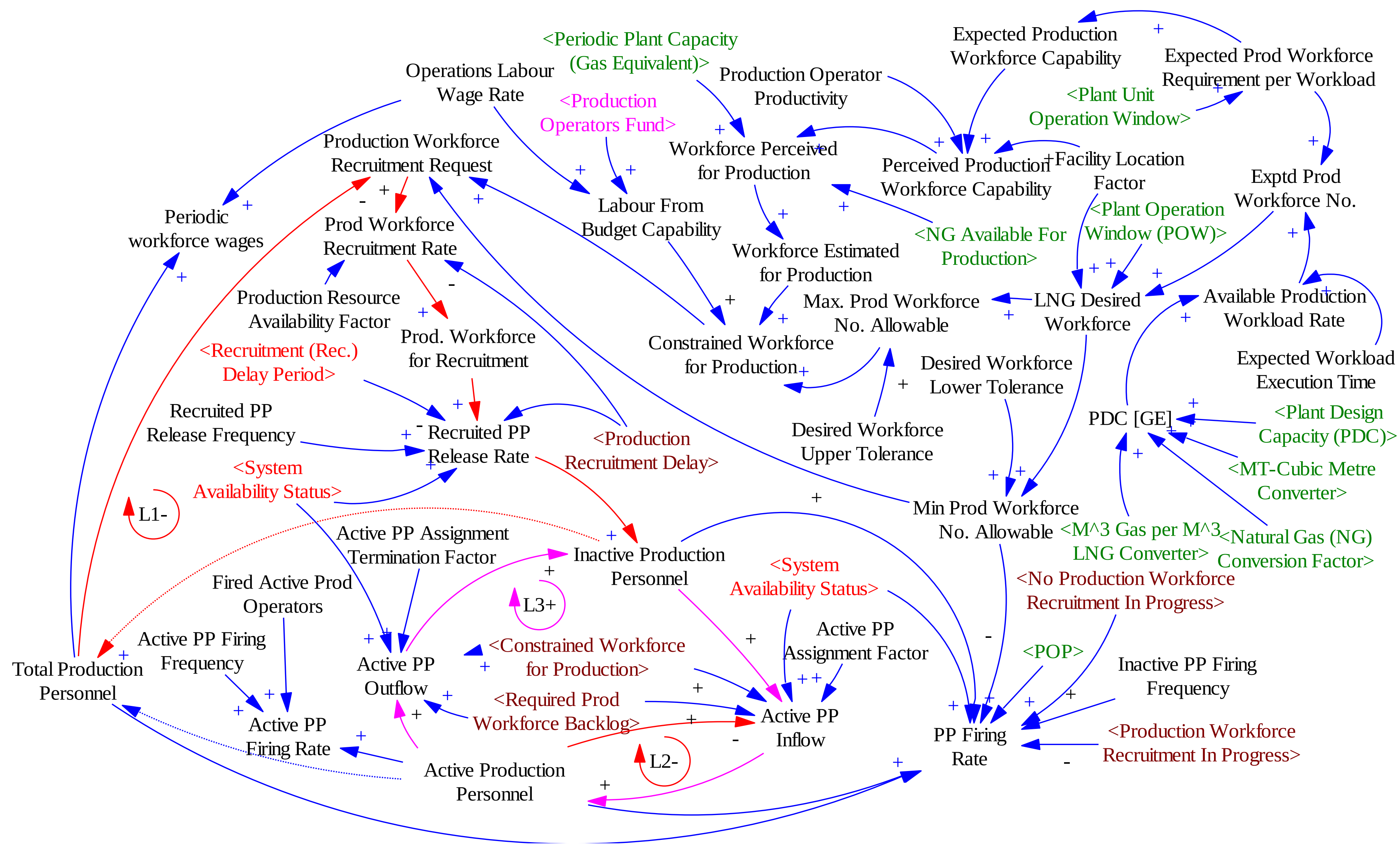

Figure 3.7: Causal diagram of the LNG production workforce management sub-sector

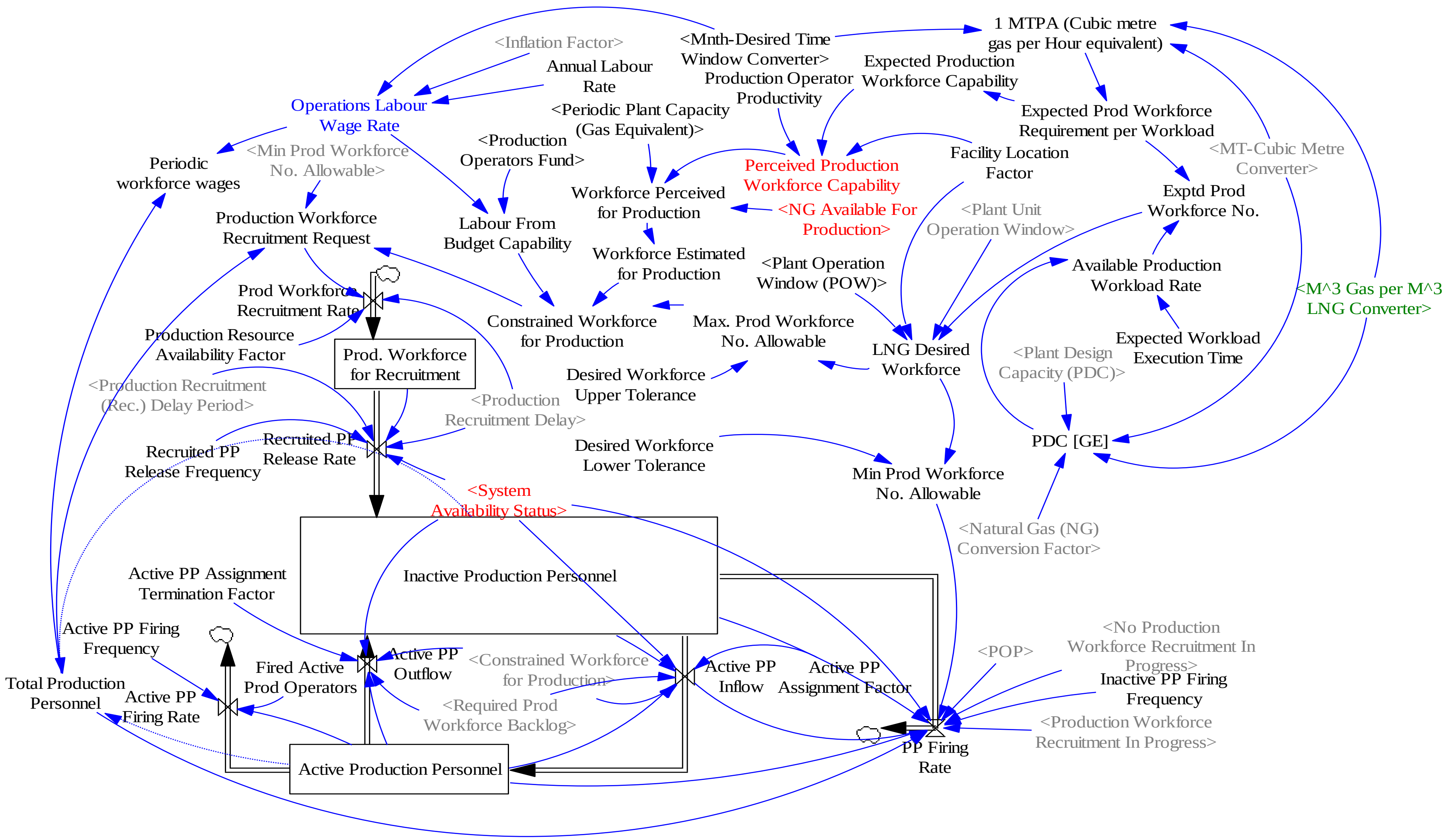

Figure 3.8: Stock and flow diagram of the LNG production workforce management sub-sector

$$\dot{W}_{prod}^{ActIn} = \begin{cases} \left(W_{Prod}^{*} - W_{Prod}^{Act} f_{PAsign}^{WAct}\right) & \left\{A_S^S = 1; \left(W_{Prod}^{*} - W_{Prod}^{Act} f_{PAsign}^{WAct}\right) \le W_{Prod}^{Inact} f_{PAsign}^{WAct}\right\} \\ W_{prod}^{Inact} f_{PAsign}^{WAct} & \left\{A_S^S = 1; \left(W_{Prod}^{*} - W_{Prod}^{Act} f_{PAsign}^{WAct}\right) > W_{Prod}^{Inact} f_{PAsign}^{WAct}\right\} \\ 0 & \{Otherwise\} \end{cases} \quad (3.106)$$

Where,

$$W_{Prod}^{*} = \begin{cases} W_{Prod}^{Con} & \left\{W_{Prod}^{BLog} = 0\right\} \\ W_{Prod}^{BLog} & \{Otherwise\} \end{cases} \quad (3.107)$$

Also, $\dot{W}_{prod}^{ActOut}$ describes the rate at which active production operators are relieved once their tasks have been completed. This scenario was modelled such that the active personnel for which task termination is desired are moved from the active personnel state to the inactive personnel state. To reduce the cost of hiring and firing as well as to reflect real systems' behaviour, consideration was made such that active operators were given top retainer priority whenever there were changes in operator requirements. In this regard, $\dot{W}_{prod}^{ActOut}$ outcome was based on the following stochastic conditions,

i. If the system is experiencing downtime at the instance of system malfunction or turnaround maintenance action, terminate all assigned tasks
ii. If the number of operators (whether current or from backlog) required for operation is lower than the number of active operators, then terminate assignments for the positive difference between the workforce requirement and the active operators.

Equation 3.108 describes this scenario and conditions.

$$\dot{W}_{prod}^{ActOut} = \begin{cases} W_{Prod}^{Act} f_{PTerm}^{WAct} & \left\{A_S^S = 0\right\} \\ W_{Prod}^{Act} f_{PTerm}^{WAct} - W_{Prod}^{*} & \{Otherwise\} \end{cases} \quad (3.108)$$

The $\dot{W}_{PFire}^{Act}$ captures scenarios during the production process where there may arise issues of worker firing that are unrelated to the regular assignment termination procedures (Equation 3.109).

$$\dot{W}_{PFire}^{Act} = W_{PFire}^{Act} f_{PFire}^{WAct} \quad (3.109)$$

(2) The Inactive production personnel

The state of the inactive production personnel is on that shows the number of unassigned operation workforce in the system at any time. A change in W_{Prod}^{Inact} is caused by the difference between the inflow of operators whose assignments have been terminated and the outflow of those that are just being assigned operational tasks. In addition, W_{Prod}^{Inact} is also affected by the difference between the production workforce recruitment rate $\left(\dot{W}_{prod}^{Rcrit}\right)$ and the rate at which unassigned operators are being fired $\left(\dot{W}_{prod}^{Fire}\right)$ [Equation 3.110].

$$W_{Prod}^{Inact} = \left(\dot{W}_{prod}^{Act\dot{O}ut} - \dot{W}_{prod}^{ActIn}\right) + \left(\dot{W}_{prod}^{Rcrit} - \dot{W}_{prod}^{Fire}\right) \tag{3.110}$$

There is usually a need for fresh workers recruitment, especially in situations where the total operating personnel in the liquefaction system is inadequate to cater for the manpower required for the LNG conversion process. Thus the need for $\dot{W}_{prod}^{Rcrit}$. $\dot{W}_{prod}^{Fire}$ reflects scenarios of termination of the work functions for some or all unassigned personnel and is usually triggered by certain conditions in a situation when the total number of production operators in the system $\left(W_{prod}^{Tot}\right)$ is larger than a certain minimum threshold decided by management $\left(W_{Prod}^{Min}\right)$, depending on the frequency in which the firing takes place $\left(f_{prod}^{WFire}\right)$. These conditions are outlined below.

1. When the system availability status is nonfunctional $W_{prod}^{Tot} - W_{Prod}^{Min}$ operators are released from the system.
2. When the system availability status is functional and there is no production workforce recruitment in progress $\left(f_{PProg}^{NRcrit} = 1\right)$, then all inactive operators are released provided all needed workforce have been assigned for required operations.

   These scenarios are described in equations 3.111-3.113.

$$\begin{cases} W_{prod}^{Tot} f_{prod}^{WFire} - W_{Prod}^{Min} & \{A_S^S = 0; \left(W_{prod}^{Tot} f_{prod}^{WFire} > W_{Prod}^{Min}\right)\} \\ W_{Prod}^{Inact} - \dot{W}_{prod}^{ActIn} - W_{Prod}^{Min} & \{A_S^S = 1; (B \geq C)\} \\ W_{Prod}^{Inact} f_{prod}^{WFire} - \dot{W}_{prod}^{ActIn} & \{A_S^S = 1; (B < C)\} \end{cases} \tag{3.111}$$

$$B = W_{prod}^{Tot} f_{prod}^{WFire} + \dot{W}_{prod}^{ActIn} \tag{3.112}$$

$$C = W_{Prod}^{Inact} - \dot{W}_{prod}^{ActIn} \tag{3.113}$$

(3) Production workforce recruitment

This state quantity caters to situations in which the existing total number of production operators is inadequate for the existing liquefaction operation workload. A change in the production workforce recruitment state is caused by the difference between the recruitment rate $\left(\dot{W}_{prod}^{Rcrit}\right)$ and the rate at which the recruited workforce is released $\left(\dot{W}_{prod}^{RcrRel}\right)$ into the plant (Equation 3.114).

The recruitment rate was derived as a product of the production workforce recruitment request $\left(W_{PRqst}^{Rcrit}\right)$ and the resource availability factor (f_{Prod}^{ResAv}). It was formulated to occur only in instances where no other recruitment exercises are ongoing $\left(t_{Prod}^{DRcrit} = 0\right)$ [Equation 3.115]. The W_{PRqst}^{Rcrit} was gotten as the positive personnel difference determined from the resource-constrained production workforce required (W_{Prod}^{Con}) and the total number of operators already existent in the plant (Equation 3.116). The f_{Prod}^{ResAv}on the other hand accounts for the degree to which the nature and characteristics of the workforce requested can be obtained. Characteristics that could influence the value of f_{Prod}^{ResAv} include factors such as skill level, experience and availability in the job market. A f_{Prod}^{ResAv} values of 0 and 1 imply total imperfect and perfect resource availability scenarios respectively.

$$\frac{dW_{prod}^{Rcrit}}{dt} = \dot{W}_{prod}^{Rcrit} - \dot{W}_{prod}^{RcrRel} \tag{3.114}$$

$$\dot{W}_{prod}^{Rcrit} = W_{PRqst}^{Rcrit} f_{Prod}^{ResAv} \qquad \left\{t_{Prod}^{DRcrit} = 0\right\} \tag{3.115}$$

$$W_{PRqst}^{Rcrit} = \begin{cases} W_{Prod}^{Con} - W_{prod}^{Tot} & \left\{W_{Prod}^{Con} - W_{prod}^{Tot} > 0\right\} \\ 0 & \{Otherwise\} \end{cases} \tag{3.116}$$

The rate at which the recruited workforce is released into the plant for liquefaction operation functions, $\dot{W}_{prod}^{RcrRel}$ is dependent on the availability of the required human resources, the recruitment completion delay period $\left(t_{Prod}^{DRcrit*}\right)$ and the frequency of the recruited workforce release $\left(f_{Prod}^{RcrRel}\right)$[Equation 3.117]. However, recruited personnel release can only take place as long as the system availability status is functional.

$$\dot{W}_{prod}^{RcrRel} = W_{prod}^{Rcrit} f_{Prod}^{RcrRel} \qquad \left\{A_S^S = 1; t_{Prod}^{DRcrit} = t_{Prod}^{DRcrit*}\right\} \tag{3.117}$$

(4) Constrained Workforce for Production

The constrained workforce for production is the quantity that describes the number of operation workforce that the system can cater for to be able to execute periodic NG -LNG conversion. Equation 3.118 describes W_{Prod}^{Con} to be the number of personnel approved to undertake liquefaction operations at any period based on the given workforce estimate (W_{Prod}^{Est}), the number of workers that can be catered for by management based on the funding limits available $\left(W_{Prod}^{BugCap}\right)$ and the upper workforce threshold policy of the organisation (W_{Prod}^{Max}).

$$W_{Prod}^{Con} = \begin{cases} W_{Prod}^{Est} & \{W_{Prod}^{Est} \leq W_{Prod}^{BugCap}, W_{Prod}^{Max}\} \\ W_{Prod}^{BugCap} & \{W_{Prod}^{Max} \leq W_{Prod}^{BugCap} > W_{Prod}^{Est}\} \\ W_{Prod}^{Max} & \{Otherwise\} \end{cases} \quad (3.118)$$

W_{Prod}^{BugCap} was determined to be influenced by the operations labour wage rate $\left(W_{Prod}^{Wage}\right)$ and the funds available to support the management of production manpower (B_{PP}) [Equation 3.119].

$$W_{Prod}^{BugCap} = \frac{B_{PP}}{W_{Prod}^{Wage}} \quad (3.119)$$

The workforce Estimated for production on the other hand is the number of production operators that are perceived as being needed to complete natural gas conversion tasks within a given period. W_{Prod}^{Est} was formulated in Equation 3.120 as a function of the periodic NG capacity of the plant $\left(P_{PC}^{ge}\right)$, the current NG volume available $\left(V_{Aprod}^{NG}\right)$, and the perceived workforce capability of the operators (K^{WC}).

$$\begin{cases} P_{PC}^{ge} {K^{WC}}^{-1} & \{P_{PC}^{ge} \leq V_{Aprod}^{NG}\} \\ V_{Aprod}^{NG} {K^{WC}}^{-1} & \{Otherwise\} \end{cases} \quad (3.120)$$

K^{WC} was formulated as the volume of natural gas that can be converted by an operator given the operator's estimated productivity (θ_{Prod}) and the facility location factor (f^{Loc}) [Equation 3.121]

$$K^{WC} = \frac{K_{Exptd}^{ProdWC} \theta_{Prod}}{f^{Loc}} \quad (3.121)$$

Where K_{Exptd}^{ProdWC} is the expected capability of the workers. K_{Exptd}^{ProdWC} was obtained as the inverse of the expected unit workforce required per unit workload $\left(W_{prod}^{UReqd}\right)$ as estimated by management (Equation 3.122).

$$K_{Exptd}^{ProdWC} = {W_{prod}^{UReqd}}^{-1} \quad (3.122)$$

It is worth noting that

$$\left(\dot{W}_{prod}^{ActOut}, \dot{W}_{prod}^{Actin}, W_{Prod}^{*}, \dot{W}_{prod}^{Rcrit}, \dot{W}_{prod}^{Fire}, W_{Prod}^{Min}, W_{Prod}^{Max}, W_{prod}^{Rcrit}; W_{Prod}^{Con}\right) \geq 0 \quad (3.123)$$

3.8 Maintenance sector development

The maintenance sector as modelled in this study takes into consideration the equipment required for the liquefaction process, the activities in terms of policies and actions necessary to preserve the equipment uptime and the interactions of the quantities within and outside the sector. Generally, it is focused on four subsectors namely equipment maintenance operation, human resource management, spares management and maintenance cost. This section is devoted to describing these subsectors in terms of their quantities, activities and interactions. All quantities that describe the interactions that lead to the functioning of this sector are defined in Table B3 of Appendix B.

3.8.1 Context of the maintenance sector model

The maintenance sector is primarily focused on the availability of the system for liquefaction operations (Figure 3.9) during its expected life (L_s). Thus the system's availability status (A_S^S) is directly affected by the system failure (Φ_s). For the system to be considered as failed within the plant's operating window $\left(t_{pw}^*\right)$, during the plant's useful life (P_L), then at least one of the various equipment [equipment type (k)] (E_k), should be experiencing downtime as a result of some failures or interventions in the form of planned or unplanned maintenance activities carried out by the maintenance personnel. The quality and quantity of these interventions invariably impact the cost of the maintenance of the system.

3.8.2 Equipment Maintenance operation subsector

The equipment maintenance (EM) operation subsector was modelled based on six major maintenance practices namely planned (preventive) maintenance [PM], corrective (Repair) maintenance [CM], turnaround maintenance [TA], replacement (equipment disposal) maintenance, spares management and human resource management. The sector description is thus; an equipment E_k, once purchased enters a period of operational service t_k^*. Every time E_k reaches a pre-defined level of usage (Time to PM $[t_k^{ToPM}]$), a PM pre-request (E_k^{PMPR}) is made. if such request is approved, E_k is taken off the plant to undergo preventive maintenance action (E_k^{PMA}) if spares are available (E_k^{CPSPA}).

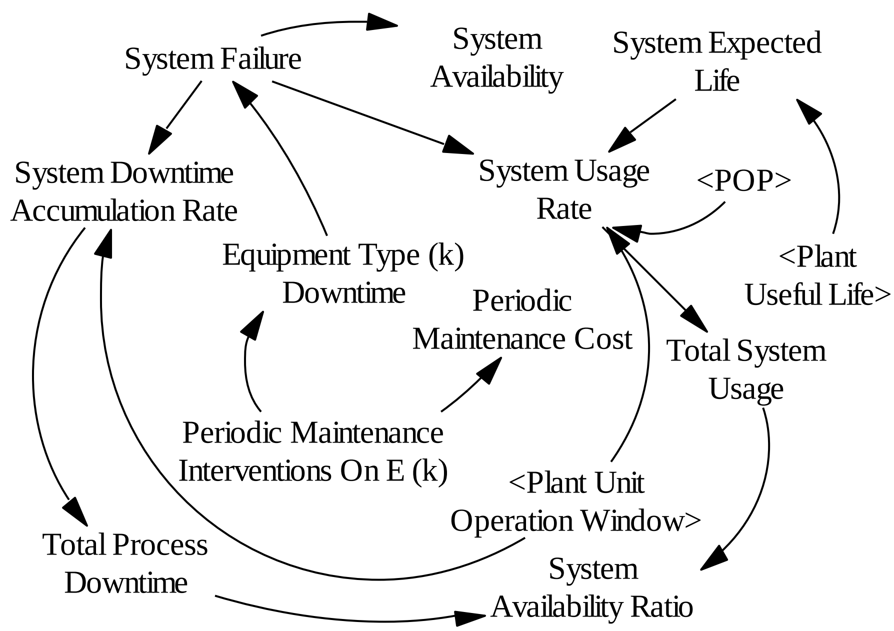

Figure 3.9: A Simplified concept of the SD-LNG-LCC maintenance system

After maintenance activities are completed, the equipment enters a renewed service period. Also, when a failure is detected before the PM request window (t_{Ek}^{PMRW}) is attained, the equipment is removed from the plant after a CM request $\left(E_{Ufk}^{WReq}\right)$ and the necessary repair actions or replaced through unplanned maintenance actions (E_k^{UAct}) are done by its maintenance personnel. For TA maintenance, when the equipment reaches a predefined long-term level of usage (TA maintenance time [t_{mtce}^{TA}]), the plant is shut down and TA maintenance action (E_k^{TAA}) for each E_k is conducted.

For each LNG production equipment type (E_k [k: 1,2,3, ..., K]), the quantities, their interactions and causal relationships are shown in Figure 3.10 while Figure 3.11 describes the stock and flow relationship of the quantities.

3.8.3 Stock and flow development of the equipment maintenance subsector

It can be observed from Figure 3.9 that for any $equipment, E_k$ was defined by six states namely, the degradation level (E_k^D), Maintenance process (E_{Prock}^{Mtce}), cumulative uptime (t_{cumk}^{Up}), and the cumulative downtime status (t_{cumk}^{Down}). The development of the flow equations that describe these states are discussed subsequently.

(1) The equipment degradation level

The equipment degradation level (E_k^D) is influenced by the Degradation Rate ($\dot{E}_k^D$) and the degradation reduction rate ($\dot{E}_k^{DR}$). Thus, the change in the state of E_k^D reflects the change in total system degradation brought about by operation and maintenance actions on E_k (Equations 124-128).

$$\frac{dE_k^D}{dt} = \dot{E}_k^D - \dot{E}_k^{DR} \tag{3.124}$$

$$\dot{E}_k^D = f\left(t^*, P_L, \Phi_S, t_{pw}^*\right) \tag{3.125}$$

$$\dot{E}_k^{DR} = f\left(E_k^D, t_{pw}^*, E_{Prock}^{Mtce}\right) \tag{3.126}$$

$$\dot{E}_k^D = t_{pw}^* \qquad \{t^* \le P_L;\ \Phi_S = 0\} \tag{3.127}$$

$$\dot{E}_k^{DR} = \frac{E_k^D}{t_{pw}^*} \qquad \{E_{Prock}^{Mtce} > 0\} \tag{3.128}$$

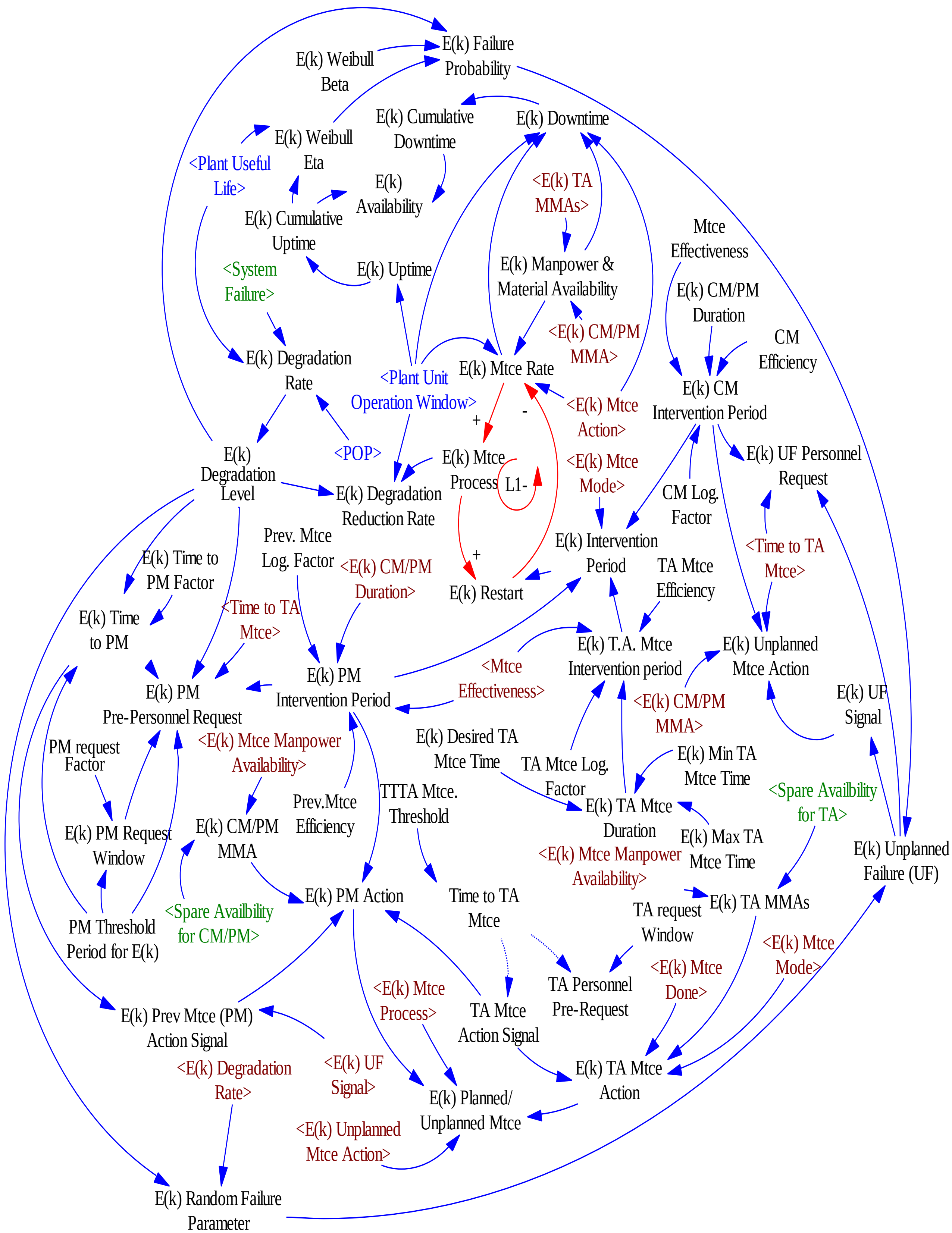

Figure 3.10: Causal diagram of the quantities affecting the maintenance operation

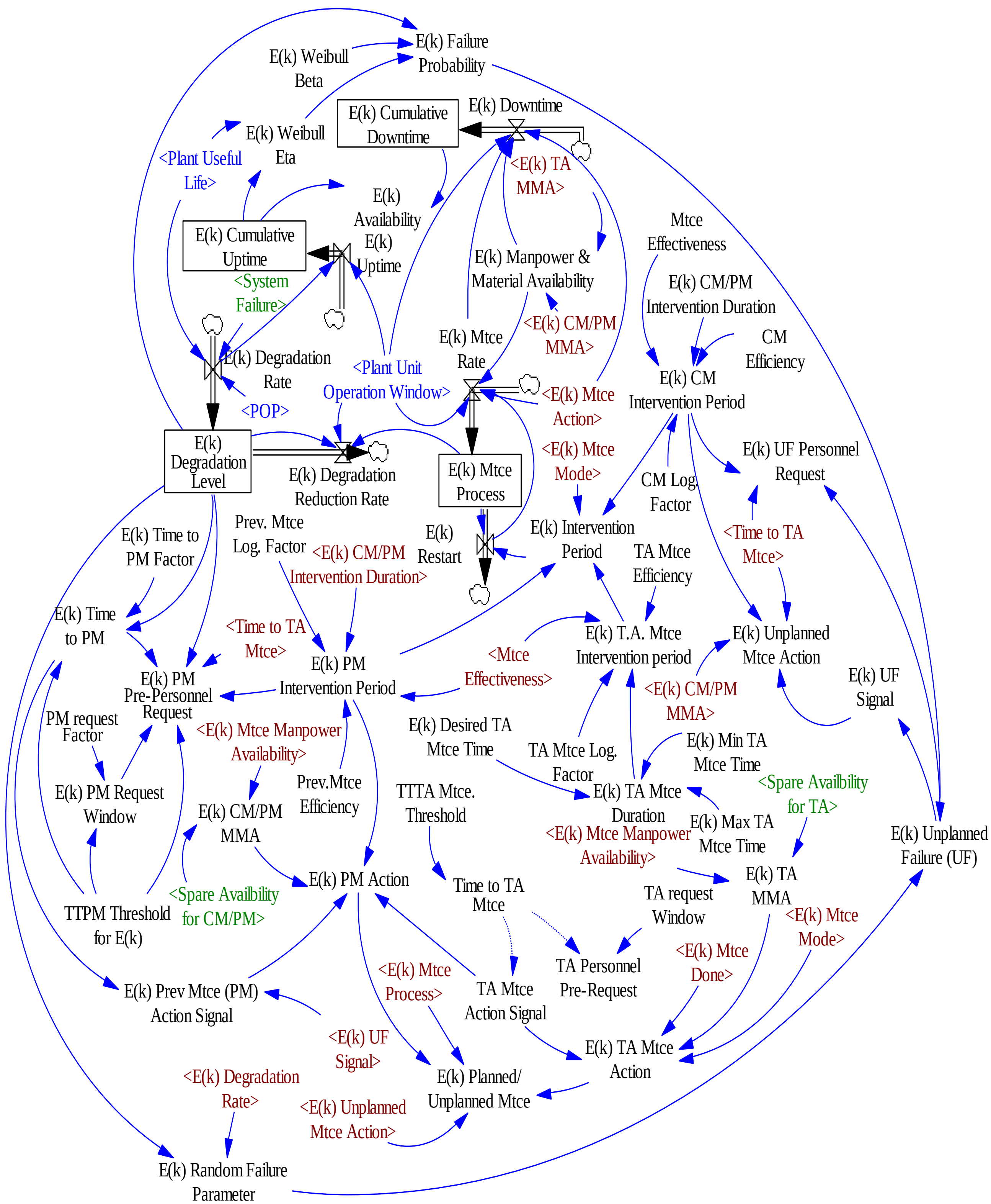

Figure 3.11: Stock and flow diagram of the quantities affecting the maintenance operation

This scenario was considered to exist when the failure status of the production system (Φ_S) is zero. In other words, the degradation level reflects the total usage time of E_k from its last maintenance action to the current period (Equation 3.129). Φ_S was modelled as having a status of failed ($\Phi_S = 1$) when at least one piece of equipment in the system was experiencing downtime or zero otherwise. (Equation 3.130).

$$\int_{E_k^D\{t=t^*\}}^{E_k^D\{T^*\}} \frac{dE_k^D}{\left(\dot{E}_k^D - \dot{E}_k^{DR}\right)} = \int_{t=t^*}^{T^*} dt \tag{3.129}$$

$$\Phi_S = \begin{cases} 1 & \left\{\exists \dot{E}_k^d = 1\right\} \\ 0 & \{Otherwise\} \end{cases} \tag{3.130}$$

(2) Maintenance Process

This state describes the interval within which an equipment degradation state is being either reduced or reversed. Mathematically in this study, the change in the maintenance process (E_{Prock}^{Mtce}) is modelled as a function of the maintenance rate ($\dot{E}_k^{Mtce}$) and the equipment restart rate ($\dot{E}_k^{Rsrt}$) [Equation 3.131]. E_{Prock}^{Mtce} was derived from the integration of the difference between $\dot{E}_k^{Mtce}$ and $\dot{E}_k^{Rsrt}$ (Equation 3.132). It can be seen from Equation 3.133 that $\dot{E}_k^{Mtce}$ is the value of the unit operation time of the plant when the workers and materials required for E_k are available and actual maintenance action is being undertaken ($E_{Mtcek}^{Act} = 1$).

The $\dot{E}_k^{Rsrt}$ serves as a sink for $\dot{E}_k^{Mtce}$ when the maintenance of E_k has been achieved and the equipment subsequently restarted for production operation (Equation 3.134).

The conditions that necessitate the occurrence of these situations were modelled as time-based signals in the system. They include the availability of maintenance workers and materials (E_k^{WMatAv}), maintenance action (E_{Mtcek}^{Act}) and maintenance intervention time for E_k (t_k^I). The quantitative formulation of these signals was done by adopting a dual (0, 1) status configuration for E_k^{WMatAv} and E_{Mtcek}^{Act}.

$$\frac{dE_{Prock}^{Mtce}}{dt} = f\left(\dot{E}_k^{Mtce}, \dot{E}_k^{Rsrt}\right) \tag{3.131}$$

$$\int_{E_{Prock}^{Mtce}\{t=t^*\}}^{E_{Prock}^{Mtce}\{T^*\}} E_{Prock}^{Mtce} = \int_{t=t^*}^{T^*} \left(\dot{E}_k^{Mtce} - \dot{E}_k^{Rsrt}\right) dt \tag{3.132}$$

$$\dot{E}_k^{Mtce} = \begin{cases} t_{pw}^{*} & \{E_k^{WMatAv} = 1; E_{Mtcek}^{Act} = 1; \dot{E}_k^{Rsrt} = 0\} \\ 0 & \{otherwise\} \end{cases} \tag{3.133}$$

$$\dot{E}_k^{Rsrt} = \begin{cases} \dot{E}_k^{Mtce} & \{\dot{E}_k^{Mtce} = t_k^I; \dot{E}_k^{Mtce}, t_k^I > 0\} \\ 0 & \{otherwise\} \end{cases} \tag{3.134}$$

Maintenance workers and materials were considered to be available once either the signals for CM/PM [E_{CmPmk}^{WMatAv}] or turnaround (TA) maintenance (E_{Tak}^{WMatAv}) indicates the availability of workers and materials for the maintenance strategy (Equation 3.135). Equations 136 and 137 show that these scenarios can only occur when the equipment spares and workers for the maintenance tasks for each policy are complete and available.

$$E_k^{WMatAv} = \max\left(E_{CmPmk}^{WMatAv}, E_{Tak}^{WMatAv}\right) \tag{3.135}$$

$$E_{CmPmk}^{WMatAv} = \begin{cases} 1 & \{E_{CmPm}^{SpAv} > 0; E_{Mtcek}^{WAv} = 1\} \\ 0 & \{otherwise\} \end{cases} \tag{3.136}$$

$$E_{Tak}^{WMatAv} = \begin{cases} 1 & \{E_{Ta}^{SpAv} > 0; E_{Mtcek}^{WAv} = 1\} \\ 0 & \{otherwise\} \end{cases} \tag{3.137}$$

Similarly, maintenance actions in the form of either turnaround (E_{Mtcek}^{TaAct}), preventive (E_{Mtcek}^{PmAct}), or corrective (E_{Mtcek}^{UAct}) for E_k are executed when the conditions for their occurrence are also triggered (Equations 138-144).

$$E_{Mtcek}^{Act} = max(A, B, C) \tag{3.138}$$

$$A = \begin{cases} 1 & \{E_{Mtcek}^{TaAct} = 1 \big| E_{Mtcek}^{Mode} = 1\ \{TA_{mode} = 1\}; E_{Sign}^{TaAct} = 1\} \\ 0 & \{otherwise\} \end{cases} \tag{3.139}$$

$$B = \begin{cases} 1 & \{E_{Mtcek}^{PMAct} = 1 \big| E_{Mtcek}^{Mode} = 2\ \{PM_{mode} = 1\}\} \\ 0 & \{otherwise\} \end{cases} \tag{3.140}$$

$$C = \begin{cases} 1 & \{E_{Mtcek}^{UAct} = 1 \big| E_{Mtcek}^{Mode} = 3\ \{CM_{mode} = 1\}\} \\ 0 & \{otherwise\} \end{cases} \tag{3.141}$$

$$E_{Mtcek}^{TaAct} = \begin{cases} 1 & \{E_{Sign}^{TaAct} = 1; TA_{mode} = 1; E_{Mtcek}^{Mode} \neq 1; E_{Tak}^{WMatAv} = 1; E_{Mtcek}^{Done} = 0\} \\ 0 & \{otherwise\} \end{cases} \tag{3.142}$$

$$E_{Mtcek}^{PMAct} = \begin{cases} 1 & \{E_{Signk}^{PmAct} = 1; E_{CMPmk}^{WMatAv} = 1; t_k^{ToTa} > t_k^{PmI}; t_k^{ToTa} > 0\} \\ 0 & \{otherwise\} \end{cases} \tag{3.143}$$

$$E_{Mtcek}^{UAct} = \begin{cases} 1 & \{E_k^{Uf} = 1 \big| E_{Signk}^{Uf} = 1; E_{CMPmk}^{WMatAv} = 1; t_k^{ToTa} > t_k^{CmI}; t_k^{ToTa} > 0\} \\ 0 & \{otherwise\} \end{cases} \tag{3.144}$$

The maintenance intervention period (t_k^I) which reflects the estimated time for completing a maintenance action was formulated as being dependent on the maintenance mode $\{E_{Mtcek}^{Mode}\}$ signaled to take place on the equipment (Equation 3.145). t_k^{ZI} for any policy type Z ($Z =$TA maintenance|PM|CM) was formulated as being defined when the estimated maintenance duration (t_{Durk}^{ZI}), logistics factor (f_{Ek}^{LogZ}) and the efficiency factor (f_{Ek}^{TechZ}), [Equations 146 and 147]. The t_{Durk}^{ZI} refers to a standard period in which maintenance action is expected to be completed on a piece of equipment. The logistics factor refers to issues such as the degree of access to maintenance equipment and spares, proximity to equipment location, etc., while f_{Ek}^{TechZ} depicts the maintenance workers' deviation from the expected maintenance period for E_k. Thus, maintenance on a piece of equipment was taken as being most efficient if $f_{Ek}^{TechZ} = 1$ factor is 1 and least efficient if $f_{Ek}^{TechZ} = 0$ (Equation 3.148).

$$t_k^I = \begin{cases} t_k^{TaI} & \{E_{Mtcek}^{Mode} = 1\} \\ t_k^{PmI} & \{E_{Mtcek}^{Mode} = 2\} \\ t_k^{CmI} & \{E_{Mtcek}^{Mode} = 3\} \end{cases} \tag{3.145}$$

$$t_k^{ZI} = f\left(t_{Durk}^{ZI}, f_{Ek}^{LogZ}, f_{Ek}^{TechZ}\right) \tag{3.146}$$

$$t_k^{ZI} = t_{Durk}^{ZI}\left(f_{Ek}^{LogZ} f_{Ek}^{TechZ}\right)^{-1} \tag{3.147}$$

$$0 \leq f_{Ek}^{LogZ}, f_{Ek}^{TechZ} \geq 1 \tag{3.148}$$

The TA maintenance signal (E_{Sign}^{TaAct}) as the name suggests reflects the quantity that monitors and signals the time for turnaround maintenance action when the situation is warranted. E_{Sign}^{TaAct} was formulated as a function of the time to TA maintenance (t_k^{ToTa}) [Equation 3.149]. t_k^{ToTa} was formulated as a memory register that informs the system when TA maintenance is due.

$$E_{Signk}^{TaAct} = \begin{cases} 1 & \{t_k^{ToTa} \leq 0\} \\ 0 & \{otherwise\} \end{cases} \tag{3.149}$$

Similarly, the preventive maintenance action signal (E_{Signk}^{PMAct}) was formulated to initiate when a certain time to PM (t_k^{ToPM}) is triggered barring any ongoing CM action (Equation 3.150). t_k^{ToPM} was modelled as being a function of the equipment degradation level of the (E_k^D) and an expected time to PM threshold (t_{TTPmk}^{Thr}) [Equation 3.151]. t_{TTPmk}^{Thr} is a system input and represents an organisational policy decision or the original equipment manufacturers' instructions on how long a piece of equipment should be allowed to operate before PM intervention is made.

$$E_{Signk}^{PMAct} = \begin{cases} 1 & \{t_k^{ToPM} \leq 0;\ E_{Signk}^{Uf} = 0\} \\ 0 & \{otherwise\} \end{cases} \tag{3.150}$$

$$t_k^{ToPM} = t_{TTPmk}^{Thr} - E_k^D \tag{3.151}$$

Also, the unplanned failure event signal (E_{Signk}^{Uf}) was designed to provide information regarding the failure state of E_k and stored in a memory bank. It serves as a signal that E_k requires corrective maintenance action (Equation 3.152). The unplanned failure event $\left(E_k^{Uf}\right)$ [Equation 3.153] captures the scenario where E_k experiences failure. This quantity was formulated based on the failure characteristics of E_k expressed in the form of its failure probability (P_{Ek}^{Φ}) [Equation 3.154]. P_{Ek}^{Φ} was formulated by the adoption of a two-parameter Weibull distribution model (Equation 3.135).

$$E_{Signk}^{Uf} = \begin{cases} 1 & \{E_k^{Uf} = 1\} \\ 0 & \{otherwise\} \end{cases} \tag{3.152}$$

$$E_k^{Uf} = P_{Ek}^{\Phi} \ \ \{P_{Ek}^{\Phi} \geq P_{Ek}^{\Phi r};\} \tag{3.153}$$

$$P_{Ek}^{\Phi} = 1 - e^{-\left(\frac{E_k^D}{\eta_{Ek}}\right)^{\beta_{Ek}}} \tag{3.154}$$

The $P_{Ek}^{\Phi r}$ is a randomly occurring value in the system with any value range between $P_{Ek}^{\Phi rL}$ and $P_{Ek}^{\Phi rH}$. The $P_{Ek}^{\Phi r}$ can be attributed to the value that captures the unpredictability of the system regarding sudden failure. However, the likelihood of the failure occurrence was considered to be most significant when the time of the usage-based condition of the equipment causes a probability of failure between $P_{Ek}^{\Phi rL}$ and $P_{Ek}^{\Phi rH}$. It is worth noting that defining these probability failure ranges is purely the concern of management. However, their proper definition would affect the decisions regarding when to undertake PM actions on E_k with a view to reducing unwanted failures.

(3) Cumulative uptime and cumulative downtime

The cumulative values of the uptime (t_{cumk}^{Up}) and downtime (t_{cumk}^{Down}) are output quantities that show the amount of time within the study period in which E_k has been operational and non-operational respectively. The t_{cumk}^{Up} was determined as the integral of the periodic uptime ($\dot{t}_{cumk}^{Up}$) of E_k (Equations 155). The $\dot{t}_{cumk}^{Up}$ represents the periodic deterioration of E_k (Equation 3.156). Similarly, t_{cumk}^{Down} was obtained from the integration of $\dot{t}_{cumk}^{Down}$ (Equations 157-158)

$$\int_{t_{cumk}^{Up}\{t=t^*\}}^{t_{cumk}^{Up}\{T^*\}} dt_{cumk}^{Up} = \int_{t=t^*}^{T^*} \dot{t}_k^{Up} dt \tag{3.155}$$

$$\dot{t}_k^{Up} = \dot{E}_k^D \tag{3.156}$$

$$\int_{t_{cumk}^{Up}\{t=t^*\}}^{t_{cumk}^{Up}\{T^*\}} dt_{cumk}^{Down} = \int_{t=t^*}^{T^*} \dot{t}_k^{Down} dt \tag{3.157}$$

$$\dot{t}_k^{Down} = \begin{cases} t_{pw}^* & \{\dot{E}_k^{Mtce} | E_k^{Uf} | E_{Mtcek}^{Act} = 1\} \\ 0 & \{otherwise\} \end{cases} \tag{3.158}$$

It is worth noting here that the context of maintenance policy formulation of the SD-LNG-LCC model follows that if an unplanned failure occurs to E_k in the system, priority is given to the repair of the equipment via corrective maintenance. Regarding planned maintenance (PM and TA maintenance) policies, maintenance is done when the degradation level of the equipment (E_k^D) reaches an expected threshold PM ($t_{TT\psi k}^{Thr}$) $\{\psi = Pm|Ta\}$. $t_{TT\psi k}^{Thr}$ is a system input and represents an organisational policy decision or the original equipment manufacturers' instructions on how long a piece of equipment should be allowed to work before planned maintenance intervention.

3.8.4 The human resource management for the maintenance function

The human resource management sub-sector was modelled to cater to manpower planning for the maintenance of equipment used in LNG processes. To this end, the context of the sub-sector follows that when there is a corrective, preventive, or turnaround maintenance need for any equipment E_k, the number of workers expected to carry out the task is first determined and a maintenance workers/labour request is triggered. Based on this, the system determines if there are unassigned maintenance personnel in the system that are qualified to undertake the task(s).

If such personnel exist, they are immediately assigned to the maintenance E_k for a pre-determined maintenance duration that is dependent on the nature of the equipment prevention, fault or failure. However, if the desired skill and number of personnel cannot be found in the system, then the system proceeds to recruit the required personnel.

The totality of the maintenance personnel in the system comprises regular and non-regular workers. The former refers to the number of maintenance personnel that is considered by management as being adequate for the generality of maintenance tasks. This number is modelled in this study as a value that exists between the maximum and minimum maintenance workforce allowable ($W_{Mtce}^{Min}, W_{Mtce}^{Max}$). However, in situations where the regular maintenance personnel is not adequate for the required maintenance action, the non-regular personnel are recruited only for the period for which there are required as they are subsequently retrenched at the end of such activities.

All maintenance actions and activities are dependent on the availability of resources in terms of spares, manpower and funding. The causal relationship of this subsector is described in Figure 3.12.

3.8.5 Stock and flow development of the maintenance-based human resource management subsector

The mathematical equations that characterise the behaviour of the maintenance-based human resource management subsector were formulated from the stock and flow diagram of the subsystem (Figure 3.13) based on five states namely, Workforce required CM/PM maintenance (W_{CmPmk}^{Rqrd}), Workforce required turnaround maintenance (W_{Tak}^{Rqrd}), active maintenance workers (W_{mtcek}^{Act}), Inactive maintenance workers (W_{mtce}^{Inact}) and workforce for maintenance recruitment (W_S^{Rcrit}). These quantities are subsequently discussed.

(1) Workforce required corrective and preventive maintenance

The change in the number of workers required for corrective or preventive maintenance action on E_k at any operation time t^* [dW_{CmPmk}^{Rqrd}] was formulated as the difference between the maintenance workforce required ($\dot{W}_{CmPmk}^{Rqrd}$) and those that have been met ($\dot{W}_{CmPmk}^{Met}$) for the equipment within any operation interval considered (Equation 3.159).

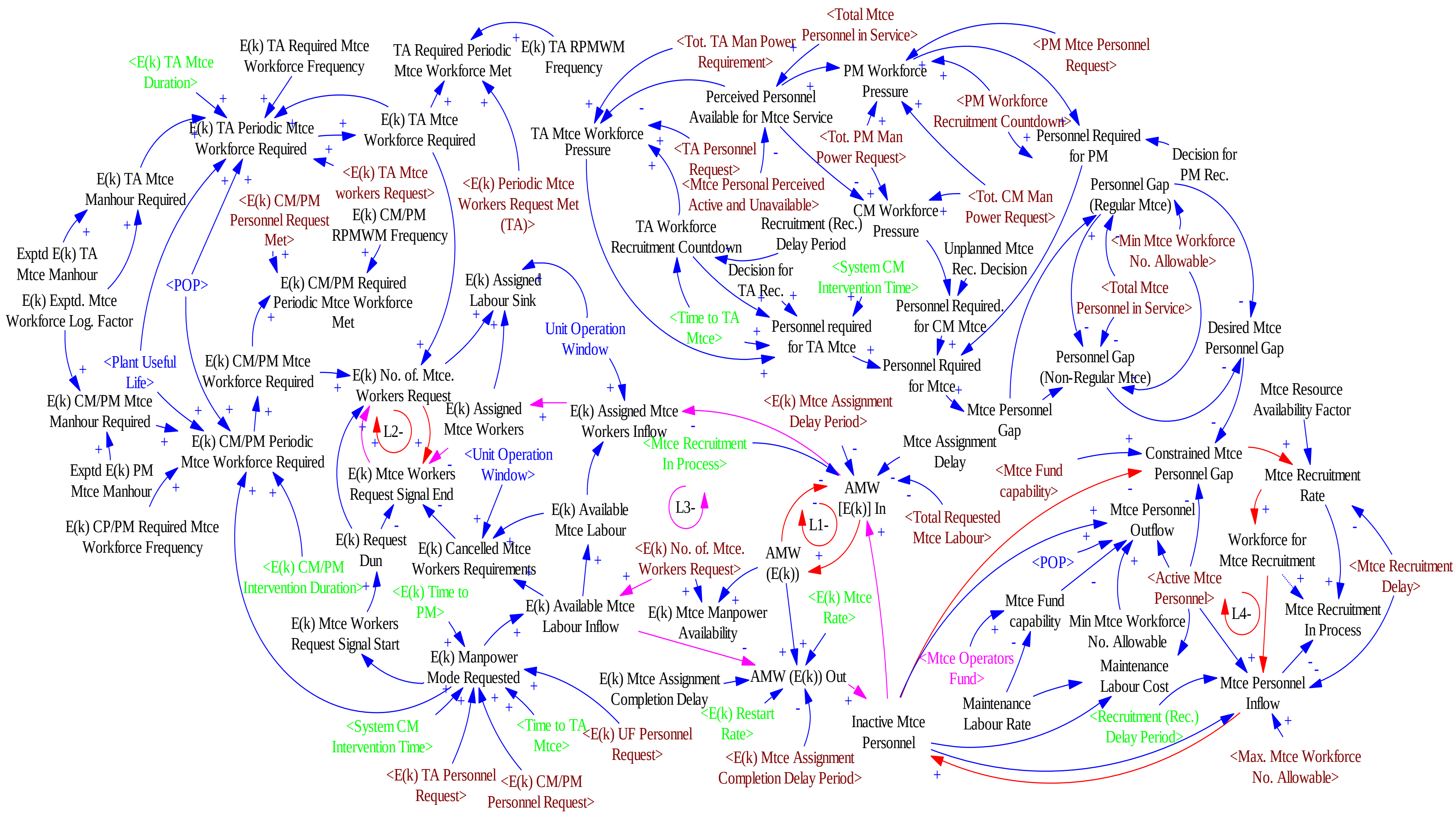

Figure 3.12: Causal diagram of the human resource management for the maintenance sector

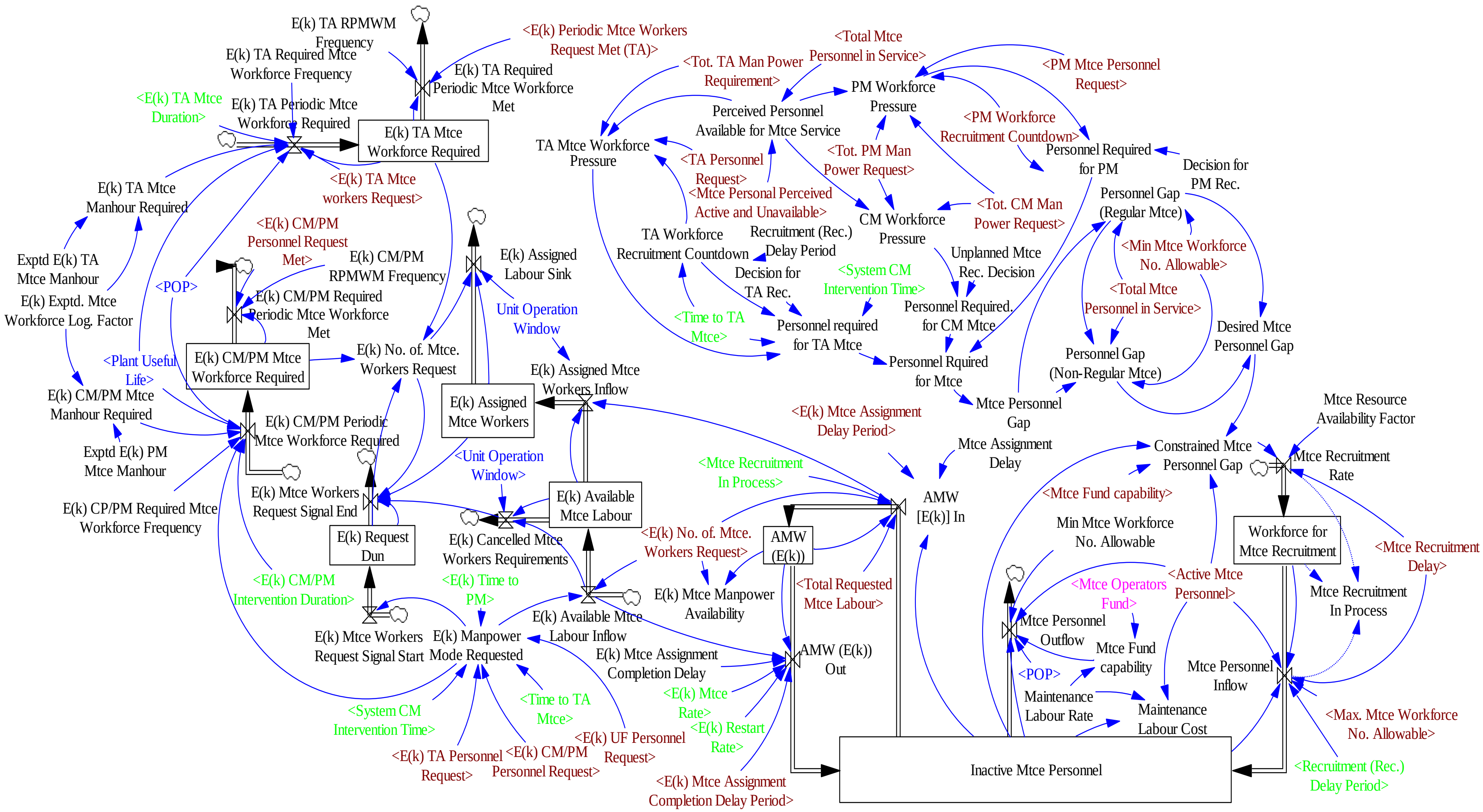

Figure 3.13: Stock and flow diagram of the human resource management for the maintenance sector

$$\frac{dW_{CmPmk}^{\dot{Rqrd}}}{dt} = \dot{W}_{CmPmk}^{Rqrd} - \dot{W}_{CmPmk}^{Met} \quad (3.159)$$

$\dot{W}_{CmPmk}^{Rqrd}$ value was obtained when the man-hour (t_{CmPmk}^{WRqrd}) and Duration required for maintaining E_k as well as the frequency at which the manpower is required (f_{CmPmk}^{WRqrd}) are defined (Equation 3.160). Similarly, $\dot{W}_{CmPmk}^{Met}$ was obtained as the product of W_{CmPmk}^{Rqrd} and the frequency at which workforce requirements are met (f_{CmPmk}^{WMet}) [Equation 3.161].

$$\dot{W}_{CmPmk}^{Rqrd} = \frac{t_{CmPmk}^{WRqrd} f_{CmPmk}^{WRqrd}}{t_{CmPmk}^{IDur}} \qquad \{t^* > 0; t^* \leq P_L; E_{Modek}^{WReq} = 2|3\} \quad (3.160)$$

$$\dot{W}_{CmPmk}^{Met} = W_{CmPmk}^{Rqrd} f_{CmPmk}^{WMet} \qquad \{E_{CmPmk}^{MetRqst} = 1\} \quad (3.161)$$

(2) Workforce required turnaround maintenance

In a similar manner to how W_{CmPmk}^{Rqrd} was formulated, the change in the required workforce for TA maintenance (dW_{Tak}^{Rqrd}) of equipment E_k was formulated as the difference between the periodic Maintenance Workforce Required ($\dot{W}_{Tak}^{Rqrd}$) and the periodic maintenance workforce requirement Met ($\dot{W}_{Tak}^{Met}$) [Equation 3.162]. $\dot{W}_{Tak}^{Rqrd}$ and $\dot{W}_{Tak}^{Met}$ were also formulated (Equations 163-164) in a similar way to equations 160 and 161.

$$\frac{dW_{Tak}^{\dot{Rqrd}}}{dt} = \dot{W}_{Tak}^{Rqrd} - \dot{W}_{Tak}^{Met} \quad (3.162)$$

$$\dot{W}_{Tak}^{Rqrd} = \frac{t_{Tak}^{WRqrd} f_{Tak}^{WRqrd}}{t_{Tak}^{IDur}} \qquad \{t^* > 0; t^* \leq P_L; E_{Tak}^{Rqst} = 1\} \quad (3.163)$$

$$\dot{W}_{Tak}^{Met} = W_{Tak}^{Rqrd} f_{Tak}^{WMet} \qquad \{E_{Tak}^{MetRqst} = 1\} \quad (3.164)$$

In order to capture information on the state of workforce requirement for E_k with respect to all forms of maintenance strategies adopted for managing the liquefaction plant, W_{CmPmk}^{Rqrd} and W_{Tak}^{Rqrd} were incorporated into an output quantity called the number of maintenance workers request $\left(W_{Mtcek}^{Rqst}\right)$ [Equation 3.165].

$$W_{Mtcek}^{Rqst} = \begin{cases} W_{CmPmk}^{Rqrd} & \{E_{Dunk}^{WRqst} = 2|3\} \\ W_{Tak}^{Rqrd} & \{E_{Dunk}^{WRqst} = 1\} \end{cases} \quad (3.165)$$

Where the request dun (E_{Dunk}^{WRqst}) represents a memory register that informs the system on about the status of the workforce requirement as for as long as the requirements have not been satisfied (Equations 166 - 168). Requests for maintenance workers for E_k begins with the maintenance Workers Request Signal Start $\left(\dot{E}_{DStrtk}^{WRqst}\right)$. Under specific conditions (Equations 167 - 168), $\dot{E}_{DStrtk}^{WRqst}$ may assume a coded value between 1 and 3 depending on the maintenance strategy desired. E_{Dunk}^{WRqst} assumes the value of $\dot{E}_{DStrtk}^{WRqst}$ until the requested maintenance workforce for the equipment (W_{Mtcek}^{Rqst}) has been assigned. Once this assignment is completed, the maintenance Workers Request Signal end $\left(\dot{E}_{DEndk}^{WRqst}\right)$ is activated to deactivate E_{Dunk}^{WRqst} (Equations 169 - 175).

$$E_{Dunk}^{WRqst} = \int_{t=t^*\left\{\dot{W}_{CmPmk}^{Rqrd}\middle|\dot{W}_{Tak}^{Rqrd}\right\}}^{t^*\left\{\dot{W}_{CmPmk}^{Met}\middle|\dot{W}_{Tak}^{Met}\right\}} \left(\dot{E}_{DStrtk}^{WRqst} - \dot{E}_{DEndk}^{WRqst}\right) dt \qquad (3.166)$$

$$\dot{E}_{DStrtk}^{WRqst} = E_{Modek}^{WRqst} \qquad (3.167)$$

$$E_{Modek}^{WRqst} = \begin{cases} 1 & \left\{E_{Tak}^{WRqst} = 1; t_k^{ToTa} = t_k^{ToTa*} \middle| \exists E_{Dunk}^{WRqst} = 1; Max(t_k^{CmI}) \geq t_k^{ToTa*}\right\} \\ 2 & \left\{E_{CmPmk}^{WRqst} = 1; t_k^{ToPm} = t_k^{Pm*}\right\} \\ 3 & \left\{E_{Dunk}^{WRqst} = 1\right\} \end{cases} \qquad (3.168)$$

$$\dot{E}_{DEndk}^{WRqst} = E_{Dunk}^{WRqst} \qquad \left\{W_{Mtcek}^{Ass} \geq W_{Mtcek}^{Rqst} \middle| \dot{W}_{Cank}^{Rqrd} > 0\right\} \qquad (3.169)$$

$$W_{Mtcek}^{Ass} = \int_{t=t^*\left\{\dot{W}_{CmPmk}^{Rqrd}\middle|\dot{W}_{Tak}^{Rqrd}\right\}}^{t^*\left\{\dot{W}_{CmPmk}^{Met}\middle|\dot{W}_{Tak}^{Met}\right\}} \left(\dot{W}_{Mtcek}^{AssIn} - \dot{W}_{Mtcek}^{AssSink}\right) dt \qquad (3.170)$$

$$\dot{W}_{Mtcek}^{AssIn} = \begin{cases} \dot{W}_{Mtcek}^{ActIn} & \left\{W_{Mtcek}^{ActIn} \leq W_{Mtcek}^{Av}\right\} \\ W_{Mtcek}^{Av} {t_{pw}^*}^{-1} & \{Otherwise\} \end{cases} \qquad (3.171)$$

$$\dot{W}_{Mtcek}^{AssSink} = W_{Mtcek}^{Ass} {t_{pw}^*}^{-1} \qquad \left\{W_{Mtcek}^{Ass} \geq W_{Mtcek}^{Rqst}\right\} \qquad (3.172)$$

$$W_{Mtcek}^{Av} = \int_{t=t^*\left\{\dot{W}_{CmPmk}^{Rqrd}\middle|\dot{W}_{Tak}^{Rqrd}\right\}}^{t^*\left\{\dot{W}_{CmPmk}^{Met}\middle|\dot{W}_{Tak}^{Met}\right\}} \left(\dot{W}_{Mtcek}^{AvIn} - \dot{W}_{Mtcek}^{AssIn} - \dot{W}_{Mtcek}^{CaRqrd}\right) dt \qquad (3.173)$$

$$\dot{W}_{Mtcek}^{AvIn} = W_{Mtcek}^{Rqst} {t_{pw}^*}^{-1} \qquad \left\{0 < E_{Modek}^{WRqst} \leq 3\right\} \qquad (3.174)$$

$$\dot{W}_{Mtcek}^{CaRqrd} = W_{Mtcek}^{Av} {t_{pw}^*}^{-1} \qquad \left\{\dot{W}_{Mtcek}^{AvIn} \neq 0\right\} \qquad (3.175)$$

(3) Active Maintenance workers

The active maintenance workers (W_{Mtcek}^{Act}) is a state quantity that accounts for the number of operators that are carrying out maintenance action on E_k at any particular time during the plant operation period. It was formulated in the study as the integral of the difference between the number of workers that start action $\left(\dot{W}_{Mtcek}^{ActIn}\right)$ and those that end action $\left(\dot{W}_{Mtcek}^{ActOut}\right)$ on the equipment within any interval during plant operation period (Equation 3.176). $\dot{W}_{Mtcek}^{ActIn}$ taken as the exact value of the number of requested maintenance workers allocated to E_k after a delay period ($t_{MAss}^{Strt} = t_{MAss}^{Strt*}$) provided that the following conditions hold at the time of the allocation,

i. The number of maintenance workers undertaking action on the equipment at the time of request are less the total sum of workers requested.

ii. There is no maintenance worker recruitment in process at the time of workers allocation.

iii. The number of maintenance personnel in the system who are currently inactive (have not been assigned maintenance duties) [W_{mtce}^{Inact}] must be equal or exceed the total number of personnel requested for $\left(W_{MtceS}^{Rqstd}\right)$ to carry out maintenance tasks on all the equipment that require maintenance

These conditions are quantitatively described in equations 177 and 178. Thus for any maintenance task, if W_{Mtcek}^{Act} has a value that lies between zero and $W_{Mtcek}^{Rqst} - 1$, then by implication no maintenance action can be undertaken on E_k since the number of active workers are inadequate to complete the maintenance task.

$$\int_{W_{Mtcek}^{Act}\{t=t^*\}}^{W_{Mtcek}^{Act}\{t=T^*\}} dW_{Mtcek}^{Act} = \int_{W_{Mtcek}^{Act}\{t=t^*\}}^{W_{Mtcek}^{Act}\{t=T^*\}} \left(\dot{W}_{Mtcek}^{ActIn} - \dot{W}_{Mtcek}^{ActOut}\right)dt \qquad (3.176)$$

$$\dot{W}_{Mtcek}^{ActIn} = W_{Mtcek}^{Rqst} \qquad \{A\} \qquad (3.177)$$

$$W_{MtceS}^{Rqstd} = \sum_{k=1}^{K} W_{Mtcek}^{Rqst} \qquad (3.178)$$

$$A: W_{Mtcek}^{Act} < W_{Mtcek}^{Rqst}; W_{Proc}^{Rcrit} = 0; W_{mtce}^{Inact} \geq W_{MtceS}^{Rqstd}; t_{MAss}^{Strt} = t_{MAss}^{Strt*}$$

The $\dot{W}_{Mtcek}^{ActOut}$ on the other hand occurs when maintenance action has been completed and the equipment is restarted for production operation ($\dot{E}_k^{Mtce} = 0; \dot{E}_k^{Rsrt} > 0|$). This scenario can also take place when allocated maintenance workforce is cancelled $\left(\dot{E}_k^{Rsrt} = 0; \dot{W}_{Mtcek}^{AvIn} > 0\right)$. $\dot{W}_{Mtcek}^{ActOut}$ is also affected by the a delay factor $(t_{MAss}^{Done} = t_{MAss}^{Done*})$. t_{MAss}^{Done*} describes the time it may take as a result of inspection, rework, administrative bottlenecks etc. to terminate assigned maintenance responsibilities [Equation 3.160].

$$\dot{W}_{Mtcek}^{ActOut} = W_{Mtcek}^{Act} \qquad \{B\} \tag{3.179}$$

$$B: \dot{E}_k^{Mtce} = 0; \dot{E}_k^{Rsrt} > 0 \Big| \left(\dot{E}_k^{Rsrt} = 0; \dot{W}_{Mtcek}^{AvIn} > 0\right); t_{MAss}^{Done} = t_{MAss}^{Done*}$$

(4) Inactive Maintenance workers

This state quantity (W_{mtce}^{Inact}) reflects the number of maintenance workers that are existent in the in the system but not yet assigned for maintenance actions. A change in this quantity at any time was determined as the totality of the active maintenance workers that start and complete maintenance activities for all equipment $(\forall E_k)$ in the system together with the rate at which maintenance personnel enter or leave the system as a result of recruitment and retrenchment situations (Equation 3.180).

$$\frac{dW_{mtce}^{Inact}}{dt} = \left(\sum_{k=1}^{K} \dot{W}_{Mtcek}^{ActIn} + \dot{W}_S^{Hire}\right) - \left(\sum_{k=1}^{K} \dot{W}_{Mtcek}^{ActOut} + \dot{W}_S^{Fire}\right) \tag{3.180}$$

The $\dot{W}_S^{Hire}$ is the rate at which fresh maintenance personnel are introduced into the system. The number of personnel hired was formulated to be dependent on the total number of maintenance personnel in service, the maximum maintenance personnel threshold desired by the organisation and the number of personnel available to the organisation for recruitment (Equation 3.181). Also, $\dot{W}_S^{Hire}$ was modelled to occur after a period of delay $\left(t_{mtce}^{DRcrit} = t_{mtce}^{DRcrit*}\right)$. This delay may occur due to issues related to recruitment and training processes and activities. It could also include desired skill availability and other organisational influence bottlenecks

$$\dot{W}_S^{Hire} = \begin{cases} W_{MtceS}^{Max} - W_{MSrv}^{Tot} & \left\{A; \left(W_S^{Rcrit} + W_{MSrv}^{Tot}\right) > W_{MtceS}^{Max}\right\} \\ W_S^{Rcrit} & \left\{A; \left(W_S^{Rcrit} + W_{MSrv}^{Tot}\right) \le W_{MtceS}^{Max}\right\} \end{cases} \tag{3.181}$$

$$\text{A}: t_{mtce}^{DRcrit} = t_{mtce}^{DRcrit*}; W_{MSrv}^{Tot} < W_{MtceS}^{Max}$$

The $\dot{W}_S^{Fire}$ on the other hand is the rate of maintenance personnel outflow and describes the rate at which the system loses part of its maintenance workforce. Two major situations were considered in the release of maintenance personnel from the system. These considerations focused on

i. The ability of the maintenance operation fund to cater for the incentives of all the maintenance personnel currently in the system. Thus, at any time when the maintenance fund capability $\left(W_{MFund}^{Cap}\right)$ was lower than the total maintenance personnel in service (W_{MSrv}^{Tot}), then $W_{MSrv}^{Tot} - W_{MFund}^{Cap}$ maintenance workers are fired.
ii. The need to optimise workforce cost such that the total workforce personnel for maintenance (W_{MSrv}^{Tot}) was limited to or as close as possible to a minimum threshold $\left(W_{MtceS}^{Min}\right)$ (as determined by the organisation) particularly in situations when regular (corrective and preventive) maintenance was being undertaken. Thus in periods when there is no need for the assignment of maintenance personnel to tasks ($S_{mtce}^{WAss} = 0$), if $W_{MSrv}^{Tot} > W_{MtceS}^{Min}$, then $W_{MSrv}^{Tot} - W_{MtceS}^{Min}$ number of maintenance personnel are fired.

The mathematical formulation of these scenarios is described in Equations 182 - 184.

$$\dot{W}_S^{Fire} \begin{cases} W_{MSrv}^{Tot} - W_{MFund}^{Cap} & \{D\} \\ W_{MSrv}^{Tot} - W_{MtceS}^{Min} & \{E\} \\ W_{mtce}^{Inact} & \{F|G\} \end{cases} \tag{3.182}$$

$$W_{MSrv}^{Tot} = W_{Mtce}^{Inact} + W_{mtce}^{Act} \tag{3.183}$$

$$W_{MFund}^{Cap} = \frac{B_{MP}}{C_{mtce}^{WWage}} \tag{3.184}$$

$$D: W_{MFund}^{Cap} < W_{MSrv}^{Tot}; W_{mtce}^{Inact} \geq \left(W_{MSrv}^{Tot} - W_{MFund}^{Cap}\right)$$
$$E: S_{mtce}^{WAss} = 0; W_{MSrv}^{Tot} > W_{MtceS}^{Min}; W_{mtce}^{Act} < W_{MtceS}^{Min}$$
$$F: W_{MFund}^{Cap} < W_{MSrv}^{Tot}; W_{mtce}^{Inact} < \left(W_{MSrv}^{Tot} - W_{MFund}^{Cap}\right)$$
$$G: S_{mtce}^{WAss} = 0; W_{MSrv}^{Tot} > W_{MtceS}^{Min}; W_{mtce}^{Act} \geq W_{MtceS}^{Min}$$

(5) Maintenance workforce Recruitment

The maintenance workforce recruitment state quantity $\left(W_S^{Rcrit}\right)$ was formulated to account for hiring activities that take place when new or extra maintenance personnel are needed in the liquefaction plant. This need may stem from a drop in expected regular maintenance productivity or to outsource maintenance functions. A change in this state at any time within the production window is caused by the difference between the $(\dot{W}_S^{Rcrit})$ and $\dot{W}_S^{Hire}$ (Equation 3.185).

$$W_S^{Rcrit} = \dot{W}_S^{Rcrit} - \dot{W}_S^{Hire} \tag{3.185}$$

$\dot{W}_S^{Rcrit}$ captures the periodic inflow of maintenance workers for recruitment purposes and is a product of the maintenance constrained maintenance (W_{mtce}^{Cgap}) personnel gap and the maintenance resource availability factor (f_{mtce}^{ReAv}) (Equation 3.186). f_{mtce}^{ReAv} was modelled as a quantity with value between 0 and 1 where the former reflects the absolute scarcity while the latter represents absolute availability respectively of the type(s) of personnel desired for recruitment.

$$\dot{W}_S^{Rcrit} = W_{mtce}^{Cgap} f_{mtce}^{ReAv} \qquad \{t_{mtce}^{DRcrit} = 0\} \tag{3.186}$$

W_{mtce}^{Cgap} on the other hand, is a quantity that identifies the realistic number of workforce personnel that the system can afford to cater for. The quantity's outcome is determined by comparing between the number of personnel that the system desires for maintenance work execution (W_{mtce}^{Dgap}) with the maintenance workers currently in service (W_{MSrv}^{Tot}) and the resource funding capability of the system (W_{MFund}^{Cap}) [Equation 3.187]

$$\begin{cases} W_{mtce}^{Dgap} & \{(W_{mtce}^{Dgap} + W_{MSrv}^{Tot}) \le W_{MFund}^{Cap}\} \\ W_{MFund}^{Cap} - W_{MSrv}^{Tot} & \{(W_{mtce}^{Dgap} + W_{MSrv}^{Tot}) > W_{MFund}^{Cap}; W_{MSrv}^{Tot} < W_{MFund}^{Cap}\} \\ 0 & \{Otherwise\} \end{cases} \tag{3.187}$$

W_{mtce}^{Dgap} reflects the totality of regular (W_{MReg}^{gap}) and non-regular (W_{MNReg}^{gap}) maintenance personnel gaps identified in the system (Equations 188-190)

$$W_{mtce}^{Dgap} = W_{MReg}^{gap} + W_{MNReg}^{gap} \tag{3.188}$$

$$W_{MReg}^{gap} = \begin{cases} W_{mtce}^{gap} & \{(W_{mtce}^{gap} + W_{MSrv}^{Tot}) \le W_{MtceS}^{Min}\} \\ W_{MtceS}^{Min} - W_{MSrv}^{Tot} & \{(W_{mtce}^{gap} + W_{MSrv}^{Tot}) > W_{MtceS}^{Min}; W_{MSrv}^{Tot} < W_{MtceS}^{Min}\} \\ 0 & \{Otherwise\} \end{cases} \tag{3.189}$$

$$W_{MNReg}^{gap} = \begin{cases} W_{mtce}^{gap} & \{W_{MtceS}^{Min} < (W_{mtce}^{gap} + W_{MSrv}^{Tot}) \le W_{MtceS}^{Max}\} \\ W_{mtce}^{gap} + W_{MSrv}^{Tot} - W_{MtceS}^{Max} & \{(W_{mtce}^{gap} + W_{MSrv}^{Tot}) > W_{MtceS}^{Min}, W_{MtceS}^{Max}\} \\ W_{MtceS}^{Min} - W_{MSrv}^{Tot} & \{(W_{mtce}^{gap} + W_{MSrv}^{Tot}) < W_{MtceS}^{Min}\} \end{cases} \tag{3.190}$$

(6) The maintenance personnel gap

The maintenance personnel gap $\left(W_{mtce}^{gap}\right)$, although not a state quantity, plays an important significant role in the maintenance human resources sub sector. W_{mtce}^{gap} provides information on the maintenance personnel requirement $\left(W_{Mtce}^{Rqrd}\right)$ desired for executing maintenance functions at any period in the system. W_{Mtce}^{Rqrd} was formulated as the totality of the workforce needed arising from corrective $\left(W_{Cm}^{Rqrd}\right)$, preventive $\left(W_{Pm}^{Rqrd}\right)$ and turnaround $\left(W_{TaM}^{Rqrd}\right)$ maintenance policy related equipment issues arising in that period (Equation 3.191).

$$W_{mtce}^{gap} = W_{Mtce}^{Rqrd} = \sum_{i=1}^{3} W_i^{Rqrd} \tag{3.191}$$

$$i(1 = TA;\ 2 = PM;\ 3 = CM)$$

W_i^{Rqrd} was determined as the outcome of the maintenance workforce pressure (W_i^{Press}) that arise with respect to the maintenance policy i (f_{Reci}^{Dec}) adopted by the organisation and will hold for any i only if such policy has been adopted (Equations 192 - 194). It can be observed from Equation 3.192 that the maintenance priority was given to the corrective maintenance policy such that when W_{Cm}^{Rqrd} is desired, the human resource acquisition is prioritised over the other policies so as to get the plant running again. This prioritisation distils over to affect situations of turn around maintenance (Equation 3.194) where a situation may arise such that the plant becomes unavailable as a result of an unplanned failure. However, if it is observed that the repair time of the equipment will take longer than the start time of the scheduled turnaround maintenance action ($t_S^I \geq t_k^{ToTa}$), then the turnaround action is rescheduled to align with the repair start time of the failed equipment.

$$W_{Cm}^{Rqrd} = W_{Cm}^{Press} \quad \{f_{RecCm}^{Dec} = 1\} \tag{3.192}$$

$$W_{Pm}^{Rqrd} = W_{Pm}^{Press} \quad \{f_{RecPm}^{Dec} = 1; t_{PmCdn}^{WRec} = 1\} \tag{3.193}$$

$$W_{Pm}^{Rqrd} = W_{Pm}^{Press} \quad \left\{f_{RecTa}^{Dec} = 1; t_{PmCdn}^{WRec} = 0 \middle| t_{PmCdn}^{WRec} > 0; t_S^I \geq t_k^{ToTa}\right\} \tag{3.194}$$

Where $t_{PmCdn}^{WRec}$and t_{TaCdn}^{WRec} (Equations 3.195 - 3.196) are the preventive and turnaround maintenance countdown. These represent intervals that are usually deployed by organisations for planning towards the recruitment and assignment of workforce towards planned maintenance activities.

$$t_{PmCdn}^{WRec} = min(t_{PmCdnk}^{WRec}) \tag{3.195}$$

$$t_{qCdnk}^{WRec} = t_k^{ToPm} - t_{mtce}^{DRcrit} \qquad \{\forall q(q: PM; TA); \forall k\} \tag{3.196}$$

W_i^{Press} (Equations 3.197- 3.200) are workforce personnel that are desired when equipment fails (in the case of unplanned failures) or workforce requirements for planned current or backlogged maintenance workload anticipated during the preventive or turnaround maintenance countdown intervals. These were formulated by projecting into the future to estimate the number of maintenance personnel that will still be available $\left(W_{MPerc}^{Avail}\right)$ and those that will not be available $\left(W_{MPerc}^{Uvail}\right)$ in the at the time any of the type of maintenance action was due (Equations 201 – 203).

$$W_{Cm}^{Press} = \frac{W_{CmTot}^{Rqst}}{\sum_{i=2}^{3} W_{vTot}^{Rqst}} \left(\left[\sum_{v=2}^{3} W_{iTot}^{Rqst} \right] - W_{MPerc}^{Avail} \right) \quad \{G_3\} \tag{3.197}$$

$$W_{Pm}^{Press} = \frac{W_{PmTot}^{Rqst}}{\sum_{i=1}^{2} W_{vTot}^{Rqst}} \left(\left[\sum_{v=2}^{3} W_{iTot}^{Rqst} \right] - W_{MPerc}^{Avail} \right) \left\{ G_2; E_{Pm}^{WRqst} = 1; t_{PmCdn}^{WRec} \geq 1 \right\} \tag{3.198}$$

$$W_{Ta}^{Press} = W_{TaTot}^{Rqst} - W_{MPerc}^{Avail} \quad \left\{ G_1; E_{Ta}^{WRqst} = 1; t_{TaCdn}^{WRec} \geq 1 \right\} \tag{3.199}$$

$$G_i = W_{iTot}^{Rqst} > W_{MPerc}^{Avail} \quad \{(i: 1 = Ta; 2 = PM; 3 = CM)\} \tag{3.200}$$

$$W_{MPerc}^{Avail} = W_{MSrv}^{Tot} - W_{Perc}^{Uvail} \tag{3.201}$$

$$W_{Perc}^{Uvail} = \sum_{k=1}^{K} W_{Perck}^{Uvail} \tag{3.202}$$

$$W_{Perck}^{Uvail} = W_{Mtcek}^{Act} \quad \left\{ (t_k^{CmI} - E_{Prock}^{Mtce}) > t_{Mtce}^{DRcrit*} \right\} \tag{3.203}$$

3.8.6 Equipment spares and inventory management

This subsector of the maintenance sector is concerned with the analysis of the ordering, storing and utilisation of the liquefaction plant equipment spares for the purpose of ensuring optimal plant availability. The concern of this sector is to study the effect of the availability or non-availability of equipment spares and materials on equipment maintenance and availability. To this end consideration was not given to specific inventory types. Rather, all material and spares were described in terms of their monetary value.

3.8.7 Context of the equipment spares and inventory management subsector

In this study, the totality in time of carrying out maintenance action on any equipment was considered to be an intervention and was referred to as such. Thus, each periodic maintenance intervention on E_k was assumed to incur a periodic intervention cost which was either consumed through corrective/preventive maintenance $\left(\ddot{C}_{CPmk}^{IntCst}\right)$ or turnaround maintenance $\left(\ddot{C}_{Tak}^{IntCst}\right)$ and to these cost items corresponding expenses $\left(\ddot{C}_{CPmk}^{IntEx}\text{ and }\ddot{C}_{Tak}^{IntEx}\right)$ are made through the material usage rate $\left(\ddot{M}_{Matk}^{Usage}\right)$ as long as the value inventory at hand (M_{Hand}^{Inv}) is more than enough to support the requirement.

However, if M_{Hand}^{Inv} is depleted to or below the reorder point $\left(M_{Point}^{Rordr}\right)$ value, then inventory is ordered is made based on a lot size decision $\left(M_{Lot}^{Ordr}\right)$. The inventory is delivered after a delayed lead period and finally received and integrated with M_{Hand}^{Inv}. The causal quantities and their interactions are shown in Figure 3.14.

3.8.8 Stock and flow equation development for spares and inventory management

Based on the contextual problem and its subsequent causal analysis the inventory on hand (M_{Hand}^{Inv}) and delayed inventory (M_{Del}^{Inv}) were identified as the stock quantities (Figure 3.15). The stock and flow equation formulation regarding this subsector was done by describing the identified state quantities in terms of the interacting auxiliary and input quantities. In addition, the formulation of the equations of certain output quantities which bear some impact in other sectors and subsectors were also done. These output quantities are spare availability signals for corrective/preventive maintenance $\left(E_{CmPm}^{SpAv}\right)$ and turnaround maintenance $\left(E_{Ta}^{SpAv}\right)$ respectively.

(1) Inventory on hand

The inventory at hand describes the state of maintenance spares and materials available in the plant. The cause of a change in this state condition at any operation time was formulated to be due to the inventory utilisation rate $\left(\dot{M}_{Hand}^{InvOut}\right)$ and the inventory receiving rate $\left(\dot{M}_{Hand}^{InvIn}\right)$ [Equation 3.204].

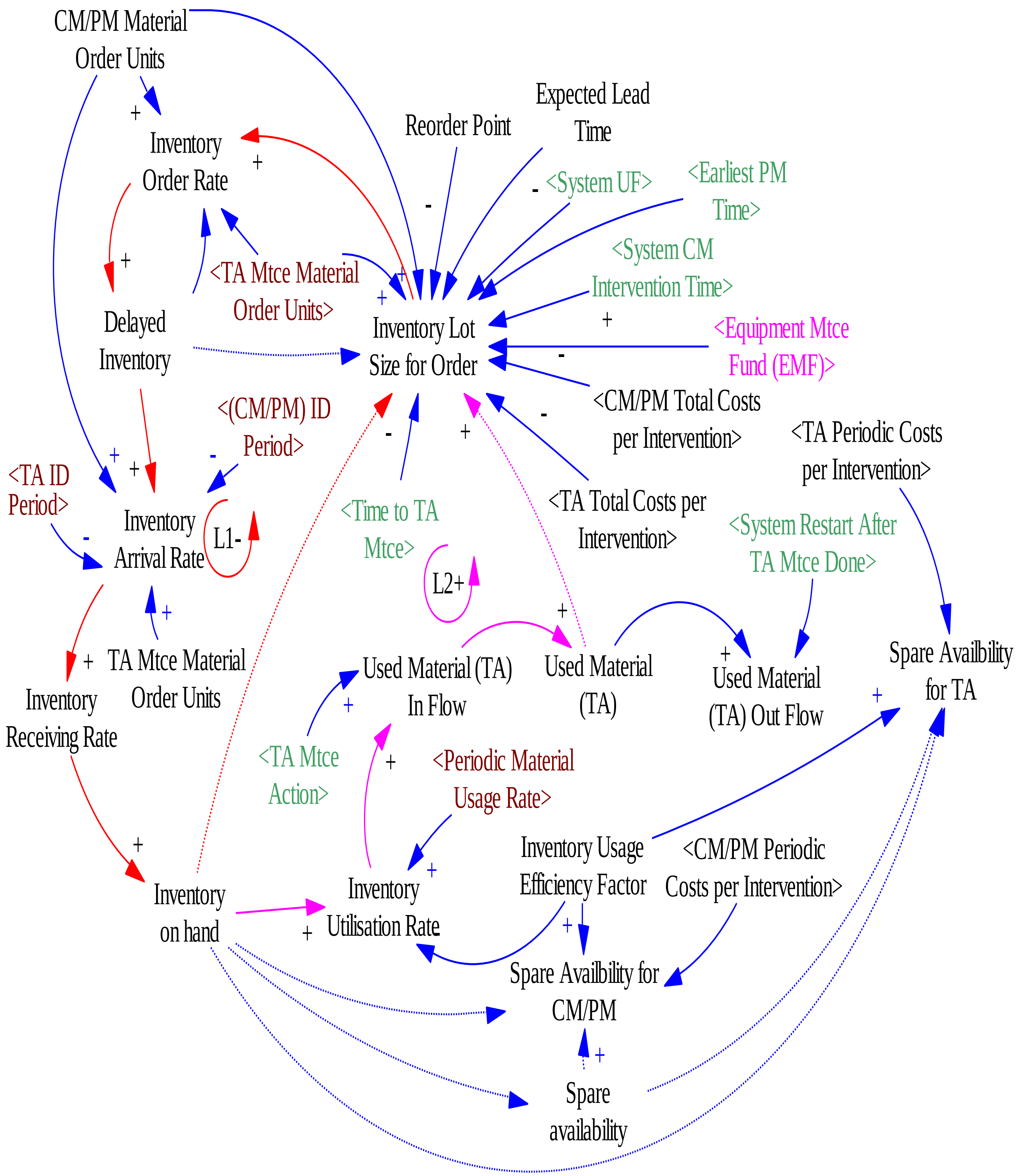

Figure 3.14: Causal diagram of the inventory management subsector

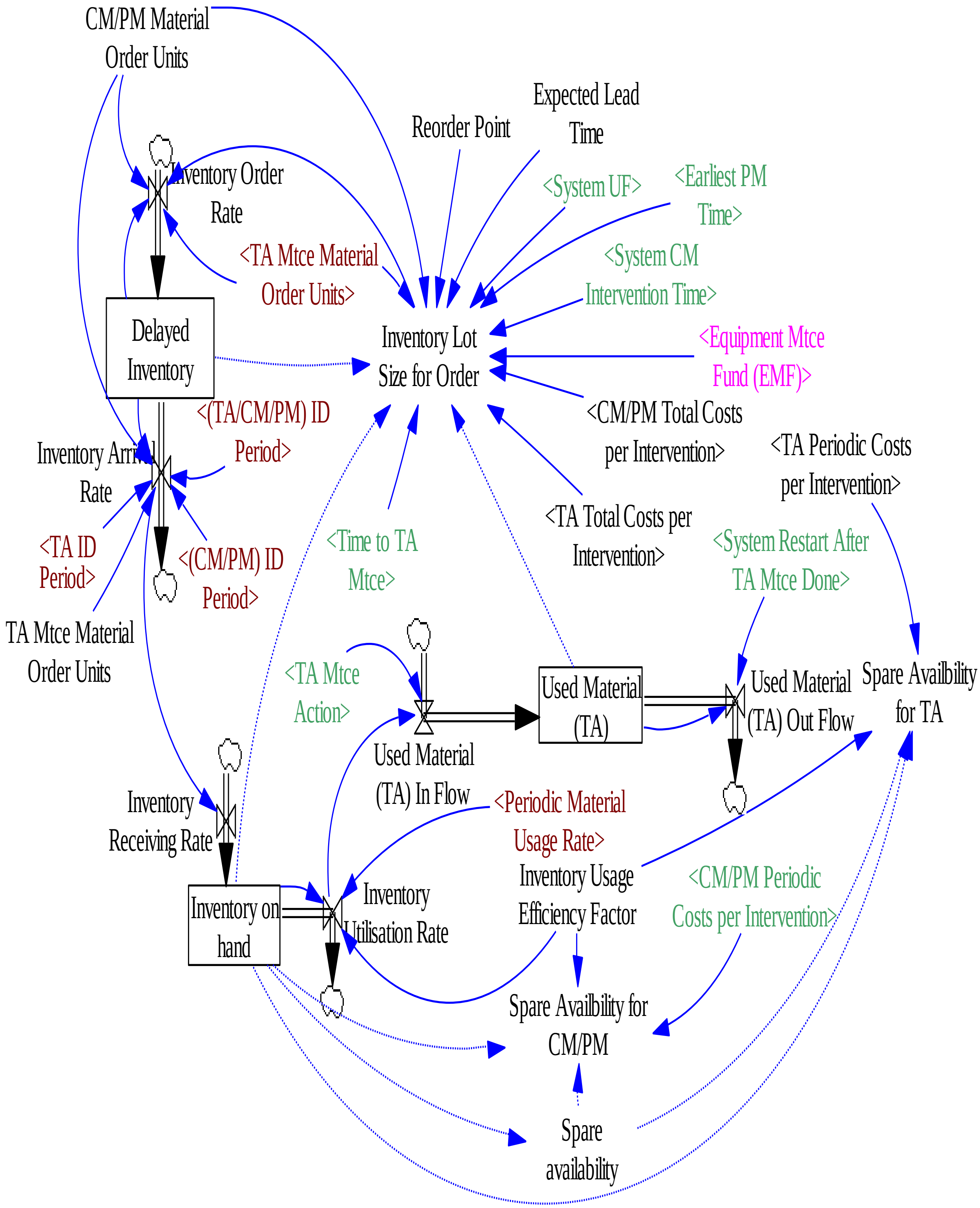

Figure 3.15: Stock and flow diagram of the inventory management sub-sector

$$\frac{dM_{Hand}^{Inv}}{dt} = \dot{M}_{Hand}^{InvIn} - \dot{M}_{Hand}^{InvOut} \tag{3.204}$$

$\dot{M}_{Hand}^{InvIn}$ describes the rate of materials receipt after they may have been ordered and is a direct function of the inventory arrival rate $\left(\dot{M}_{Hand}^{InvIn} = \dot{M}_{Ordr}^{Out}\right)$.

The inventory utilisation rate on the other hand, was seen to be affected by the product periodic material usage rate $\left(\ddot{M}_{Mat}^{Usage}\right)$ and the inverse degree of efficiency of usage of received materials $\left(f_{Usage}^{InvEff}\right)$ [Equation 3.205]. The implication of Equation 3.205 is that the rate of material utilisation increases as the usage efficiency decreases and *vice-versa*. where $\ddot{M}_{Mat}^{Usage}$ encompassed the total amount of materials used by E_k $\{\forall k\}$ within a particular period.

$$\dot{M}_{Hand}^{InvOut} = \ddot{M}_{Mat}^{Usage} f_{Usage}^{InvEff^{-1}} \tag{3.205}$$

(2) Delayed Inventory

The state of delayed inventory captures the scenario where inventory that has already been ordered is not delivered on order as a result of factors such as supplier proximity, product availability and logistics-related issues. Thus, this quantity was formulated such that once the materials have been ordered, then the ordered materials are immediately placed in a delay phase. The change in the quantity of material delayed M_{Del}^{Inv}, was determined as the difference between the rate of inventory order $\left(\dot{M}_{Ordr}^{In}\right)$ and inventory receipt $\left(\dot{M}_{Ordr}^{Out}\right)$ [Equation 3.206]

$$M_{Del}^{Inv} = \dot{M}_{Ordr}^{In} - \dot{M}_{Ordr}^{Out} \tag{3.206}$$

$\dot{M}_{Ordr}^{In}$ was determined to be affected by the amount of material required for corrective/preventive maintenance $\left(M_{MCPm}^{Ordr}\right)$, turnaround maintenance $\left(M_{MTa}^{Ordr}\right)$, the inventory lot size to be ordered $\left(M_{Lot}^{Ordr}\right)$ as may be decided upon by the organisation and the current size of M_{Del}^{Inv}. However, the quantity to be ordered was based on some conditions outlined as follows.

i. A complete lot size decided on can be ordered if an already delayed order is inexistent $(M_{Del}^{Inv} \leq 0)$. However,

ii. If a delayed order already exists ($M_{Del}^{Inv} > 0$), and the delayed inventory occurred from an order for corrective/preventive maintenance, then if M_{Lot}^{Ordr} is for turnaround maintenance, the ordered lot is added as delayed inventory.

iii. If a delayed order already exists ($M_{Del}^{Inv} > 0$), and the delayed inventory occurred from an order for turnaround maintenance, if M_{Lot}^{Ordr} is for corrective/preventive maintenance, then the ordered lot is added as delayed inventory.

iv. No material lot size can be ordered for corrective/preventive maintenance ($\dot{M}_{Ordr}^{In} = 0$) if a delayed order of M_{MCPm}^{Ordr} magnitude already exists $\left(M_{Del}^{Inv} = M_{MCPm}^{Ordr}\right)$. This condition also applies in the case where $\dot{M}_{Ordr}^{In} = 0$, given that $M_{Del}^{Inv} = M_{MTa}^{Ordr}$

These conditions are mathematically described in Equation 3.207.

$$\dot{M}_{Ordr}^{In} = \begin{cases} M_{Lot}^{Ordr} & \left\{M_{Lot}^{Ordr} \leq 0 \middle| M_{Lot}^{Ordr} > 0; M_{Del}^{Inv} \neq M_{Lot}^{Ordr}\right\} \\ 0 & \{Otherwise\} \end{cases} \quad (3.207)$$

Furthermore, $\dot{M}_{Ordr}^{Out}$ was formulated as also being dependent on $M_{Del}^{Inv}, M_{MCPm}^{Ordr}$ and M_{MTa}^{Ordr} as well as on the periods of delay of the order types $\left(t_{CPm}^{InvDel}\right.$ and $\left.t_{Ta}^{InvDel}\right)$. The delayed inventory was formulated to arrive at the expiration of any of the delay periods (Equation 3.208).

$$\dot{M}_{Ordr}^{Out} = \begin{cases} M_{MCPm}^{Ordr} & \left\{t_{CPm}^{InvDel} = 1; t_{Ta}^{InvDel} = 0; M_{Del}^{Inv} = M_{Lot}^{Ordr} + M_{Del}^{Inv}\right\} \\ M_{MCPm}^{Ordr} & \left\{t_{CPm}^{InvDel} = 0; t_{Ta}^{InvDel} = 1; M_{Del}^{Inv} = M_{Lot}^{Ordr} + M_{Del}^{Inv}\right\} \\ M_{Del}^{Inv} & \left\{t_{CPm}^{InvDel} = 1; t_{Ta}^{InvDel} = 1; M_{Del}^{Inv} = M_{Lot}^{Ordr} + M_{Del}^{Inv}\right\} \end{cases} \quad (3.208)$$

(3) Material lot size for order estimation

The material lot size for order $\left(M_{Lot}^{Ordr}\right)$ is the quantity of material that is usually decided on for order by management. A decision on this quantity could arise from several factors that relate to the previous, current and anticipated future maintenance dynamics in the system. It was considered an important factor as its value has the potential to impact the overall performance of the plant.

Based on the observations and interviews made in the studied LNG firm together with literature investigations, the M_{Lot}^{Ordr} was formulated based on fourteen interacting factors namely, the order quantities for preventive/corrective maintenance respectively and their corresponding costs per intervention (C_{CPm}^{PerInt} and C_{Ta}^{PerInt}), the inventory at hand, the delayed inventory, the reorder point $\left(M_{Point}^{Rordr}\right)$, unplanned failure events in the system $\left(E_S^{Uf}\right)$ and corresponding intervention time (t_S^I). The other factors are the earliest preventive maintenance time $\left(t_{Pm}^{Earlst}\right)$, the time to turnaround maintenance (t_S^{ToTa}), the amount of inventory utilise for turnaround maintenance in real-time (M_{MatTa}^{Use}) and the funds available for equipment maintenance activities (F_{Mtce}).

Based on the uncertain nature of the conditions that affect the lot order decision process, twenty sets of rules that take into consideration the potential occurrence of thirteen potential conditions were deployed to formulate M_{Lot}^{Ordr} decisions. The set of rules and conditions are shown in Table 3.2 and holds that an inventory lot size for an order for a rule type is decided upon if all the conditions that relate to that rule simultaneously occur at the time of the decision-making process.

3.9 Liquefaction plant life cycle estimation

To be able to facilitate strategy evaluations and decision-making on how best to change, enhance and improve the LNG system for sustained performance *vis-a-vis* the dynamic behaviour of interacting quantities of the identified LNG production sector, there was the need to estimate the life cycle cost (LCC) of the liquefaction plant. This was achieved in two phases. The first was concerned with the identification of the cost driver quantities of the system and the second was the formulation of the plant's LCC based on the identified cost drivers.

3.9.1 Identification of the SD-LNG-LCC cost driver quantities

Typically, the approach to identifying the LCC cost driver quantities was based on literature survey and responses from management personnel in the studied LNG firm. The plant life cycle costing is an activity in the financial sector of the model, however, the cost driver quantities occurred from all the sectors considered in the study.

Table 3.2: Inventory lot size for order decision based on potential conditional occurrences

M_{Lot}^{Ordr} Rule	Conditions for M_{Lot}^{Ordr} decision													M_{Lot}^{Ordr} Decision
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	
	$A < B$	$(A - B) < C$	$D \leq 0$	$D = \omega$	$D = \varphi$	$E = 1$	$F < G$	$(A + H) < I$	$G \leq J$	$K > \varphi$	$K > \omega$	$K > (\varphi + \omega)$	$L \leq J$	
1	∼	∼	∼	--	--	∼	∼	∼	∽	∼	--	--	--	φ
2	∼	∼	∼	--	--	∼	∼	∽	--	--	--	--	--	
3	∼	∼	∼	--	--	∽	--	∼	∽	∼	--	--	--	
4	∼	∼	∼	--	--	∽	--	∽	--	--	--	--	--	
5	∼	∼	∽	∼	--	∼	∼	--	--	∽	--	--	--	
6	∼	∼	∽	∼	--	∽	--	--	--	∽	--	--	--	
7	∽	--	∼	--	--	--	--	∼	∼	--	∼	--	∽	ω
8	∽	--	∽	--	∼	--	--	∼	∼	--	∽	--	--	
9	∼	∼	∼	--	--	∼	∼	∼	∼	--	--	∼	--	$\varphi + \omega$
10	∼	∼	∼	--	--	∽	--	∼	∼	--	--	∼	--	

Table 3.2 (continued): Inventory lot size for order decision based on potential conditional occurrences

M_{Lot}^{Ordr} Rule	Conditions for M_{Lot}^{Ordr} decision													M_{Lot}^{Ordr} Decision
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	
	$A < B$	$(A - B) < C$	$D \leq 0$	$D = \omega$	$D = \varphi$	$E = 1$	$F < G$	$(A + H) < I$	$G \leq J$	$K > \varphi$	$K > \omega$	$K > (\varphi + \omega)$	$L \leq J$	
11	∽	--	~	--	--	--	--	~	~	--	--	~	~	
12	~	~	~	--	--	~	~	~	~	--	--	∽	--	
13	~	~	~	--	--	~	~	~	∽	∽	--	--	--	
14	~	~	~	--	--	∽	--	~	~	--	--	∽	--	
15	~	~	~	--	--	∽	--	~	∽	∽	--	--	--	
16	~	~	∽	~	--	~	~	--	--	~	--	--	--	K
18	~	~	∽	~	--	∽	--	--	--	~	--	--	--	
19	∽	--	~	--	--	--	--	~	~	--	∽	--	∽	
20	∽	--	∽	--	~	--	--	~	~	--	~	--	--	

A: M_{Hand}^{Inv}; **B:** M_{Point}^{Rordr}; **C:** C_{CPm}^{TotInt}; **D:** M_{Del}^{Inv}; **E:** E_S^{Uf}; **F:** t_S^I; **G:** t_S^{ToTa}; **H:** M_{MatTa}^{Use}; **I:** C_{Ta}^{TotInt}; **J:** t_{lead}^{Avg}; **K:** F_{Mtce};**L:** t_{Pm}^{Earlst}; ω: M_{MTa}^{Ordr} ; φ: M_{MCPm}^{Ordr}

As such, they were tied to the periodic inflow of expenses incurred for liquefaction material usage, maintenance material management, labour, depreciation, overhead, shipping and interest paid on capital at the various subsectors' cost centres and corresponding value chain sectors. The LCC cost driver quantities and related items were then identified in terms of the cost centres from which they occurred and grouped under the sectors (Table 3.3). Figure 3.16 describes the time-influenced flow of the cost-driving quantities and related elements that influence the LCC accumulation.

3.9.2 Total life cycle equation Formulation

Deploying Figure 3.16, the total LCC of the LNG liquefaction operation (C_{LCC}^{Tot}) was formulated as the integral of the total cost accumulation within the system via the total LCC rate $\left(\dot{C}_{LCC}^{Tot}\right)$ (Equation 3.209). Where $\dot{C}_{LCC}^{Tot}$ sums up the cost driver quantities $\left(\dot{C}_{LCCj}^{Tot}[j = Liq, Lab, Mtce, DP, IC, OH, Trpn]\right)$ described in Table 3.3 (Equation 3.210).

$$\int_{C_{LCC}^{Tot}\{t=t^*\}}^{C_{LCC}^{Tot}\{T^*\}} C_{LCC}^{Tot} = \int_{t=t^*}^{T^*} \dot{C}_{LCC}^{Tot} dt \tag{3.209}$$

$$\dot{C}_{LCC}^{Tot} = \sum_{i=1}^{7} \dot{C}_{LCCj}^{Tot} \tag{3.210}$$

The general formulation for $\dot{C}_{LCCj}^{Tot}$ is shown in equation (3.211) and the formulation of each of the unique expense quantities in terms of their cost elements was carried out (Equations 3.211-3.234).

It is noteworthy here to point out that the depreciation cost relations (Equations 3.214, 3.219 and 3.233) were formulated to accommodate scenarios involving multiple brownfield expansions. Thus, equation 3.233 aggregates the depreciation costs arising from different brownfield capital projects that may occur at different periods of the plant's operating life. Equation 3.234 on the other hand, is an aspect of the TLCC that accounts for the costs incurred from conversion (liquefaction) operations only.

$$\dot{C}_{LCCLiq}^{Tot} = \dot{E}_{xFG} + \dot{E}_{xFuG} \tag{3.211}$$

$$\dot{C}_{LCCLab}^{Tot} = \dot{E}_{xLab} \tag{3.212}$$

Table 3.3: Various SD-LNG-LCC life cycle cost driver quantities, corresponding cost centres and cost driver elements

SN	Cost driver (Expense quantity)	Cost driver Quantity (Notation)	Subsector of cost centre (Activity Sector)	Cost driver element (Notation)
1	Liquefaction material usage costs (Feed Gas Expense Flow, Fuel Gas Expenditure Flow)	1. Periodic Feed Gas Usage Cost $\left(\ddot{C}_{FG}^{Usage}\right)$	Liquefaction Operation (Midstream Operation)	• LNG Stock Price (C_{LNG}^{Gas}) • Production Start Rate $\left(\dot{V}_{start}^{LNG}\right)$ • Site Complexity Factor $\left(f_{Site}^{Cmplx}\right)$ • Site Location Factor (f_{Site}^{Loc}) • Feed Gas FLF (K_{FG}^{FLF})
		2. Periodic Energy Cost $\left(\ddot{C}_{Energy}^{Usage}\right)$	Liquefaction Operation (Downstream Operation)	• System Availability Status (A_S^S) • Gas Volume Used as Fuel $\left(\dot{V}_{FuG}\right)$ • LNG Price (C^{LNG}) • Fuel Gas FLF (K_{FuG}^{FLF})
2	Maintenance material management costs (Equipment Maintenance Expenditure Flow)	Periodic Maintenance Cost $\left(\ddot{C}_{Mtce}\right)$	Maintenance operation (Downstream Operation)	• Inventory Ordering Costs $\left(\ddot{C}_{Ord}^{Inv}\right)$ • Inventory Holding Costs $\left(\ddot{C}_{Hold}^{Inv}\right)$ • Total Periodic Maintenance Cost $\left(\ddot{C}_{Mtce}^{Tot}\right)$ • Equipment Maintenance FLF (K_{FuG}^{FLF})
3	Labour Cost (Labour Expenditure Inflow	Production Labour Cost $\left(\ddot{C}_{Prod}^{Lab}\right)$	Production workforce management (Downstream Operation)	• Total Production Personnel (W_{Prod}^{Tot}) • Production Labour Wage Rate $\left(W_{Prod}^{Wage}\right)$
		Maintenance Labour Cost $\left(\ddot{C}_{Mtce}^{Lab}\right)$	Maintenance workforce management (Downstream Operation)	• Total Maintenance Personnel in Service (W_{MSrv}^{Tot}) • Maintenance Labour Wage Rate $\left(W_{Mtce}^{Wage}\right)$
				❖Labour FLF (K_{FuG}^{FLF}) ❖Inflation Factor (f^{Infl})

Table 3.3 (Continued): Various SD-LNG-LCC life cycle cost driver quantities, corresponding cost centres and cost driver elements

SN	Cost driver (Expense quantity)	Cost driver Quantity (Notation)	Subsector of cost centre	Cost driver element (Notation)
4	Depreciation costs (Depreciation Expenses Inflow)	Periodic Depreciation Expenses $\left(\ddot{E}_{xDP}\right)$	Budgeting (Downstream Operation)	• Total CAPEX Fund $\left(\hat{F}_{EX}^{TC}\right)$ • Plant Salvage value $\left(C_{slvg}\right)$ • Plant Useful Life (P_L) • Plant Operating Period (t^*)
5	Overhead costs (OH Expenditure Inflow)	Periodic OH Cost (C_{OH}^{O})	Budgeting (Downstream Operation)	• OPEX (Less OH, FG and DP Cost) Rate (E_{xFGDP}^{Less}) • OH Estimation Factor (f_{OH}^{Est}) • OH FLF (K_{FuG}^{FLF})
6	Shipping cost (Shipping Expenditure Inflow)	Periodic LNG Shipping Cost $\left(\ddot{C}_{Trpn}^{LNG}\right)$	Budgeting (Downstream Operation)	• LNG Cost per Shipping Trip $\left(C_{Trpn}^{ShipLNG}\right)$ • Shipping Rate (MMBTU) $\left[\dot{V}_{Order}^{shipBTU}\right]$
7	Interest paid on capital	Total Periodic Interest on capital $\left(\dot{C}_{LCCIC}^{Tot}\right)$	Budgeting (Downstream Operation)	• CAPEX Fund Inflow $\left(\dot{F}_{EX}^{C}\right)$ • Periodic Interest on Capital$\left(\dot{C}_{CF}^{Intrst}\right)$ • Discount Rate $\left(r^{Disc}\right)$ • Plant Operating Period (t^*) • Plant Useful Life (P_L) • Interest on Capital Policy (K_{CF}^{Intrst})

❖ **Affects all cost centres for specific cost driver quantity**

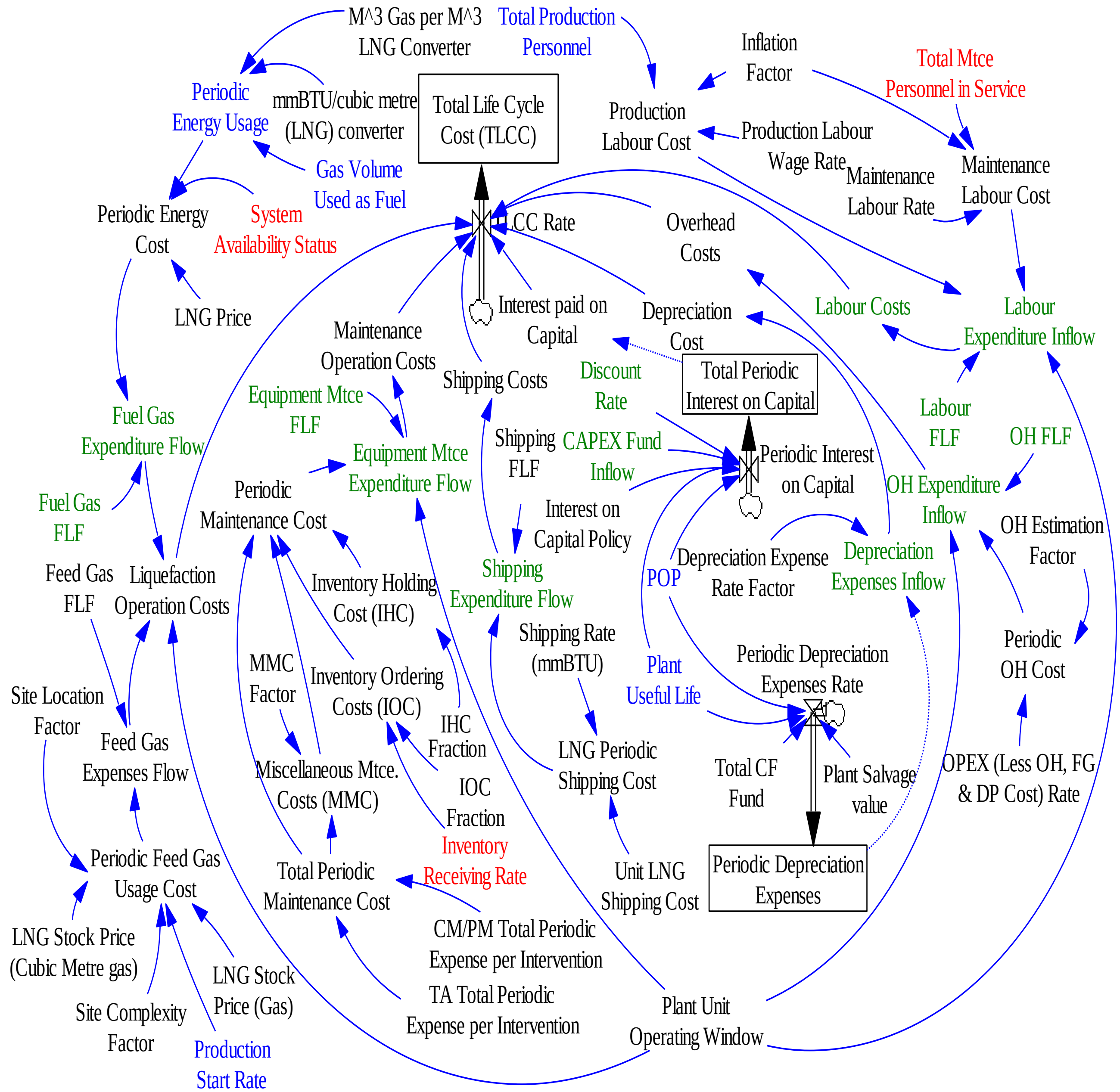

Figure 3.16: Stock and flow description of the SD-LNG-LCC cost driving quantities and elements

$$\dot{C}_{LCCLab}^{Tot} = \dot{E}_{xMtce} \tag{3.213}$$

$$\dot{C}_{LCCDP}^{Tot} = \dot{E}_{xDP} \tag{3.214}$$

$$\dot{C}_{LCCOH}^{Tot} = \dot{E}_{xOH} \tag{3.215}$$

$$\dot{C}_{LCCIC}^{Tot} = \hat{E}_{xCF}^{Intrst} \tag{3.216}$$

$$\dot{C}_{LCCTrpn}^{Tot} = \dot{E}_{xTrpn} \tag{3.217}$$

$$\dot{E}_{xFG} = \begin{cases} \ddot{C}_{FG}^{Usage}(1 + K_{FG}^{FLF}) & \left\{\dfrac{F_{FG}\Omega_{EX}^{O}}{t^*} \geq \ddot{C}_{FG}^{Usage}(1 + K_{FG}^{FLF})\right\} \\ \dfrac{F_{FG}\Omega_{EX}^{O}}{t^*} & \{Otherwise\} \end{cases} \tag{3.218}$$

$$\dot{E}_{xFuG} = \begin{cases} \ddot{C}_{Energy}^{Usage}(1 + K_{FuG}^{FLF}) & \left\{\dfrac{F_{FuG}\Omega_{EX}^{O}}{t^*} \geq \ddot{C}_{Energy}^{Usage}(1 + K_{FuG}^{FLF})\right\} \\ \dfrac{F_{FuG}\Omega_{EX}^{O}}{t^*} & \{Otherwise\} \end{cases} \tag{3.219}$$

$$\dot{E}_{xLab} = \begin{cases} \dfrac{\left[\ddot{C}_{Lab}(1 + K_{Lab}^{FLF})\right]}{f^{Infl}} & \left\{\dfrac{F_{Lab}\Omega_{EX}^{O}}{t^*} \geq \dfrac{\left[\ddot{C}_{Lab}(1 + K_{Lab}^{FLF})\right]}{f^{Infl}}\right\} \\ \dfrac{F_{Lab}\Omega_{EX}^{O}}{t^*} & \{Otherwise\} \end{cases} \tag{3.220}$$

$$\dot{E}_{xDP} = \frac{\ddot{E}_{xDP}}{f_{DP}^{Exp}} \tag{3.221}$$

$$\dot{E}_{xOH} = \begin{cases} \left[\ddot{C}_{OH}(1 + K_{OH}^{FLF})\right] & \left\{\dfrac{F_{Lab}\Omega_{EX}^{O}}{t^*} \geq \left[\ddot{C}_{OH}(1 + K_{OH}^{FLF})\right]\right\} \\ \dfrac{F_{F_{OH}}\Omega_{EX}^{O}}{t^*} & \{Otherwise\} \end{cases} \tag{3.222}$$

$$\hat{E}_{xCF}^{Intrst} = \left(\int_{t=t^*}^{t^*} \dot{C}_{CF}^{Intrst}(t)dt\right) - \hat{E}_{xCF}^{Intrst}\{t = t^*\} \qquad \{K_{CF}^{Intrst} = 1\} \tag{3.223}$$

$$\dot{E}_{xTrpn} = C_{Trpn}^{UnitLNG}\dot{V}_{Order}^{shipBTU} \tag{3.224}$$

$$\ddot{C}_{FG}^{Usage} = C_{LNG}^{Gas}\dot{V}_{start}^{LNG}f_{Site}^{Cmplx}f_{Site}^{Loc} \tag{3.225}$$

$$\ddot{C}_{Energy}^{Usage} = A_{S}^{S}\ddot{E}_{Energy}^{Usage}C^{LNG} \tag{3.226}$$

$$\ddot{C}_{Lab} = \ddot{C}_{Mtce}^{Lab} + \ddot{C}_{Prod}^{Lab} \tag{3.227}$$

$$\ddot{C}_{Mtce}^{Lab} = W_{MSrv}^{Tot} C_{mtce}^{Wage} \tag{3.228}$$

$$\ddot{C}_{Prod}^{Lab} = W_{Prod}^{Tot} C_{Prod}^{Wage} \tag{3.229}$$

$$\ddot{C}_{OH} = E_{xFGDP}^{Less} f_{OH}^{Est} \tag{3.230}$$

$$\dot{C}_{CF}^{Intrst} = 0.01 r^{Disc} P_L^{-1} \dot{F}_{EX}^{C} \tag{3.231}$$

$$\ddot{E}_{Energy}^{Usag\dot{e}} = V_{FuG} \left(\frac{f_{LNG}^{mmBTU}}{f_{LNG}^{Gas}} \right) \tag{3.232}$$

$$\ddot{E}_{xDP} = \int_{\ddot{E}_{xDP}\{t=t^*\}}^{\ddot{E}_{xDP}\{T^*\}} \ddot{E}_{xDP} = \int_{\ddot{E}_{xDP}\{t=t^*\}}^{\ddot{E}_{xDP}\{T^*\}} \left(\left[\hat{F}_{EX}^{TC} - C_{slvg} \right] \{t\} \right) dt \tag{3.233}$$

$$\dot{C}_{LCCPOps}^{Tot} = \dot{E}_{xFuG} + \dot{E}_{xLab} + \dot{E}_{xMtce} + \dot{E}_{xOH} \tag{3.234}$$

3.10 SD-LNG-LCC Models for Economic Analysis of Liquefaction Operations

The economic analysis sector of the SD-LNG LCC model is concerned with the provision of information regarding the economic viability of LNG projects. The sector was designed to track the cost of the LNG process and also undertake cash in-flow and out-flow valuations to determine the worth of the investment effort. The economic analysis sector was formulated to provide information on the life cycle status of the liquefaction process based on seven economic analysis models namely, unit production cost $\left(C_{Prod}^{UnitLNG}\right)$, total revenue (G_{Rev}^{Tot}), net present value (NPV) $[G_{LNG}^{NPV}]$, discounted total profit $\left(G_{LNG}^{Disc}\right)$, payback period $\left(t_{Back}^{Pay}\right)$, return on investment (P_{ROI}), the profitability index [PI] (P_{LNG}^{PI}), breakeven period $\left(t_{Even}^{Break}\right)$ and the breakeven quantity $\left(\mathrm{V}_{Even}^{Break}\right)$.

In addition, other measures that are commonly utilised in the assessment of LNG operations were also computed. They include different variants of the total and annual cost of OPEX and their related maintenance and production components. A system dynamics approach was also deployed in formulating these relations and the stock and flow model is shown in Figure 3.17. The compacted forms of the formulated equations are described in Equations 235 – 253 while the expanded versions are shown in Appendix C.

(1) Unit LNG Production Cost

From the formulations, the unit LNG production cost was obtained from the Total Life Cycle Cost divided by the heat equivalent $(in\, MMBTU)$ of the total volume of LNG produced $\left(V_{prod}^{TotLNG}\right)$ [Equation 3.235].

$$C_{Prod}^{UnitLNG} = \frac{C_{LCC}^{Tot}}{V_{prod}^{TotLNG} f_{LNG}^{mmBTU}} \qquad (3.235)$$

(2) Total Revenue

The total revenue (G_{Rev}^{Tot}) was gotten by integrating the revenue accrued from periodic LNG shipment/sales $\left(\ddot{G}_{Rev}\right)$. The $\dot{G}_{Rev}$ was obtained from the product of the unit cost of MMBTU of LNG and the heating equivalent of its periodic shipment (Equation 3.236).

$$G_{Rev}^{Tot} = \left(\int_{G_{Rev}^{Tot}\{t=t^*\}}^{G_{Rev}^{Tot}\{t=T^*\}} C^{LNG} \dot{V}_{LNG}^{shipped} f_{LNG}^{mmBTU} dt\right) + G_{Rev}^{Tot}\{t = t^*\} \qquad (3.236)$$

(3) Total Discounted Profit

Equation 3.237 shows that total profit from LNG shipment was determined as the integral of the difference between $\dot{G}_{Rev}^{Tot}$ and $\dot{C}_{LCC}^{Tot}$ discounted over the time under focus $(t^*,\, T^*)$ to account for the time value of money using the discount factor relationship (Equation 3.237) with discount rate value r^{Disc}.

$$G_{LNG}^{Disc} = \left(\int_{t=t^*}^{t=T^*} \frac{C^{LNG} \dot{V}_{LNG}^{shipped} f_{LNG}^{mmBTU} - \dot{C}_{LCC}^{Tot}}{\varpi} dt\right) + G_{LNG}^{Disc}\{t = t^*\} \qquad (3.237)$$

However, this formulation is valid only in situations where no other capacity expansions occur during the lifetime of the plant.

Regarding the latter scenario, G_{LNG}^{Disc} was determined as the sum of the discounted profits of all the base projects and their corresponding expansions $\left(G_{LNGq}^{Disc}\{q\colon 1,2,3,\ldots,Q\}\right)$ [Equation 3.238] with G_{LNGq}^{Disc} (Equation 3.239) formulated as the modified version of Equation 3.237. However, the boundary conditions and discounting periods for G_{LNGq}^{Disc} reflect the intervals within which the Greenfield or Brownfield projects existed

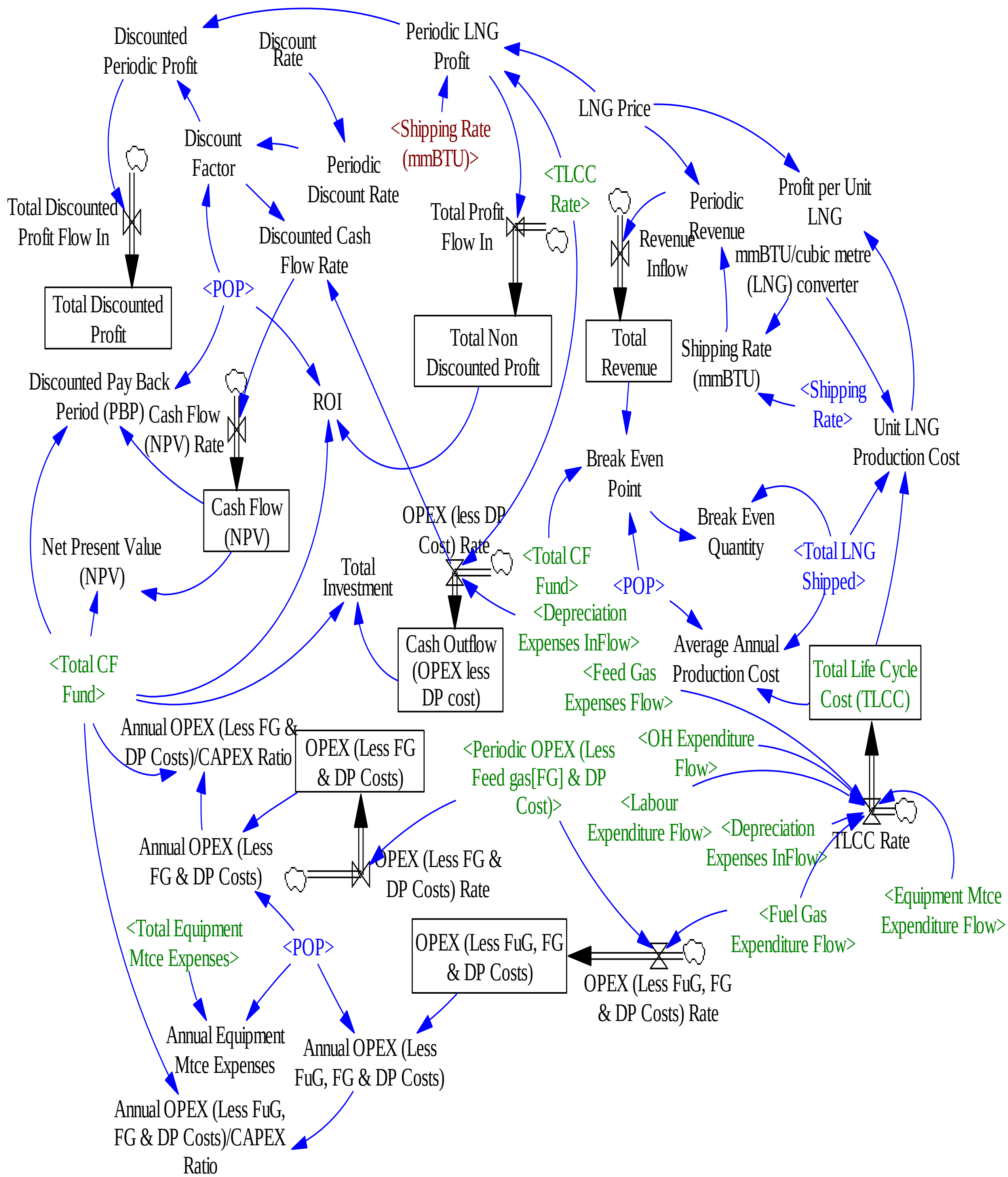

Figure 3.17: Stock and flow description of the economic analysis models formulated for LNG liquefaction plant analysis

$$G_{LNG}^{Disc} = \sum_{q=1}^{Q} G_{LNGq}^{Disc} \tag{3.238}$$

$$G_{LNGq}^{Disc} = \left(\int_{t_q^*=1}^{T_q^*} \frac{\left[\chi_q\left(C^{LNG}\dot{V}_{LNG}^{shipped} f_{LNG}^{mmBTU} - \dot{C}_{LCC}^{Tot}\right)\right]}{\varpi_q} dt \right) + G_{LNGq}^{Disc}\{t_q^*\} \quad \{\forall q\} \tag{3.239}$$

Where χ_q are the fraction of profits from LNG sales; t_q^* and T_q^* are the start and end times for base or expansion project q, while ϖ_q are the discount factors for the profits computed from t_q^* to T_q^*.

(4) Net Present Value and Profitability Index

The net present value of the operation (G_{LNG}^{NPV}) was determined as the difference between the total value of discounted total cash flows and the Total investment (C_{Inv}^{Tot}) within the time considered (Equation 3.240). The implication of the outcome of the analysis is such that if the value of G_{LNG}^{NPV} is positive, the project was considered as being profitable otherwise it was considered as being non-profitable.

$$G_{LNG}^{NPV} = G_{Cash}^{NPV} - C_{Inv}^{Tot} \tag{3.240}$$

Similar to how the discounted profits were formulated, the discounted total cash flows (G_{Cash}^{NPV}) was taken as the sum of the values of the periodic LNG profits and depreciation expenses $\left(\dot{E}_{xDP}\right)$ for Greenfield projects and corresponding Brownfield expansions (q) [Equations 3.241 -3.243].

$$G_{Cash}^{NPV} = \sum_{q=1}^{Q} G_{Cashq}^{NPV} \tag{3.241}$$

$$G_{Cashq}^{NPV} = \left(\int_{t_q^*=1}^{T_q^*} \left[\frac{\varrho}{\varpi}\right]_q \right) + G_{Cashq}^{NPV}\{t_q^*\} \quad \{\forall q\} \tag{3.242}$$

$$\varrho_q = \chi_q\left(\ddot{G}_{LNG} + \dot{E}_{xDP}\right) \tag{3.243}$$

The PI was subsequently determined as the proportion of G_{LNG}^{NPV} to the total CAPEX $\left(\hat{F}_{EX}^{TC}\right)$ (Equation 3.44).

$$P_{LNG}^{PI} = \frac{G_{LNG}^{NPV}}{\hat{F}_{EX}^{TC}} \tag{3.244}$$

(5) Discounted payback period

The payback period $\left(t_{Back}^{Pay}\right)$ of the investment was determined as the operation time in which the total value of discounted periodic cash flows equaled the CAPEX (Equation 3.245).

$$t_{Back}^{Pay} = t^* \quad \left\{\hat{F}_{EX}^{TC} t^* = G_{Cash}^{NPV}\right\} \tag{3.245}$$

(6) Return on investment

The ROI (P_{ROI}) of the venture was obtained as an annual value. it was determined from the division of the non-discounted profits $\left(G_{LNG}^{NDisc}\right)$ [Equations 3.246-3.247] with the non-discounted integrated values of the sum of all periodic expenses incurred on the project (σ). The components of σ include the periodic expenses incurred on Capital investments $\left(\dot{F}_{EX}^{C}\right)$ and the periodic operational expenses (less depreciation) $\left(\dot{E}_{xD}^{Less}\right)$ [Equation 3.248].

$$P_{ROI} = \frac{G_{LNG}^{NDisc} f_{Yr}^{POP}}{\left[\left(\int_{t=t^*}^{t=T^*} \sigma dt\right) + C_{Inv}^{Tot}\{t = t^*\}\right] t^*} \quad \{t^* \geq 0; t^* mod f_{Yr}^{POP} = 0\} \tag{3.246}$$

$$G_{LNG}^{Disc} = \left(\int_{t=t^*}^{t=T^*} \left[C^{LNG} \dot{V}_{LNG}^{shipped} f_{LNG}^{mmBTU} - \dot{C}_{LCC}^{Tot}\right] dt\right) + G_{LNG}^{Disc}\{t = t^*\} \tag{3.247}$$

$$\sigma = \left(\dot{F}_{EX}^{C} + \dot{E}_{xD}^{Less}\right) \tag{3.248}$$

(7) The Breakeven Quantity and Breakeven Period

The breakeven period $\left(t_{Even}^{Break}\right)$ was taken as the LNG operation time in which the total revenue from the venture equals the total investment $\left(C_{Inv}^{Tot}\right)$ [Equation 3.249]. The breakeven point (BEP) $\left[V_{Even}^{Break}\right]$ on the other hand, was estimated as the total volume of LNG already shipped/sold at the time when the breakeven $t_{Even}^{Break}$is reached (Equation 3.250).

$$t_{Even}^{Break} = t^* \qquad \{G_{Rev}^{Tot} = C_{Inv}^{Tot}\} \tag{3.249}$$

$$V_{Even}^{Break} = V_{LNG}^{shipped} = V_{Trnst}^{Ship} + V_{delvrd}^{Ship} \qquad \{G_{Rev}^{Tot} = C_{Inv}^{Tot}\} \tag{3.250}$$

Where:

$$C_{Inv}^{Tot} = \hat{F}_{EX}^{TC} t^* + E_{xD}^{Less} \tag{3.251}$$

$$\varpi = \left(1 + \left[\frac{r^{Disc}}{f_{Yr}^{POP}}\right]\right)^{t^*} \tag{3.252}$$

$$\varpi_q = \left(1 + \left[\frac{r^{Disc}}{f_{Yr}^{POP}}\right]\right)^{t_q^*} \tag{3.253}$$

3.11 Computer Program Development

As a result of the numerous dynamic quantitative relations that make up the model, analysing each of the equations towards obtaining closed-form solutions can be quite cumbersome and time-consuming. Also, due to the complexity of the interactions between the quantities, it may be difficult from obtaining closed-form solutions using manual analytical techniques.

In that regard, the SD-LNG-LCC equations were converted to VENSIM program codes and added as sub-routines to equation tabs created in the VENSIM simulator to correspond with each of the formulated quantities. The programming language utilised was VENSIM compatible C language. The use of the programming language was necessary because the current version of VENSIM is compatible with computer programs that are written in C only.

Figure 3.18 shows a high level flow chart of the implementation of the model in VENSIM. The program is essentially started by entering all the input data required for the executing the LNG LCC analysis for a desired plant. Subsequently, the program then estimates the CAPEX that is required for the project based on the plant capacity input information provided. Once this is achieved, the program checks to ascertain the availability of the capital to fund the CAPEX. If the fund is unavailable, the program terminates. Otherwise, the VENSIM LNG LCC simulation process is activated such that activities at operations, maintenance, equipment supplies and economic analysis are executed simultaneously until completion.

3.12 Model Performance Analysis

On the completion of the development of the SD-LNG-LCC model, its performance was investigated by applying it to real-case LNG operating system data.

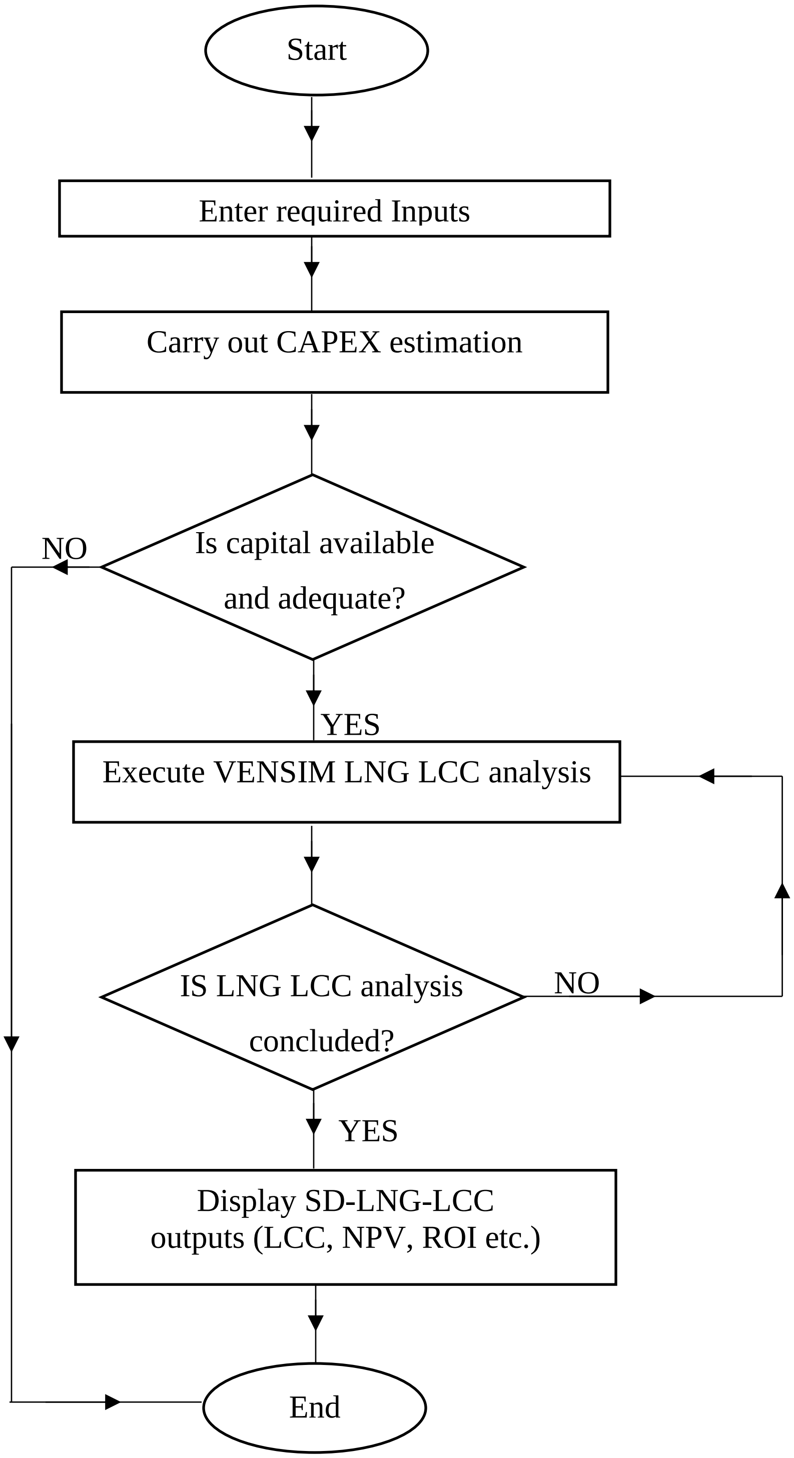

Figure 3.18: High level flow chart of the computer program development for the implementation of the SD-LNG-LCC

However, before the application procedure was undertaken, there was a need to estimate several input parameters that were specific to the system to which the model was being applied. The applied model outcomes were subsequently validated to establish that its performance was as expected. Following this, an evaluation of the LNG operating system's cost and economic performance drivers was done. Furthermore, scenario analysis was also carried out on the applied system to determine different conditions of the input that allowed for improved benefits or losses as the case may be.

3.12.1 Model application

The SD-LNG-LCC model was used to analyse the real-time LNG operations data of an LNG firm that operates in West Africa. For this study, the studied firm will be referred to as the LNGFWA. The model's functionality is dependent on multiple input parameters and as such to ensure its applicability to the real system that was studied these inputs needed to be defined.

Data on the LNGFWA operations spanning a period of twenty-one years (1999-2019) was collected from secondary sources. The inputs were the costs of the base and expansion projects, their corresponding design capacities and the years in which each project became operational, the cost of ships and jetties owned by the organisation for LNG transportation, the stock gas purity, the total annual stock gas supplied the firm and the corresponding expenses incurred, the organisations annual revenue, Infrastructure, annual unit sale prices of the firms LNG to various on-spot and long term contract buyers, and the turbine ratings. Table 3.4 shows the quantities for which data was collected and the sources from which they were gotten.

Some of the sourced information was directly deployed in different capacities as inputs into the SD-LNG-LCC or as test quantities during model performance evaluation activities.
However, others could only be defined based on derivations from the interactions of other inputs. This section discusses the methods, procedures and quantities that were used for estimating the derived input quantities. In addition, the model evaluation procedures are also discussed.

Table: 3.4 Data quantities collected and used for the SD-LNG-LCC parameter estimation and their sources

SN	Data Quantity	Source of Collection
	i. Costs of the base (Greenfield) project ii. Cost of expansion (Brownfield) projects iii. Plant Design capacities for projects Project start-off year iv. Number of ships and jetties owned by the organisation and corresponding costs v. Annual revenue vi. Infrastructure	(Nigerian Liquefied Natural Gas, 2019; NS Energy, 2019; Nigerian Liquefied Natural Gas, 2020)
	Feed gas purity	(Department of Energy, 2013)
	Total annual feed gas supplied to the firm	(Department of Petroleum Resources, 2018, 2019)
	Unit LNG sale prices	(Kar, 2019; World Bank, 2022)
	Liquefaction equipment specifications	(Meher-Homji *et al.*, 2007; Omar, 2016)
	LNFGWA Spot and contract sales and buyers per period	(International Gas Union, 2012a, 2013, 2014, 2015, 2017, 2018, 2019, 2020)
	Sea route distances of LNFGWA loading port to spot and contract buyers' destination ports and their corresponding daily port fare estimates	(Marine Online, 2022; Ports.com, 2022)
	Insurance cost and ship brokerage charges	(Arabian Business, 2011; Rogers, 2018)

3.12.2 Estimation of model parameter values

Twenty-six of the latter type of input parameters were identified. These were grouped in relation to CAPEX, OPEX, production and maintenance-related activities (Table 3.5). This section describes the methods that were used in defining the parameters.

3.12.2.1 CAPEX component parameter estimation

(1) Greenfield and Brownfield unit design costs

These $\left(C_{Dsgnj}^{UCap}\right)$ were estimated as the mean of the respective periodic CAPEX per MTPA $\left(\dot{C}_{jn}^{Cexptd}\right)$ expected to be made on the design of each component, expressed in terms of the marginal plant capacity acquired by $\left(J_{jn}^{exptd}\right)$ (Equation 3.254).

Concerning the case study, the number of periodic CAPEX for Greenfield and brownfield projects of the LNGFWA, the corresponding marginal plant design capacities $\left(J_{jn}\right)$ and CAPEX $\left(\dot{F}_{EXj}^{C}\right)$ were deployed to obtain C_{DsgnG}^{UCap} and C_{DsgnB}^{UCap} respectively.

$$C_{Dsgnj}^{UCap} = \left[\sum_{n=1}^{N_j}\left(\frac{\dot{C}_{jn}^{Cexptd}}{J_{jn}^{exptd}}\right)\right]N_j^{-1} \qquad \{\forall j;\ j: G, B; n: 1,2,3, \dots, N_j\} \qquad (3.254)$$

(2) CAPEX component cost estimation

The unit CAPEX components for the LNG plant $\left(C_{jk}^{UCap}\right)\{k: Own, EPm, E, M, C\}$ were determined as the proportion $\left(f_{jk}^{UCap}\right)$ of C_{Dsgnj}^{UCap} expected to be expended on CAPEX component k in the design and implementation of the LNG plant (Equation 3.255).

$$C_{jk}^{UCap} = f_{jk}^{UCap} C_{Dsgnj}^{UCap} \qquad (3.255)$$

Where f_{jk}^{UCap} is the fraction of CAPEX envisaged for cost element k of project type j.

In estimating f_{jk}^{UCap} it was assumed that except for construction $\left(C_{jC}^{UCap}\right)$, each cost component k of project type j was approximately equal in value.

Table 3.5: Model input parameters estimated via other derived inputs

SN	Project Activity	Description	Symbol	Dimension
1	CAPEX	Bulk Material Cost Per Unit BPDC	C_{BM}^{UCap}	$\$/MTPA$
2		Bulk Material Cost Per Unit GPDC	C_{GM}^{UCap}	$\$/MTPA$
3		Construction Cost Per Unit BPDC	C_{BC}^{UCap}	$\$/MTPA$
4		Construction Cost Per Unit GPDC	C_{GC}^{UCap}	$\$/MTPA$
5		Engineering and Project Management Cost per Unit BPDC	C_{BEpm}^{UCap}	$\$/MTPA$
6		Engineering and Project Management Cost per Unit GPDC	C_{GEpm}^{UCap}	$\$/MTPA$
7		Equipment Cost Per Unit BPDC	C_{BE}^{UCap}	$\$/MTPA$
8		Equipment Cost Per Unit GPDC	C_{GE}^{UCap}	$\$/MTPA$
9		Owners Cost Per BPDC	C_{BOwn}^{UCap}	$\$/MTPA$
10		Owners Cost Per GPDC	C_{GOwn}^{UCap}	$\$/MTPA$
11	OPEX	Periodic OPEX Budget	$\hat{B}_{EX}^{O}$	$
12		OPEX elements Funding Factor	$**K_{i}^{FF}$	Dmnl
13		Periodic OH Cost	C_{OH}^{O}	$\$/Month$
14		LNG Cost Per Shipping Trip	$C_{Ship}^{ShipLNG}$	$
16	Production	LNG Stock Price (Gas)	C_{LNG}^{Gas}	$\$/cm^3Gas$
17		Plant Operation Bottleneck Factor	K_{OBN}^{P}	$Dmnl$
18		Customer Order (CO)	V^{co}	m^3
19		Production Workforce Workrate	L_{prod}^{WRate}	$People/m_{gas}^3$
20	Maintenance	CM/PM Intervention Duration for E_k	t_{CmPmk}^{IDur}	$Month$
21		CM/PM Total Costs Per Intervention	C_{CPm}^{TotInt}	$
22		CM/PM Total Periodic Maintenance Expense per Intervention	C_{xCPm}^{MTot}	$\$/Month$
23		CM/PM Maintenance Man-hour Required for E_k	t_{CmPmk}^{WRqrd}	$PeopleMonth$
24		Number of Maintenance Workers Request for E_k	W_{Mtcek}^{Rqst}	$People/Month$
25		Periodic Material Usage Rate	$\ddot{M}_{Mat}^{Usage}$	$\$/hour$
26		TTPM Threshold for E_k	t_{TTPmk}^{Thr}	$Month$

Table 3.5 (continued): Model input parameters estimated via other derived inputs

SN	Project Activity	Description	Symbol	Dimension
29	Maintenance	TA Total Maintenance Costs per Intervention	C_{Ta}^{PerInt}	\$
30		TA Maintenance Man-hour Required for E_k	t_{Tak}^{Wrqrd}	$Month$
31		TA Total Periodic Maintenance Expense per Intervention	C_{xTa}^{MTot}	$\$/Month$
32		Weibull Shape parameter for E_k	β_{Ek}	$Dmnl$
33		Weibull Scale parameter for E_k	η_{Ek}	$Month$

**: i: $Mtce, FG, FuG, Lab, OH, TRPN$

f_{jk}^{UCap} $\{k \neq C\}$ were subsequently estimated by observing the residual value $\left(\Delta_{k}^{UCap}\right)$ of the difference between C_{Gk}^{UCap} and C_{Bk}^{UCap} by subtracting a value δ_{ki} from an assumed CAPEX component fraction value $\left(f_{Gki}^{*UCap}\right)$ (Equation 3.256).

$$\left(f_{Gki}^{*UCap} - \delta_{ki}\right)C_{DsgnG}^{UCap} - \left[f_{Bki}^{*UCap} C_{DsgnB}^{UCap}\right] = \left|\Delta_{ki}^{UCap}\right| \qquad \{k \neq C\} \quad (3.256)$$

Where,

$$f_{Bki}^{*UCap} = \frac{\left(f_{Gki}^{*UCap} - \delta_{ki}\right)C_{DsgnG}^{UCap}}{C_{DsgnB}^{UCap}} \quad (3.257)$$

f_{jk}^{UCap} was taken as $\left(f_{Gki}^{*UCap} - \delta_{ki}\right)$ and f_{Bki}^{*UCap} respectively by searching for a value of δ_{ki} that produced the minimum $\left|\Delta_{ki}^{UCap}\right|$ value. The f_{Gki}^{*UCap} $\{k \neq C\}$ were adopted. The LNG CAPEX component fraction estimates as provided by (Songhurst, 2018) were adopted as f_{Gki}^{*UCap} $\{k \neq C\}$ values.

The cost fraction for construction was finally determined using Equation 3.258.

$$f_{jC}^{*UCap} = 1 - \left[\sum_{k} f_{jk}^{UCap} \quad \{k \neq C\}\right] \qquad \{\forall j\} \quad (3.258)$$

3.12.2.2 OPEX component parameter estimation

(1) Periodic overhead cost

The periodic overhead cost (C_{OH}^{O}) refers to the estimated value of OPEX components that are related to LNG processes but were not explicitly captured in the study. Such OPEX components include the costs of consumables, tugs, jetties, and insurance. The C_{OH}^{O} was estimated as the product of the sum of the OPEX (less the values of the feed gas and depreciation) and the overhead/other Expenses Factor (f_{OH}^{O}) [Equation 3.259]. The f_{OH}^{O} was determined as a fraction of the total OPEX fraction.

The f_{OH}^{O*} in Equation 3.259 is the overhead estimate when all OPEX elements are summed up to 100 percent. Based on Songhurst (2018) recommendation, the value of 13 percent was adopted as f_{OH}^{O*}.

$$C_{OH}^{O} = E_{xLess}^{FGDp} f_{OH}^{O} = \frac{(\dot{E}_{xMtce}+\dot{E}_{xFuG}+\dot{E}_{xLab}+\dot{E}_{CF}^{Intrst}+\dot{E}_{xTrpn}) f_{OH}^{O*}}{(100-f_{OH}^{O*})} \quad (3.259)$$

(2) Periodic OPEX budget

The periodic OPEX budget $(\hat{B}_{EX}^{O})$ as an input quantity was estimated by first running the model (with all other inputs duly defined) under a limitless fund availability scenario. At the end of this run, the total OPEX values (C_{EXi}^{TPrev}) of the respective OPEX elements (i) determined from the periodic OPEX for each element $C_{EXit^*}^{Prev}$ and recorded. The $\hat{B}_{EX}^{O}$ was then estimated as the sum of $\hat{B}_{EXi}^{O}$, that is the sum of the single period value of C_{EXi}^{TPrev}. (Equations 3.260 and 261).

$$\hat{B}_{EX}^{O} = \sum_{i=1}^{5} \hat{B}_{EXi}^{O} \quad (3.260)$$

$$\hat{B}_{EXi}^{O} = C_{EXi}^{TPrev} P_L^{-1} = \left[\sum_{t^*=1}^{T^*} C_{EXit^*}^{Prev}\right] P_L^{-1} \qquad \{\forall i\} \quad (3.261)$$

Where, $\{i = 1, 2, 3, 4, 5,6\}$ corresponds to (Mtce, FG, FuG, Lab,OH and Trpn) respectively.

(3) OPEX elements Funding Factor

Funding factor (K_i^{FF}) are considered as the indices that are deployed towards the determination of the proportion of the total available funds to be allocated for each OPEX element i $\{i: Mtce, FG, FuG, Lab, OH, Trpn)$. The K_i^{FF} was considered a necessity for effective funds and allocation during the operational phase of the project. It is worth noting that the decision to allocate resources for various operational expenditures is unique to and varies from one organisation to another. In this study, K_i^{FF} was obtained using a two-step approach. The first step was achieved by running the model under the limitless fund availability scenario to determine the expenses incurred for each of the cost elements (C_{EXi}^{Prev}). In the second step, K_i^{FF} were then determined as the ratios of the sum of C_{EXi}^{Prev} (Equation 3.262)

$$K_i^{FF} = \frac{C_{EXi}^{Prev}}{\hat{B}_{EX}^{O}} \qquad \{\forall i\} \quad (3.262)$$

It is also worth noting that Equations 259 – 262 cover all LNG activities including delivery costs.

(4) LNG cost per shipping trip

The cost of transporting produced LNG to the buyers was estimated based on the shipping trips made. To this end, an adaptation of the Rogers (2018) estimation method was deployed. $C_{Trpn}^{ShipLNG}$ was taken as the sum of ship charter rate $\left(C_{Ship}^{Chrt}\right)$, ship fueling cost $\left(C_{Ship}^{Fuel}\right)$, port charges $\left(C_{Ship}^{Port}\right)$, insurance cost $\left(C_{Ship}^{Insr}\right)$ and brokerage charges $\left(C_{Ship}^{Brkg}\right)$ [Equation 3.263].

$$C_{Trpn}^{ShipLNG} = C_{Ship}^{Chrt} + C_{Ship}^{Fuel} + C_{Ship}^{Port} + C_{Ship}^{Insr} + C_{Ship}^{Brkg} \qquad (3.263)$$

The methods used in estimating $C_{Trpn}^{ShipLNG}$ are discussed next.

A. Ship charter cost

Regarding the determination of C_{Ship}^{Chrt}, consideration was given to the regular variances in the daily rates for long-term and spot charters as well as variances in the charter rates based on different ship propulsion systems of typical carriage volume that range between 130000-180000m^3. Thus, as described in equation 3.264, C_{Ship}^{Chrt} was obtained in any operation period was taken as the grand sum of the summed up daily charter rates for different propulsion systems (q) available to the firm for long-term charter (L) and spot charter (S) respectively.

$$C_{Shipt^*}^{Chrt} = \sum_{q=1}^{Q}\left(f^{Avail}C^{Chrt}\right)_{ShipqLt^*} + \sum_{q=1}^{Q}\left(f^{Avail}C^{Chrt}\right)_{ShipqSt^*} \qquad \{\forall t^*\} \qquad (3.264)$$

Where f_{ShipqL}^{Avail} and f_{Shipqs}^{Avail} are the fractions of vessels of propulsion system type q available to the organisation for long-term charter and spot charter respectively.

$$\sum_{q=1}^{Q} f_{ShipqLt^*}^{Avail} = 1 \text{ and } \sum_{q=1}^{Q} f_{ShipqSt^*}^{Avail} = 1 \qquad (3.265)$$

B. Fuel cost

The cost of fueling the shipping vessels $\left(C_{Ship}^{Fuel}\right)$ was estimated in values of tonnage usage per day. Ship displacement and speed were the factors that were considered to affect fuel consumption in the study. Regarding this consideration, the Barrass (2004) ship heavy fuel oil (HFO) consumption model was adapted to estimate the daily amount of LNG required as fuel by the shipping vessel (Equation 3.266).

$$A_{LNGq}^{Req} = \frac{\overline{D}^{\frac{2}{3}}\overline{V}^{3}K_{HFO}^{HV} \times 10^{-4}}{595.407\varepsilon_{shipq}^{fuel*}K_{BTU}^{Joule}} \qquad (3.266)$$

Where $\overline{D}$ and $\overline{V}$ are the average expected displacement and speed for all vessels available to the firm for LNG delivery. The K_{HFO}^{HV} is the heating value for HFO (41800 J/Tonne) while K_{BTU}^{Joule} is the Joule value equivalence of 1BTU (1055J/BTU).

In its original form, equation (3.266) is representative of the fuel consumption for a steam-type propulsion engine ($q = STe$), thus the relative fuel efficiency value is taken as unity. However, in adapting it to obtain fuel consumption for the dual fuel diesel electric engine ($q = DFDEe$), $\varepsilon_{shipq=DFDEe}^{fuel*}$ was taken as the ratio of the actual fuel efficiencies of the STe and $DFDEe$ (Equation 3.267)

$$\varepsilon_{shipq}^{fuel*} = \begin{cases} 1 & \{q = STe\} \\ \dfrac{\varepsilon_{shipSTe}^{fuel}}{\varepsilon_{shipDFDEe}^{fuel}} & \{q = STe\} \end{cases} \qquad (3.267)$$

The actual fuel efficiencies for the steam propulsion engine $\left(\varepsilon_{shipSTe}^{fuel}\right)$ and the DFDE engine $\left(\varepsilon_{shipDFDEe}^{fuel}\right)$ were taken as 29 and 42% respectively.

Basing the periodic fuel consumption requirement on the degree of availability of vessels with the two propulsion systems considered, the LNG fuel requirement for each vessel was estimated using equation 3.268.

$$A_{LNGt^*}^{Req} = f_{STet^*}^{Avail}A_{LNG(STe)}^{Req} + \left(1 - f_{STet^*}^{Avail}\right)A_{LNG(DFDEe)}^{Req} \qquad (3.268)$$

The prioritised fuel source for the vessel is the BOG rate volume $\left(\dot{V}_{BOG}\right)$ given off by the LNG storage tanks while the vessels are on route to delivery. However, the BOG may not always be adequate and as such, has to be supplemented if need be by the use of heavy oil variants such as the HFO. Thus the amount of fuel consumed by a shipping vessel per trip $\left(A_{Tript^*}^{Fuel}\right)$ as a function of the ship round trip travel distance $\left(D_{Trip}^{RShip}\right)$ is described by equation (3.269).

$$A_{Tript^*}^{Fuel} = \begin{cases} A_{LNGt^*}^{Req} D_{Trip}^{RShip} & \{\dot{V}_{BOG} \geq A_{LNGt^*}^{Req}\} \\ \dot{V}_{BOGt^*} + K_{HFO}^{LNG}\left(A_{LNGt^*}^{Req} D_{Travel}^{Ship} - \dot{V}_{BOGt^*}\right) & \{Otherwise\} \end{cases} \tag{3.269}$$

K_{HFO}^{LNG} is the factor of conversion of 1 Tonne of LNG to HFO tonnage equivalence.

C_{Ship}^{Fuel} was then estimated by multiplying $A_{Tript^*}^{Fuel}$ by the periodic cost per tonne of the respective fuel types (Equation 3.270).

$$C_{Shipt^*}^{Fuel} =$$

$$\begin{cases} C_{Tont^*}^{LNG} A_{LNGt^*}^{Req} D_{Tript^*}^{RShip} & \{\dot{V}_{BOG} \geq A_{LNGt^*}^{Req}\} \\ C_{Tont^*}^{LNG} \dot{V}_{BOGt^*} + C_{Tont^*}^{HFO} K_{HFO}^{LNG}\left(A_{LNGt^*}^{Req} D_{Tript^*}^{RShip} - \dot{V}_{BOGt^*}\right) & \{Otherwise\} \end{cases} \tag{3.270}$$

D_{Trip}^{RShip} was determined by identifying all the spot and long-term contract buyers of the organisation’s product and classifying them into seven groups based on similarity in their geographical locations. The buyers' group names G $(G: 1,2,3, \dots, 7)$, are Europe, North America, South America, Japan-Korea Market, South Asia, Middle East and Africa. The fraction of LNG sales made by the firm to the countries in each of the buyer groups within the study period $\left(f_{FWAGt^*}^{TLNG}\right)$ was then determined from the volume of sales made by the firm to each of the buyer groups in each period t^*.

Similarly, the average distances (in nautical miles) from the loading port of the LNGFWA to the ports of the buyer groups D_{TripG}^{RShip} were also computed from secondary data sources (See Appendix E for details). D_{Trip}^{RShip} in each operational period was subsequently estimated as the product of f_{FWAG}^{TLNG} and D_{TripG}^{RShip} (Equation 3.271).

$$D_{Tript^*}^{RShip} = \sum_{G=1}^{7} f_{FWAGt^*}^{TLNG} D_{TripGt^*}^{RShip} \qquad (3.271)$$

C. Port Charges

In estimating the port charges $\left(C_{Ship}^{Port}\right)$ incurred by the firm, consideration was given for the duration of shipment loading (t_{Load}^{Port}) and unloading (t_{Unload}^{Port}) at the LNG shipment at the source and destination ports respectively. Time was also allocated to docking activities at the source port (t_{Dock}^{Port}) with regard to returning ships. Thus, the port charges at different periods $C_{Shipt^*}^{Port}$ were estimated as the aggregate of the estimated port charges from the point of product loading to delivery (Equation 3.272).

$$C_{Shipt^*}^{Port} = C_{Source}^{Port}[t_{Load}^{Port} + t_{Dock}^{Port}] + \sum_{G=1}^{7} f_{FWAGt^*}^{TLNG} C_{DestG}^{Port} t_{UnLoad}^{Port} \qquad (3.272)$$

The values for C_{Source}^{Port} and C_{Dest}^{Port} were obtained from a secondary source (Marine Online, 2022) and are shown in Appendix E. Regarding of t_{Load}^{Port}, t_{UnLoad}^{Port} and t_{Dock}^{Port}, a one-day duration was considered adequate for each quantity for the completion of loading, unloading and docking activities at the respective ports.

D. Insurance cost and ship brokerage charges

Due to the paucity of complete information on the time influence insurance charges for shipping vessels, the partial information on the daily insurance costs for 2011 and 2018 as well as the rate of insurance charge increases between 2000 and 2011 was used in computing C_{Ship}^{Insr} (Equation 3.273) at different operational periods.

$$C_{Shipt^*}^{Insr} = \begin{cases} 709.51(1.075)^{\tau^*} & \{\tau^* \leq 2011\} \\ 1572(1.075)^{\tau^*} & \{Otherwise\} \end{cases} \qquad (3.273)$$

τ^* is the plant operational period expressed in years.

The ship agency and brokerage fee were fixed at two percent of the charter cost as suggested by Rogers (2018).

3.12.2.3 Parameter estimation for production activities

(1) LNG stock price

Based on the feed gas pricing policy framework in which the organisation operates within, the periodic gas stock price $\left(C_{LNGt^*}^{Gas}\right)$ was obtained by dividing the periodic total feed gas payments the organisation made to all its suppliers $\left(C_{FWAt^*}^{Tgas}\right)$ by the total energy in MMBTU from LNG production $\left(V_{FWAt^*}^{TLNG}\right)$ and sales (Equation 3.274).

$$C_{LNGt^*}^{Gas} = \frac{f_{LNG}^{mmBTU} C_{FWAt^*}^{Tgas}}{V_{FWAt^*}^{TLNG}} \qquad \{\forall t^*\} \tag{3.274}$$

(2) LNG sales price

The periodic sales price of liquefied natural gas for the firm $\left(P_{FWAt^*}^{ULNG}\right)$ was determined by the division of the periodic revenue made by the firm by $V_{FWAt^*}^{TLNG}$ (Equation 3.275).

$$P_{FWAt^*}^{ULNG} = \frac{G_{FWAt^*}^{TLNG}}{V_{FWAt^*}^{TLNG}} \qquad \{\forall t^*\} \tag{3.275}$$

(3) Plant bottleneck factor

The plant bottleneck factor $\left(K_{OBNt^*}^{P}\right)$ was estimated by dividing the total process feedstock supplied for production in operation period t^* $\left(V_{FWAt^*}^{Tgas}\right)$ by the corresponding production capacity of the plant at that period (P_{DCt^*}). The relations are shown in Equation 3.276

$$K_{OBNt^*}^{P} = \left[\frac{1}{\gamma f_{LNG}^{Gas}}\left(\frac{V_{FWA}^{Tgas*}}{P_{DC}}\right)_{t^*}\right] \tag{3.276}$$

(4) Customer Order

The customer order made $(V_{t^*}^{co})$ which represents the LNG order made by the customer in operation period t^* was estimated as a fraction of the desired periodic LNG (in $m^3 Time^{-1}$) converted dependent on the natural purity of the feedstock (Equation 3.277).

$$V_{t^*}^{co} = V_{Dt^*}^{LNG} f_{Dt^*}^{LNG} K^{NGC} \tag{3.277}$$

$f_{Dt^*}^{LNG}$ is the fraction of the customer order desired in operation period t^* $\left(f_{Dt^*}^{LNG} \geq 0\right)$

(5) Expected Unit Workforce Production Rate

This quantity represents the amount of production of workers capable of converting one MTPA of feedstock to LNG. W_{prod}^{URate} was estimated as the mean value of all unit workforce production rates of four LNG projects currently in operation as reported by Songhurst (2018).

(6) Plant productivity

The plant productivity (K^{PrC}), plant availability (A_{Plt^*}) and the natural gas purity (K^{NGC}) were considered the most significant bottleneck influencing factors in the liquefaction process. K^{PrC} was determined based on the relation in Equation 3.278 on the condition that the other plant productivity contributions were defined.

$$K_{t^*}^{Prc} = \frac{1}{T^*} \sum_{t^*=1}^{T^*} \frac{E_{Syst^*}^{ConvEff}}{K^{NGC} A_{Plt^*}} \tag{3.278}$$

$E_{Sys}^{ConvEff}$ is the plant's conversion effectiveness and was determined as the ratio of the gas volume equivalent of previously produced and delivered LNG $\left(V_{FWAt^*}^{ProdLNG*}\right)$ and the feedstock volume supplied for production $\left(V_{FWAt^*}^{Tgas}\right)$ less the volume allocated for fuel [Equation 3.279]

$$E_{Syst^*}^{ConvEff} = \frac{V_{FWAt^*}^{ProdLNG*}}{V_{FWAt^*}^{Tgas}\left(1 - f_{Fu}^{Usage}\right)} \qquad \{\forall t^*\} \tag{3.279}$$

The $V_{FWAt^*}^{ProdLNG}$ was gotten by dividing the periodic revenue of the firm $\left(G_{FWAi}^{TLNG}\right)$, by the LNG sale price of that period (Equation 3.280).

$$V_{FWAt^*}^{ProdLNG*} = V_{FWAt^*}^{ProdLNG} f_{LNG}^{Gas} = \frac{f_{LNG}^{Gas} G_{FWAi}^{TLNG}}{P_{FWAt^*}^{ULNG}} \tag{3.280}$$

The A_{Plt^*} was estimated as the ratio of the total equipment downtime $\left(t_{Totsyst^*}^{Downtime}\right)$ and the total equipment utilisation time $\left(t_{Totsyst^*}^{EqUse}\right)$ [Equations 3.281 – 3.285].

$$A_{Plt^*} = \frac{t_{Totsyst^*}^{Downtime}}{t_{Totsyst^*}^{EqUse} + t_{Totsyst^*}^{Downtime}} \tag{3.281}$$

$$t_{Totsyst^*}^{Downtime} = \int_{t=0}^{t^*} \dot{t}_{syst^*}^{Downtime}\, dt \qquad (3.282)$$

$$t_{syst^*}^{Downtime} = \begin{cases} t_{pw}^* & \{\Phi_S = 1\} \\ 0 & \{otherwise\} \end{cases} \qquad (3.283)$$

$$t_{Totsyst^*}^{EqUse} = \int_{t=0}^{t^*} \dot{t}_{syst^*}^{EqUse}\, dt \qquad (3.284)$$

$$t_{syst^*}^{EqUse} = \begin{cases} t_{pw}^* & \{\Phi_S = 1; t^* > 0; (P_L - t^*) > 0\} \\ 0 & \{otherwise\} \end{cases} \qquad (3.285)$$

(8) Production workforce requirement

The production workforce requirement is the expected production workforce required per unit available workload $\left(W_{prod}^{UReqd}\right)$ and reflects the number of person-hours required to convert the cubic meter equivalent of 1 MTPA of feed gas into LNG. Ideally, W_{prod}^{UReqd} as a time-influenced quantity was estimated as the mean of the quotient of the firm's production operation fraction of the total workforce number (W_{LNGFWA}^{P}) and the cubic-meter-gas equivalent of the plant design capacity (P_{DC}) [Equation 3.286].

$$W_{prodt^*}^{UReqd} = \frac{f_{Prod}^{W} W_{LNGFWAt^*}^{P}}{P_{DCt^*} f_{LNG}^{Gas} \gamma} \qquad (3.286)$$

f_{Prod}^{W} is the fraction of the total workforce of the organisation that is dedicated to all work functions except maintenance. Based on Dunn (1999) observation of the workforce constitution of production/manufacturing plants, f_{Prod}^{W} was taken as 0.75.

(9) Workforce wage rate

The wage rate for workers $\left(W_{z}^{Wage}\right)$was taken as a uniform value for all LNG operations (z) that utilised human involvement (z: z = Prod., Mtce.). Based on the payment policy adopted by the LNGFWA, W_{z}^{Wage} was estimated as the sum of periodic wages paid to permanent $\left(W_{zPemnt}^{Wage}\right)$ and contract staff $\left(W_{zCtrct}^{Wage}\right)$ with consideration given to the fraction of permanent (f_{zPemnt}^{W}) and contract (f_{zCtrct}^{W}) employees employed by the firm (Equation 3.287). Based on the relationship between all the quantities considered, Equation 3.287 was subsequently resolved in terms of W_{zPemnt}^{Wage}, f_{zPemnt}^{W} and f_{zct-pt}^{Wage}, which is the fraction of wages paid in relation to W_{zPemnt}^{Wage} and W_{zCtrct}^{Wage} (Equation 3.288).

$$W_z^{Wage} = f_{zPemnt}^{W} W_{zPemnt}^{Wage} + f_{zCtrct}^{W} f_{zCtrct}^{Wage} W_{zCtrct}^{Wage} \quad (3.287)$$

$$W_z^{Wage} = W_{zPemnt}^{Wage}\left(f_{zPemnt}^{W}\left[1 + f_{zct-pt}^{Wage}\right] + f_{zct-pt}^{Wage}\right) \quad (3.288)$$

By adapting information from secondary sources (Andeobu *et al.*, 2005; Itegboje, 2018; Simeon and Daniel, 2018), f_{zPemnt}^{W} and f_{zct-pt}^{Wage} were taken as 0.787 and 0.333 respectively.

3.12.2.4 Parameter estimation for maintenance activities

In order to effectively estimate the inputs of various activities in the liquefaction plant (particularly the maintenance sector) to be able to appreciate their impact on the total system performance, the equipment which play critical roles in LNG production processes were first identified using information from secondary (Meher-Homji *et al.*, 2007; Omar, 2016). Ten of such equipment (of equipment class type *j*) were identified namely Compressors/Expanders $\left(CT_j\right)$, Gas turbine drivers $\left(GTD_j\right)$, Natural gas pre-cooling heat exchangers $\left(PCHE_j\right)$, main cryogenic heat exchangers $\left(MCHE_j\right)$, gas separators $\left(GST_j\right)$, valves $\left(VLV_j\right)$, gas treatment heaters $\left(GTHS_j\right)$, pipes$\left(PPNG_j\right)$, ships and transport vessels $\left(TRPN_j\right)$ and others [sensors, fire/gas detectors, pumps, etc.] $\left(OTHR_j\right)$. In addition, their specifications *vis-à-vis* the desired plant operation requirement were done.

The expected maintenance-related behavioural properties of the equipment obtained from LNG equipment reliability data (SINTEF Industrial Management, 2002; Cunha, 2012) were then used in the estimation of the maintenance cost and operations parameters. The maintenance-related behavioural properties collected include the mean values of, the number of failures ($\bar{\mathcal{F}}_k$), repair times ($\bar{\mathcal{R}}_k$), repair man hours ($\bar{\mathcal{M}}_{CPmk}$, $\overline{\mathcal{M}_{Tak}}$), number of failure modes $\left(N_k^{\mathcal{F}Mode}\right)$, and the failure rates $\left(\bar{\lambda}_k\right)$.

(1) Equipment failure distribution parameters

The equipment distribution failure shape (β_{Ek}) and scale (η_{Ek}) parameters were estimated based on the data covering equipment failure times from secondary sources (Kiriya, 2000;

SINTEF Industrial Management, 2002; Cunha, 2012; Chaplin, 2017). The two-parameter Weibull cumulative density function was adopted for the cumulative failure probability (P_k) prediction for each of the equipment type k (Equation 3.289). Based on practices in the LNG industry which are heavily tilted towards replacement maintenance policy, the Weibull shape parameter (β_k) was set at 1.2 (Exponential distribution) using the study assumption that replaced equipment functionality is always as good as new.

$$P_k = 1 - e^{-\left(\frac{t_{cumk}^{Up}}{\eta_k}\right)^{\beta_k}} \tag{3.289}$$

However, the age effect on equipment functionality based on the hazard bathtub concept (ReliaSoft, 2015) was considered by setting the scale parameter (η_k) to different values concerning the age of the equipment. This was done in terms of its cumulative uptime $\left(t_{cumk}^{Up}\right)$ within the plant life (P_L) as described in Equation 3.290.

$$\eta_k = Int\begin{cases} \eta_k^{\mathrm{E}} & \left\{Early\ Life: t_{cumk}^{Up} \leq 0.15P_L\right\} \\ \eta_k^{\mathrm{U}} & \left\{Useful\ Life: 0.15P_L < t_{cumk}^{Up} \leq 0.75P_L\right\} \\ \eta_k^{\mathrm{W}} & \left\{Wearout\ Life: t_{cumk}^{Up} > 0.75P_L\right\} \end{cases} \tag{3.290}$$

η_k^E, η_k^U and η_k^W are the respective equipment Weibull scale parameter in the phases of its early, useful and wear-out life respectively. η_k^E, η_k^U and η_k^W were determined based on different t_{cumk}^{Up} values (Equations 3.291-3.293).

$$\eta_k^{\mathrm{E}} = \eta_k \left\{t_{cumk}^{Up} = t_{TTPmk}^{Thr}\right\} \tag{3.291}$$

$$\eta_k^{\mathrm{U}} = \eta_k \left\{t_{cumk}^{Up} = 0.8t_{TTPmk}^{Thr}\right\} \tag{3.292}$$

$$\eta_k^{\mathrm{W}} = \eta_k \left\{t_{cumk}^{Up} = 1.2t_{TTPmk}^{Thr}\right\} \tag{3.293}$$

(2) Mean time to maintenance intervention threshold

The TTPM $\left(t_{TTPmk}^{Thr}\right)$ and TTTA $\left(t_{TTTak}^{Thr}\right)$ maintenance is the time interval adopted by organisations before PM and TA maintenance interventions are undertaken. Regarding TA maintenance, TTTA was estimated by adopting a five-year cycle based on Lawrence (2012) suggestion. However, t_{TTPmk}^{Thr} was estimated as an equipment-specific parameter using a modified form of the Weibull Failure probability relation Equation 3.294.

$$t_{TTPmk}^{Thr} = \frac{1}{\bar{\lambda}_k}[-Ln(1-P_k)]^{\frac{1}{\beta_k}} \qquad (3.294)$$

In this case, P_k was set to a value of 0.75. Thus the TTPM for each piece of equipment represents a value determined from anticipating the probability of equipment failure but carrying out PM intervention at a time that corresponds to a 75% probability of the equipment failing.

(3) Maintenance policy-based equipment intervention duration

The intervention duration refers to the specific repair time times for corrective/preventive (t_{CmPmk}^{IDur}) and turn-around maintenance (t_{Tak}^{IDur}) for E_k as deployed in the study. The t_{CmPmk}^{IDur} was taken as $\bar{\mathcal{R}}_k$ which is the average repair time for a unit failure mode. The t_{Tak}^{IDur} on the other hand involves the complete overhaul of equipment, a situation which involves the maintenance of all types of failure modes that E_k has previously manifested. In that regard, t_{Tak}^{IDur} was taken as the product of $\bar{\mathcal{R}}_k$ and $N_k^{\mathcal{F}Mode}$ (Equation 3.295).

$$t_{Tak}^{IDur} = \bar{\mathcal{R}}_k N_k^{\mathcal{F}Mode} \qquad (3.295)$$

(4) Maintenance policy based total expected cost per maintenance intervention

The total expected cost per maintenance intervention was estimated in terms of CM/PM (C_{CPm}^{TotInt}) and TA maintenance (C_{Ta}^{TotInt}). Both of these parameters were obtained as the sum of the expected CM/PM or TA maintenance cost ($C_{CPmk}^{PerInt}, C_{Tak}^{PerInt}$ as the case may be) of all E_k considered. In achieving this, an estimate of the purchase cost for equipment unit $\left(C_{kRef}^{UP}\right)$ was first obtained (equation 3.296). This was done by determining the cost of the equipment time in a base year (C_{kbase}^{UP}) and correcting it to a reference year using the chemical engineering plant cost index [CEPCI] (Jenkins, 2017)

$$C_{kRef}^{UP} = C_{kbase}^{UP}\left[\frac{I_{CEPSI}\{t_{Ref}\}}{I_{CEPSI}\{t_{base}\}}\right] \qquad (3.296)$$

The C_{kbase}^{UP} estimation for E_k was done by classifying the different equipment types into three groups. The cost of equipment belonging to each group was then estimated using an estimation technique that is unique to each group based on the adaptation of estimates provided by the sources consulted. Table 3.6 shows the different groups of equipment and how their costs were estimated. Subsequently, by adapting the concepts of (Lawrence, 2012) and Pflueger (2005), $C_{CPmt^*}^{PerInt}$ and $C_{Tat^*}^{PerInt}$ at any operation period t^*, were estimated as the sum of the costs of repair and lubrication for each piece of equipment corrected for inflation $\left(f_{t^*,t_{ref}}^{infl}\right)$ [equations 3.297 and 3.298].

$$C_{Tat^*}^{PerInt} = \sum_{k=1}^{K} C_{Takt^*}^{PerInt} = \sum_{k=1}^{K} \frac{\gamma_k\left(C_{Mpurk}^{Tot} + \beta_k C_{MLub}^{Tot}\right)}{N_{Tak}^{Int} f_{t^*,t_{ref}}^{infl}} \tag{3.297}$$

$$C_{CPmt^*}^{PerInt} = \sum_{k=1}^{K} C_{CPmkt^*}^{PerInt} = \sum_{k=1}^{K} \frac{\gamma_k\left(C_{Mpurk}^{Tot} + \beta_k C_{MLub}^{Tot}\right)}{N_{CPmk}^{Int} f_{t^*,t_{ref}}^{infl}} \tag{3.298}$$

C_{Mpurk}^{Tot} is the total expected maintenance cost for each piece of equipment based on the cost of purchase of the equipment. C_{Mpurk}^{Tot} was estimated as the product of the number of equipment units $\left(N_k^{Unit}\right)$, the unit equipment purchase-based maintenance cost rate $\left(\dot{C}_{Mpurk}^{Unit}\right)$, plant design capacity (P_{DC}) and expected plant life (P_L) [Equations 3.299 and 3.300].

$$C_{Mpurk}^{Tot} = N_k^{Unit} \dot{C}_{Mpurk}^{Unit} P_L P_{DC,t^*} \tag{3.299}$$

$$\dot{C}_{Mpurk}^{Unit} = \alpha_k C_{gk}^{MTPA} \tag{3.300}$$

α_k are the maintenance cost fractions of the expected equipment cost per MTPA $\left(C_{gk}^{MTPA}\right)$. In line with the 3-6% purchase cost per annum estimate suggested by Walia *et al.* (2010), α_k was taken as a value of 5% per annum. C_{MLub}^{Tot} is the total expected cost of maintenance attributed to lubrication for all equipment and was considered a function of the expected fuel cost $\left(C_{Fuel}^{exptd}\right)$. C_{MLub}^{Tot} was estimated as the product of the lubrication cost fraction $\left(f_{MLub}^{Tot}\right)$, fuel usage factor $\left(f_{Fu}^{Usage}\right)$, LNG price $\left(C^{LNG}\right)$ and the energy equivalence of the desired LNG stock $\left(V_D^{LNGge}\right)$ [Equation 3.301].

$$C_{MLub}^{Tot} = f_{MLub}^{Tot} C_{Fuel}^{exptd} = f_{MLub}^{Tot} f_{Fu}^{Usage} C^{LNG} V_D^{LNGge} \tag{3.301}$$

Table 3.6: LNG Equipment grouped based on their base year cost estimation method

Group	Equipment (k)	Cost Estimation Method
1	Compressors/expanders, Multi-flow, low-temperature heat exchangers, Main cryogenic heat exchangers, Gas Separators, Gas turbine drivers, Gas treatment heaters and Valves.	The estimation method employed here involved the determination of the cost of each unit of the equipment per 4.5 MTPA for a C3MR liquefaction technology using data provided by (Dirk, 2009; Omar, 2016). The t_{base} used for estimating GTD_j and $GTHS_j$ cost was 2009, while 2012 was adopted for the others. The cost per unit MTPA (C_k^{MTPA}) was gotten as $$C_{1k}^{MTPA} = \frac{C_{kRef}^{UP}}{4.5}$$ Where: C_{1k}^{MTPA} is the cost of E_k per unit MTPA (in \$/MTPA), $k = 1, 2,3 \dots, n$(all equipment in this group)
2	Ships/LNG delivery equipment	The equipment in this group were estimated from the LNGFWA organisation's records and publications. $C_{TRPNRef}^{UP}$ was estimated as the sum of the cost of the delivery equipment in the purchase year d corrected for inflation to the t_{ref} $f_{d,t_{ref}}^{infl}$ $$C_{TRPNRef}^{UP} = \sum_{d=1}^{D} C_{TRPNd}^{UP} f_{d,t_{ref}}^{infl}$$ C_{2k}^{MTPA} was subsequently determined as the ratio of $C_{TRPNRef}^{UP}$ and the LNGFWA's plant design capacity in t_{ref}. $$C_{2k}^{MTPA} = \frac{C_{TRPNRef}^{UP}}{P_{DCt_{ref}}}$$

Table 3.6 (Continued): LNG Equipment grouped on the basis of their base year cost estimation method

Group	Equipment ($\boldsymbol{k}$)	Cost Estimation Method
3	Piping, Others (Sensors, fire/gas detectors, pumps, other Instrumentation and control, electrical equipment and related materials	These were obtained as fractions of the total purchased equipment cost (Omar, 2016) as indicated by the following equation $$C_{3k}^{MTPA} = q(k)\left(\sum_{i=1}^{n} C_{1k}^{MTPA} + \sum_{i=1}^{m} C_{2k}^{MTPA}\right)$$ Where: n, m: Number of equipment in groups 1 and 2 respectively; $q(k: PPNG) = 0.35$; $q(k: OTHR) = 0.2$

β_k are the lubrication cost fractions for E_k and represent the cost incurred from equipment lubrication. β_k was determined with consideration given to power (Fuel dependent) equipment only, that is the compressors and gas turbine drivers (Equation 3.302).

$$\beta_k = \frac{R_k^{Power}}{\left(R_{CT_j}^{Power} + R_{GTD_j}^{Power}\right)} \qquad \{k: CT_j, GTD_j\} \tag{3.302}$$

γ_k is the turnaround maintenance fraction of the total expected maintenance cost and was taken as 40% for any equipment considered.

N_{Tak}^{Int} and N_{Pmk}^{Int} are the numbers of TA maintenance and PM interventions expected to be undertaken during the life cycle of the plant. N_{Tak}^{Int} was estimated as the integer value ratio of P_L and the expected time to TA maintenance threshold $\left(t_{TTTak}^{Thr}\right)$ [Equation 3.303].

$$N_{Tak}^{Int} = int\left(\frac{P_L}{t_{TTTak}^{Thr}}\right) \tag{3.303}$$

N_{Pmk}^{Int} on the other hand was estimated as the positive difference between P_L and the total TA duration $(N_{Tak}^{Int} t_{Tak}^{IDur})$ divided by the TTPM Threshold $\left(t_{TTPmk}^{Thr}\right)$ [Equation 3.304].

$$N_{Pmk}^{Int} = int\left(\frac{P_L - (N_{Tak}^{Int} t_{Tak}^{IDur})}{t_{TTPmk}^{Thr}}\right) \tag{3.304}$$

t_{TTPmk}^{Thr} was taken as the MTTF of each equipment $\left(t_k^{\mathcal{F}}\right)$.

(5) Maintenance policy based total periodic maintenance expense per intervention

The total periodic maintenance expense per intervention refers to the expenses incurred per period during plant operation. It can by extension, be referred to as the actual cost of equipment intervention. The total periodic maintenance expense per intervention was also estimated for CM/PM (C_{xCPm}^{MTot}) and TA maintenance (C_{xTa}^{MTot}) respectively. C_{xCPm}^{MTot} and C_{xTa}^{MTot} were taken as the summed-up values of each equipment periodic maintenance expense per intervention for the respective maintenance policy (C_{xCPmk}^{MTot} and C_{xTa}^{MTot}). For each piece of equipment, C_{xCPmk}^{MTot} and C_{xTa}^{MTot} were obtained as their respective expected maintenance cost per intervention divided by their repair times provided that the required workforce and materials are available for the maintenance action (Equations 3.305 and 3.306).

$$C_{xCPm}^{MTot} = \sum_{k=1}^{k} C_{xCPmk}^{MTot} = \sum_{k=1}^{k} \frac{C_{CPmk}^{PerInt}}{t_{CPmk}^{IDur}} \quad \{E_k^{WMatAv} \neq 0; E_{Mtcek}^{Mode} > 1\} \quad (3.305)$$

$$C_{xTa}^{MTot} = \sum_{k=1}^{k} C_{xTak}^{MTot} = \sum_{k=1}^{k} \frac{C_{Tak}^{PerInt}}{t_{Tak}^{IDur}} \quad \{E_k^{WMatAv} \neq 0; E_{Mtcek}^{Mode} = 1\} \quad (3.306)$$

(6) Maintenance man-hours required for equipment

The CM/PM man-hour $\left(t_{CPmk}^{WRqrd}\right)$ and TA maintenance man-hour $\left(t_{Tak}^{Wrqrd}\right)$ for each equipment k were determined by first estimating the unit man-hours for maintenance work per MTPA $\left(\bar{\mathcal{M}}_{zk}^{Unit}; [z: CPm, Ta]\right)$. This was achieved by reducing $\bar{\mathcal{M}}_k$ (obtained from secondary data for a plant production capacity of 4.5 MTPA) to an equivalent value corresponding to 1 MTPA (Equation 3.307). Subsequently, the maintenance man-hour required for any of the maintenance modes was estimated as the product of the plant capacity, $\bar{\mathcal{M}}_{zk}^{Unit}$, and a factor that considers issues that relate to workforce logistics $\left(f_{Log}^{MW}\right)$ [Equation 3.308].

$$\bar{\mathcal{M}}_{zk}^{Unit} = int\left(\frac{\bar{\mathcal{M}}_{zk}}{4.5}\right) \quad (3.307)$$

$$t_{zk}^{WRqrd} = f_{Log}^{MW} \bar{\mathcal{M}}_{zk}^{Unit} P_{DC,t^*} \quad (3.308)$$

$$z: CPm, Ta$$

(7) Number of maintenance workers request

The number of maintenance workers requested for E_k $\left(W_{Mtcek}^{Rqst}\right)$ (measured in people per MTPA) was estimated as the number of man-hours $\left(t_{zk}^{WRqrd}\right)$ of N_k^{Unit} equipment units designated for the maintenance task divided by the expected repair time $(\bar{\mathcal{R}}_k)$ for the task provided a demand for such a workforce has been made (Equation 3.309).

$$W_{Mtcek}^{Rqst} = \begin{cases} int\left(\frac{t_{Tak}^{WRqrd} N_k^{Unit}}{4.5\bar{\mathcal{R}}_k}\right) & \{E_{Dunk}^{WRqst} = 1\} \\ int\left(\frac{t_{Cpmk}^{WRqrd} N_k^{Unit}}{4.5\bar{\mathcal{R}}_k}\right) & \{E_{Dunk}^{WRqst} > 1\} \end{cases} \quad (3.309)$$

(8) Periodic material usage rate

The periodic material usage rate $\left(\ddot{M}_{Mat}^{Usage}\right)$ refers to the amount of maintenance spares and related materials consumed during maintenance activities. It was estimated as the sum of CM/PM and TA maintenance material usage for all equipment under intervention at t^* (Equation 3.310).

$$\ddot{M}_{Mat}^{Usage} = \sum_{k=1}^{K} \ddot{M}_{Matk}^{Usage} = \sum_{k=1}^{K} (C_{xCPm}^{MTot} + C_{xTa}^{MTot}) \tag{3.310}$$

The derivation and results for the equipment reliability and maintenance manpower parameters are summarised and presented in Appendix D.

3.12.3 Model Evaluation approaches and activities

The SD-LNG-LCC model performance in terms of its result was evaluated after all input parameters had been defined and the computer program implemented.

3.12.3.1 Model evaluation approaches

Three general evaluation approaches were adopted in the study namely; the mean absolute percentage error, student's t-test of means comparison, and the LNG operation and economic performance evaluation measures.

(1) Mean absolute percentage error measures

This involved the comparison of time-influenced model output(s) $\left[R_{t^*}^{Mod}\right]$ with some corresponding reference result(s) $\left[R_{t^*}^{Ref}\right]$ ($\forall t^*$) based on the mean absolute percentage error (MAPE). The form of MAPE deployed was either based on non-cumulative or cumulative $R_{t^*}^{Mod}$ and $R_{t^*}^{Ref}$ values respectively (Equation 3.311). The cumulative form of the MAPE (Equation 3.312) was also adopted so as to be able to evaluate scenarios of strong uncertainties and shocks. Inferences were drawn from the evaluation on the basis of the Lewis (1982) MAPE inference proposition.

$$e_{Ncum}^{MAPE} = 100 \frac{\left|R_{t^*}^{Mod} - R_{t^*}^{Ref}\right|}{R_{t^*}^{Mod}} \tag{3.311}$$

$$e_{Cum}^{MAPE} = 100\frac{\left|\sum R_{t^*}^{Mod} - \sum R_{t^*}^{Ref}\right|}{\sum R_{t^*}^{Mod}} \quad (3.312)$$

(2) Student's t-test of means comparison

This mode of evaluation involved subjecting $R_{t^*}^{Mod}$ and $R_{t^*}^{Ref}$ to t-tests to ascertain if the model and reference results are similar or different from each other. To do this, the procedure, the null hypothesis (H_0) and alternative hypothesis (H_1) questions to be decided on were as follows,

H_0: There is no significant difference between $R_{t^*}^{Mod}$ and $R_{t^*}^{Ref}$

H_1: There is a significant difference exist between $R_{t^*}^{Mod}$ and $R_{t^*}^{Ref}$

The tests were conducted at a 95% confidence interval $(p_{Crt} = 0.05)$ to obtain the p-value of the t-test statistic (p_{stat}) using the data analysis package available in Microsoft EXCEL 2013. In each of the test cases, H_0 was not rejected if $p_{stat} > p_{Crt}$ that is, it was concluded that no significant difference exists between $R_{t^*}^{Mod}$ and $R_{t^*}^{Ref}$. Otherwise, it was concluded that $R_{t^*}^{Mod}$ and $R_{t^*}^{Ref}$ were different indicating poor SD-LNG-LCC performance.

(3) LNG operation and economic performance evaluation measures

Based on the level of confidence inferred from evaluating the model by the use of evaluation approaches 1 and 2, the evaluation of the model results in terms of the economic, operational and financial performance measures frequently deployed in the LNG industry. ten operational and eight economic performance measures were utilised. Table 3.7 displays the different industry performance measures used.

For subsequent discussion, the model evaluation approaches (MEA) will be referred to as MEA1, MEA2 and MEA3 respectively and should be noted.

3.12.3.2 Model evaluation activities

In evaluating the model, some activities were undertaken. The objectives of the evaluation activities were to,

(1) Ascertain the technical correctness of the model

Table 3.7: LNG industry performance measures used in the evaluation of the SD-LNG-LCC model

Performance measures		
SN	**Operation**	**Economic/Financial**
1	Base plant/expansion cost	Net present value (NPV)
2	Unit production cost	Payback period
3	Maintenance cost	Return on Investment (ROI)
4	Capital expenditure (CAPEX)	Cash flow
5	Operational expenses (OPEX)	Breakeven point
		i. Breakeven quantity ii. Breakeven time
6	Life cycle cost	Revenue
7	Liquefied LNG Volume	Profitability index
8	Equipment availability	Internal rate of return (IRR)
9	Plant Availability	
10	Operating capacity	

(2) Compare the results produced by the model with those reported by the LNGFWA within the time frame of the case study.

(3) Investigate the effect of some of the inputs on the LCC and economic performance of the organisation under study.

The evaluation activities are discussed in subsections 3.12.3.3- 3.12.3.5.

3.12.3.3 Technical correctness of model

The SD-based LCC model was evaluated to ascertain the correctness of the model development procedure employed. This was achieved by investigating the material flow balance and LCC-Total investment balance of the system.

Regarding the material balance, it is theoretically, expected that at any operation period in the plant, the total feed gas input in the system $\left(V_{Feedt^*}^{TotNG}\right)$ should be equal to the sum of the total LNG output, finished product in inventory and materials that are work-in-process $\left(V_{Syst^*}^{TotNG}\right)$ [Equations 3.313 – 3.315].

$$V_{Feedt^*}^{TotNG} = V_{Syst^*}^{TotNG} \qquad \{\forall t^*\} \tag{3.313}$$

Where,

$$V_{Feedt^*}^{TotNG} = \int_{t=0}^{t^*} \dot{V}_{Feedt^*}^{NG}\, dt \qquad \{t^* = 1,2,3, \ldots, T^*\} \tag{3.314}$$

$$V_{Syst^*}^{TotNG} = \left(V_{Storet^*}^{NG} + V_{inproct^*}^{NG} + V_{FuGt^*} + V_{prodt^*}^{TotLNG} + V_{inproct^*}^{NGw}\right) \tag{3.315}$$

However, real systems are non-exact, and as such the condition described in Equation 3.313 may not be attainable. Rather, a more realistic approach was to investigate how close in value $\dot{V}_{Sys}^{TotNG}$ was to $\dot{V}_{Feed}^{TotNG}$. To this end, a comparison of $\dot{V}_{Feed}^{TotNG}$ and $\dot{V}_{Sys}^{TotNG}$ was done based on MEA1 and MEA2 models. The various LNG/Feed gas materials that make up the input and outputs of the process were identified (Table 3.8).

Similarly, the total LCC and Total investment values at $t^* = P_L$ were also compared using MEA1.

3.12.3.4 Comparison of model results with case study data

A comparative evaluation of some of the SD-LNG-LCC model results with the real-time operations data of the LNGFWA was undertaken. This comparison was done by comparing the model's annual outcomes of revenue $\left(\dot{G}_{Rev}^{Mod}\right)$, and volume of LNG sold $\left(\dot{V}_{LNGMOD}^{shipped}\right)$ respectively with those of the organisation under study $\left(\dot{G}_{Rev}^{FWA}\right.$ and $\left.\dot{V}_{LNGFWA}^{shipped}\right)$. These evaluations were done using the MEA1 and MEA2.

3.12.3.5 System life cycle cost and economic performance analysis

The effect of some of the model's input parameters on the LCC and economic performance of the LNGFWA was evaluated using MEA 3. The evaluation was carried out in two sets of activities. In the first set, evaluation was done based on the input values of the LCC cost driver quantities (Table 3.3) and their effect on the system's LCC. The input values used were the firm's specific primary and secondary input data.

In the second set of activities, scenario analysis was used to study the impact of the changes in the input parameters on the system's performance. This involved the creation of different system conditions by varying the values of chosen input(s) by a fraction of the current input, then implementing the model based on the modified input(s). Table 3.8 shows the input parameters that were deployed for the scenario analysis and their corresponding inputs for each scenario expressed as a fraction of their current values.

Table 3.8: Input parameters and corresponding fraction of their current values deployed in the scenario evaluation of the SD-LNG-LCC model

Input parameters								
SN	**Name**	**Symbol**	**Varied scenario**					
			1	**2**	**3**	**4**	**5**	**6**
1	Greenfield projects versus Brownfield projects (MTPA)	G/B	Greenfield equivalent of the firm's current design capacity at its operating capacity conditions					
2	Train Capacity (MTPA)		3	5	10	20	30	50
3	LNG Stock Price (Gas)*	C_{LNG}^{Gas}	50	75	100	125	150	175
4	Plant productivity*	K^{PrC}	10	30	50	90	100	110
5	Maintenance Effectiveness (%)	f_{mtce}^{eff}	10	30	50	70	90	100
6	Maintenance strategy (Equipment quality parameter)	P_k	0.50	0.60	0.70	0.80	0.90	0.99
7	LNG charter (vessel) speed	$\bar{V}$	9	11	13	15	19	21

* The varied scenario values are a percentage of the current values used in the current state of the LNG firm that operates in West Africa (LNGFWA).

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 LNG System Sectors and Associated Components (Quantities)

Three main sectors: production, financial management and maintenance were identified. A total of five hundred and sixteen LNG distinct quantities were identified: one hundred and forty-seven from the production sector (See Table B1 in appendix B); one hundred and sixty from the financial management sector (Table B2 in appendix B) and two hundred and nine from the maintenance wing (Table B3 in Appendix B). From these one hundred and twenty-eight input parameters were recognised as presented in Table 4.1. Fifty-six components presented in Table 4.1 were found to be direct drivers LNG cost.

These direct drivers of LNG cost include the design capacities of the Greenfield and Brownfield plants, plant site and location factors. Other cost drivers identified (Table 4.1) include the CAPEX and OPEX funding factors which influence the availability of funds for LNG operations and sustenance. Also, the costs per unit plant design capacity as they relate to construction, equipment purchases and maintenancewere also identified. Other economic factors such as inflation factors, interest on capital policy, the unit price of the feedgas and LNG sale price were also identified. Some of the identified factors such as site and location complexities, material and maintenance cost show similarity in characteristics when compared to cost driving factors identified in literature (DiNapoli and Yost, 1998; Songhurst, 2018). However, other identified cost drivers such as funding factors, budgeting factors and leakage factors are unique to this study and their identification were made possible by the systems dynamics approach deployed in the analysis of liquefied natural gas operations.

4.2 Causal Relationships between LNG Components (Quantities)

Aside from the LNG system inputs, the other system components have direct or indirect interacting interrelationships that enable the entire LNG business to yield expected results.

Table 4.1: Direct drivers LNG cost

S/N	Description
1	Brownfield Plant Design Capacity (BPDC)
2	Bulk Material Cost Per Unit BPDC
3	Bulk Material Cost Per Unit GPDC
4	CAPEX Funding Factor
5	Construction Cost Per Unit BPDC
6	Construction Cost Per Unit GPDC
7	Depreciation Consideration factor
8	Depreciation Expense Rate Factor
9	Discount Rate
10	Engineering and Project Management Cost per Unit BPDC
11	Engineering and Project Management Cost per Unit GPDC
12	Equipment Cost Per Unit BPDC
13	Equipment Cost Per Unit GPDC
14	Equipment Maintenance Funding Factor (FF)
15	Equipment Maintenance Fund Leakage Factor (FLF)
16	LNG Cost Per Shipping Trip
17	Equipment Maintenance Fund Leakage Factor (FLF)
18	Feed Gas Funding Factor
19	Feed Gas Fund Leakage Factor
20	Feed Gas Fund Implementation Level
21	Fuel Gas Funding Factor
22	Fuel Gas Fund Implementation Level
23	Fuel Gas Fund Leakage Factor
24	Fund Access Factor
25	Greenfield Plant Design Capacity (GPDC)
26	Inflation Factor
27	Interest on Capital Policy
28	IOC Fraction
29	IHC Fraction
30	Labour Funding Factor
31	Labour Fund Implementation Level
32	Labour Fund Leakage Factor
33	LNG Price
34	LNG Stock Price (Gas)
35	Maintenance Labour Wage Rate

Table 4.1 (Continued): Direct drivers LNG cost

S/N	Description
36	Maintenance Operators Budget Factor
37	MMC Factor
38	MMBTU-LNG Converter
39	OPEX Fund Availability Factor (FAF)
40	OH Funding Factor
41	OH Fund Implementation Level
42	OH Fund Leakage Factor
43	Owners Cost Per Unit BPDC
44	Owners Cost Per Unit GPDC
45	Periodic OPEX Budget
46	Periodic OPEX Budgeting Factor
47	Periodic OH Cost
48	Periodic Shipment Delivered
49	Plant Useful Life
50	Previous activity-based OPEX Rate
51	Site Complexity Factor
52	Site Location Factor
53	Shipping Funding Factor
54	Shipping Fund Implementation Level (FIL)
55	Shipping Fund Leakage Factor (FLF)
56	Operating Time -Year Conversion Factor

These deduced relationships were presented in form of causal loop diagrams (Figures 3.3 and 3.4) and flow diagrams (Figures 3.5 and 3.6). It may be noted that these diagrams indicate, for each quantity, the quantities it directly impacts upon (using arrows) in order to achieve system desired changes. The flow diagram further indicates whether such a change in the affected quantity is positive or negative.

4.3 LNG System Simulation Model

The sub-sector governing equations form the basis for developing the simulation model of the LNG Life Cycle Cost system. The computer source code of the simulation model is presented in Appendix A. The authentication of the model using secondary data from a real-life firm tagged LNGFWA found in the West African region follows.

4.4 Brief Description of the LNGFWA LNG Producing Firm

The LNGFWA is a joint venture that has been in existence for more than three decades. However, actual LNG production began in 1999. Over this period, four brownfield expansion projects have been completed on the single existing base plant. Currently, the plant operates six LNG trains having a total design capacity of 22.20 MTPA. Its two major products are LNG and natural gas liquids (NGL).

The organisation essentially operates a continuous process made up of two work shifts of 12 hours per shift. The organisation receives its feed gas stock from suppliers via pipeline for onward liquefaction. The purity (methane content) of the feed gas is about 91.60%. The organisation has over 1000 members of staff who are responsible for production, maintenance, supply and administration.

For its product supply operations, the firm currently owns twelve LNG carriers and eleven more in its charter with each having a carriage volume ranging between 130,000 and 170,000 cubic metre. Within the period of its existence, the organisation has supplied its products to various countries across different continents (Europe, America and Asia) across the world.

4.5 Input Data

The results of the input data obtained from the LNGFWA cut across the finance, production operation and maintenance operation sectors include the plant useful life, CAPEX elements, periodic OPEX budget, equipment maintenance cost, equipment maintenance intervention intervals, and number of operation personnel. Others include the process bottleneck factor, the unplanned failure distribution parameters for failure occurrences and the shipping cost estimation inputs. Table 4.2 shows the non-time dependent inputs while the time-dependent input (TDI) quantities such as the bottleneck factor, CAPEX, feed gas cost and LNG sale price are shown in Table 4.3 and Figures 4.1- 4.4.

Specifically, Table 4.3 shows the breakdown of the CAPEX in terms of its constituent elements. Figures 4.1 and 4.2 compare the LNGFWA CAPEX element fractions with those from a stated literature source on the basis of Greenfield and Brownfield projects.

The TDI for the operating capacity factor, plant bottleneck factor and feed gas supply of the LNGFWA activities are displayed in Figure 4.3. Figure 4.4 are input information on the LNG stock and sale prices within the studied operation period. Generally, for the SD-LNG-LCC model to be successfully applied to a functioning or prospective LNG system, a total of 128 input parameters that cut across the three major sectors of LNG operations must be defined. The TDI inputs are discussed next.

4.5.1 Capital expenditure elements

The derived finance sector-based input is the CAPEX elements, the LNG stock price, and the LNG price. Regarding the CAPEX elements, the 2014 base evaluation period cost values per unit MTPA for construction, equipment, bulk materials, ownership, engineering and project management for Greenfield projects ($C_c^G, C_E^G, C_M^G, C_c^{OwnG}, C_c^{EPmG}$) were 243.12, 163.64, 122.92, 61.46, and 50.54 million dollars (Table 4.3). However, for expansion projects, the costs for the same elements ($C_c^B, C_E^B, C_M^B, C_c^{OwnB}, C_c^{EPmB}$) were 36.69, 204.88, 122.93, 61.47, and 50.51 million dollars respectively (Table 4.3).

Table 4.2: SD-LNG-LCC input quantities and corresponding values for the LNGFWA case application

SN	Description	Symbol	Dimension	Value
1	Average charter Speed	$\bar{V}$	$Knot/Day$	15.84
2	Average Expected Ship/Vessel Displacement	$\bar{D}$	$Tonne$	139897
3	Brownfield Unit Train Capacity	V_{Tr}^{B}	$MTPA$	TDI*
4	Bulk Material Cost Per Unit BPDC	C_{BM}^{UCap}	$\$/MTPA$	73.187×10^6
5	Bulk Material Cost Per Unit GPDC	C_{GM}^{UCap}	$\$/MTPA$	109.091×10^6
6	CAPEX Funding Factor	Ψ_{EX}^{C}	$Dmnl$	1
7	Construction Cost Per Unit BPDC	C_{BC}^{UCap}	$\$/MTPA$	117.099×10^6
8	Construction Cost Per Unit GPDC	C_{GC}^{UCap}	$\$/MTPA$	174.545×10^6
9	Depreciation Consideration factor	K_D	$Dmnl$	1
10	Depreciation Expense Rate Factor	f_{DP}^{Exp}	$1/Month$	672
11	Discount Rate	r^{Disc}	$\%/Year$	12
12	Engineering and Project Management Cost per Unit BPDC	C_{BEpm}^{UCap}	$\$/MTPA$	43.636×10^6
13	Engineering and Project Management Cost per Unit GPDC	C_{GEpm}^{UCap}	$\$/MTPA$	43.636×10^6
14	Equipment Cost Per Unit BPDC	C_{BE}^{UCap}	$\$/MTPA$	190.285×10^6
15	Equipment Cost Per Unit GPDC	C_{GE}^{UCap}	$\$/MTPA$	163.636×10^6
16	Equipment Maintenance Funding Factor (FF)	K_{Mtce}^{FF}	$Dmnl$	1
17	Equipment Maintenance Fund Implementation Level (FIL)	K_{Mtce}^{IL}	$Dmnl$	1
18	Equipment Maintenance Fund Leakage Factor (FLF)	K_{Mtce}^{FLF}	$Dmnl$	1
19	Feed Gas Funding Factor	K_{FG}^{FF}	$Dmnl$	1
20	Feed Gas Fund Leakage Factor	K_{FG}^{FLF}	$Dmnl$	1
21	Feed Gas Fund Implementation Level	K_{FG}^{IL}	$Dmnl$	1
22	Fuel Gas Funding Factor	K_{FuG}^{FF}	$Dmnl$	1
23	Fuel Gas Fund Implementation Level	K_{FuG}^{IL}	$Dmnl$	1
24	Fuel Gas Fund Leakage Factor	K_{FuG}^{FLF}	$Dmnl$	1
25	Fund Access Factor	f_{Fund}^{Access}	$Dmnl$	10

Table 4.2 (Continued): SD-LNG-LCC input quantities and corresponding values for the LNGFWA case application

SN	Description	Symbol	Dimension	Value
26	Greenfield Unit Train Capacity	G	$MTPA$	TDI*
27	Heel allocation	$\dot{V}_{Loss}^{Heel}$	%	5
28	Inflation Factor	f^{Infl}	$Dmnl$	TDI*
29	Interest on Capital Policy	K_{CF}^{Intrst}	$Dmnl$	0
30	IOC Fraction	f_{Ord}^{I}	$Dmnl$	15
31	IHC Fraction	f_{Hold}^{I}	$\%/Month$	25
32	Labour Funding Factor	K_{Lab}^{FF}	$Dmnl$	1
34	Labour Fund Implementation Level	K_{Lab}^{IL}	$Dmnl$	1
35	Labour Fund Leakage Factor	K_{Lab}^{FLF}	$Dmnl$	1
36	LNG Price	C^{LNG}	$\$/mmBTU$	TDI*
37	LNG Stock Price (Gas)	C_{LNG}^{Gas}	$\$/cm^3Gas$	TDI*
38	Maintenance Operators Budget Factor	K_{BF}^{MP}	$Dmnl$	1
39	MMBTU-LNG Converter	f_{LNG}^{mmBTU}	$\frac{mmBTU}{m_{LNG}^3}$	24.36
40	MMC Factor	f_{Mtce}^{MMC}	%	5
41	OPEX Budgeting Factor	Ψ_{EX}^{O}	$Dmnl$	1.05
42	OPEX Fund Availability Factor (FAF)	Ω_{EX}^{O}	$1/Month$	672
43	OPEX Fund Implementation Level (FIL)	F_{IL}^{O}	$Dmnl$	1
44	OH Funding Factor	K_{OH}^{FF}	$Dmnl$	1
45	OH Fund Implementation Level	K_{OH}^{IL}	$Dmnl$	1
46	OH Fund Leakage Factor	K_{OH}^{FLF}	$Dmnl$	1
47	Periodic OPEX Budget	$\hat{B}_{EX}^{O}$	\$/Month	2.659×10^6
48	Owners Cost Per Unit BPDC	C_{BOwn}^{UCap}	$\$/MTPA$	54.546×10^6
49	Owners Cost Per Unit GPDC	C_{GOwn}^{UCap}	$\$/MTPA$	54.546×10^6
50	Periodic OH Cost	C_{OH}^{O}	$\$/Month$	TDI*
51	Plant Useful Life	P_L	$Month$	252
52	Site Complexity Factor	f_{Site}^{Cmplx}	$Dmnl$	1
53	Site Location Factor	f_{Site}^{Loc}	$Dmnl$	1
54	Operating Time -Year Conversion Factor	f_{Yr}^{POP}	$Month/Year$	12
55	Active PP Assignment Termination Factor	f_{PTerm}^{WAct}	$1/Month$	672

Table 4.2 (Continued): SD-LNG-LCC input quantities and corresponding values for the LNGFWA case application

SN	Description	Symbol	Dimension	Value
56	Active PP Firing Frequency	f_{PFire}^{WAct}	$1/Month$	672
57	Transit BOG Fraction	f_{BOG}^{Trnst}	$\%/day$	0.15
58	Gas-LNG Converter	f_{LNG}^{Gas}	m_{gas}^3/m_{LNG}^3	585
59	Desired Workforce Lower Tolerance	f_{LProd}^{Trnce}	%	12
60	Desired Workforce Upper Tolerance	f_{UProd}^{Trnce}	%	15
61	Expected Workload Execution Time	t_{Exptd}^{WLExe}	$Month$	TDI*
62	Facility Location Factor	f^{Loc}	$Dmnl$	1
63	Feed Gas Supply Interval	t_{Feed}^{NG}	$Month$	1.488×10^{-3}
64	Fuel Usage Factor	f_{Fu}^{Usage}	%	10
65	Greenfield Unit Train Capacity	V_{Tr}^{G}	$MTPA$ $/Train$	TDI*
66	Inactive Production Personnel Firing Frequency	f_{prod}^{WFire}	$1/Month$	672
67	Jetty BOG Factor	f_{BOG}^{Jetty}	$Dmnl$	0
68	LNG Delivery Interval	t_{Ready}^{ship}	$Month$	1
69	LNG Storage Capacity	V_{SCap}^{LNG}	m^3	6×10^5
70	Logistics-Based Delay in Delivery	D_{Prep}^{ship}	$Month$	0.714
71	Maximum (Max.) Shipload Capacity	V_{Max}^{ship}	m^3	7×10^5
72	Natural Gas (NG) Conversion Factor	K^{NGC}	%	91.6
73	NG Plant Capacity Factor	K^{PlC}	$Dmnl$	5
74	NG Stock Joint Use Factor	K_{stock}^{NG}	$Dmnl$	5
75	Non-Mtce. Related Feed Gas Delays	D_{Feed}^{NG*}	$Dmnl$	1
76	Number of Brownfield Trains	N_{Tr}^{B}	$Dmnl$	1
77	Number of Greenfield Trains	N_{Tr}^{G}	$Dmnl$	1
79	OPEX Fund Implementation Level (OFIL)	F_{IL}^{O}	$Dmnl$	1
80	Order Receipt Policy on TA Mtce.	f_{Policy}^{OrdRct}	$Dmnl$	0
81	Order Release (OR) Delay	D_{OR}^{delay}	$Month$	1.488×10^{-3}
82	OR Fraction	K_{OR}^{delay}	$Dmnl$	1
83	Plant Unit Operation Window	t_{pw}^{*}	$Month$	1.488×10^{-3}
84	Plant productivity	K^{PrC}	$Dmnl$	0.975
85	PO Interval	t^{po}	$Month$	1.488×10^{-3}
86	Production Operator Productivity	θ_{Prod}	$Dmnl$	1

Table 4.2 (Continued): SD-LNG-LCC input quantities and corresponding values for the LNGFWA case application

SN	Description	Symbol	Dimension	Value
87	Production Recruitment Delay Period	$t_{Prod}^{DRcrit*}$	$Month$	7.440×10^{-3}
88	Production Resource Availability Factor	f_{Prod}^{ResAv}	$Dmnl$	1
89	Expected Unit Workforce Production Rate	W_{prod}^{URate}	Man/m_{gas}^{3}	70
90	Recruited Production Personnel Release Frequency	f_{Prod}^{RcrRel}	$1/Month$	672
91	CM Logistics Factor for E_k	f_{Ek}^{LogCM}	$Dmnl$	0.5
92	CM Efficiency for E_k	f_{Ek}^{TecCM}	$Dmnl$	1
93	CM/PM Intervention Duration for E_k	t_{CmPmk}^{IDur}	$Month$	TDI*
94	CM/PM Total Costs Per Intervention for E_k	C_{CPmk}^{TotInt}	$	TDI*
95	CM/PM Maintenance Man-hour Required for E_k	t_{CmPmk}^{WRqrd}	$ManMonth$	TDI*
96	CM Recruitment. Decision	f_{RecCm}^{Dec}	$Dmnl$	1
97	Decision for PM Recruitment	f_{RecPm}^{Dec}	$Dmnl$	1
98	Decision for TA Recruitment	f_{RecTaM}^{Dec}	$Dmnl$	1
99	Expected Lead Time	t_{Exptd}^{lead}	$Month$	1
100	Expected no. of planned shutdowns	N_{Plan}^{sdwn}	$Dmnl$	4
101	Frequency at which CM/PM Periodic Maintenance Workforce requirement is Met (RPMWM) for E_k	f_{CmPmk}^{Met}	$1/Month$	672
102	Frequency at which TA Periodic Maintenance Workforce requirement is Met (RPMWM) for E_k	f_{Tak}^{Met}	$1/Month$	672
103	Inventory Usage Efficiency Factor	f_{Usage}^{InvEff}	$Dmnl$	1
104	Maintenance Assignment Completion Delay Period for E_k	t_{MAss}^{Done*}	$Month$	1.488×10^{-3}
105	Maintenance Effectiveness	f_{mtce}^{eff}	$Dmnl$	0.95
106	Maintenance Personnel Outflow Factor	f_{mtce}^{Fire}	$1/Month$	1.488×10^{-3}
107	Maintenance Recruitment Delay Period	$t_{Mtce}^{DRcrit*}$	$Month$	7.440×10^{-3}

Table 4.2 (Continued): SD-LNG-LCC input quantities and corresponding values for the LNGFWA case application

SN	Description	Symbol	Dimension	Value
108	Maintenance Resource Availability Factor	f_{mtce}^{ReAv}	$Dmnl$	1
109	Maximum Loading Fraction	$f_{Ship}^{MaxLoad}$	$Dmnl$	0.98
110	PM Logistics Factor for E_k	f_{Ek}^{LogPM}	$Dmnl$	1
111	PM Efficiency Factor for E_k	f_{Ek}^{TecPM}	$Dmnl$	1
112	PM request Factor	f_{PMk}^{Req}	$Dmnl$	0.20
113	PM Threshold Period for E_k	t_k^{PMThr*}	$Month$	TDI*
114	TA Costs per Intervention for E_k	C_{Tak}^{PerInt}	$	TDI*
117	TA Logistics Factor for E_k	f_{Ek}^{LogTA}	$Dmnl$	0.9
118	TA Efficiency for E_k	f_{Ek}^{TecTA}	$Dmnl$	1
119	TA Maintenance Man-hour Required for E_k	t_{Tak}^{Wrqrd}	$Month$	TDI*
120	TA Maintenance Cost Fraction	f_{Ta}^{mtce}	$Dmnl$	0.40
121	TA Maintenance Duration for E_k	t_{Tak}^{IntDur}	$Month$	EBI**
122	TA Maintenance Time	t_{mtce}^{TA}	$Month$	50
123	TA Threshold Period for E_k	t_k^{TaThr*}	$Month$	50
123	Weibull Shape parameter for E_k	β_{Ek}	$Dmnl$	EBI**
125	Weibull Scale parameter for E_k	η_{Ek}	$Month$	EBI**
126	Annual workforce wage rate for permanent staff	W_{zPemnt}^{Wage}	$\$/Year$	120000
127	Annual workforce wage rate for contract staff	W_{zCtrct}^{Wage}	$\$/Year$	40000
128	Average workforce wage rate (at base year)	W_z^{Wage}	$\$/Year$	57040

TDI: Time-Dependent Input; EBI: Equipment-based input;

Table 4.3: CAPEX elements and corresponding cost per MTPA

CAPEX Elements (CE)	Plant Design Capacity (PDC)		Equipment Cost		Construction Cost		Bulk Material Cost		Engineering and Proj. Mgt. Cost		Owners Cost		Total CE Cost	
	GPDC	BPDC	GPDC	BPDC	GPDC	BPDC	GPDC	BPDC	GPDC	BPDC	GPDC	BPDC	Greenfield	Brownfield
	Cost Value $\times 10^6$ \$/MTPA													
	1	1	204.87	204.88	243.12	36.69	122.92	122.93	50.54	50.51	61.46	61.46	--	--
Total Equipment Cost	Yes	Yes	Yes	Yes	--	--	--	--	--	--	--	--	204.87	204.88
Total Construction Cost	Yes	Yes	--	--	Yes	Yes	--	--	--	--	--	--	243.12	36.69
Total Bulk Materials Cost	Yes	Yes	--	--	--	--	Yes	Yes	--	--	--	--	122.92	122.93
Engineering and Proj. Mgt. Cost	Yes	--	--	--	--	--	--	--	Yes	Yes	--	--	50.54	50.51
Owners Total Cost	Yes	--	--	--	--	--	--	--	--	--	Yes	Yes	61.46	61.46
Total CAPEX per project type	--	--	--	--	--	--	--	--	--	--	--	--	682.91	476.47
Total CAPEX	1159.38													

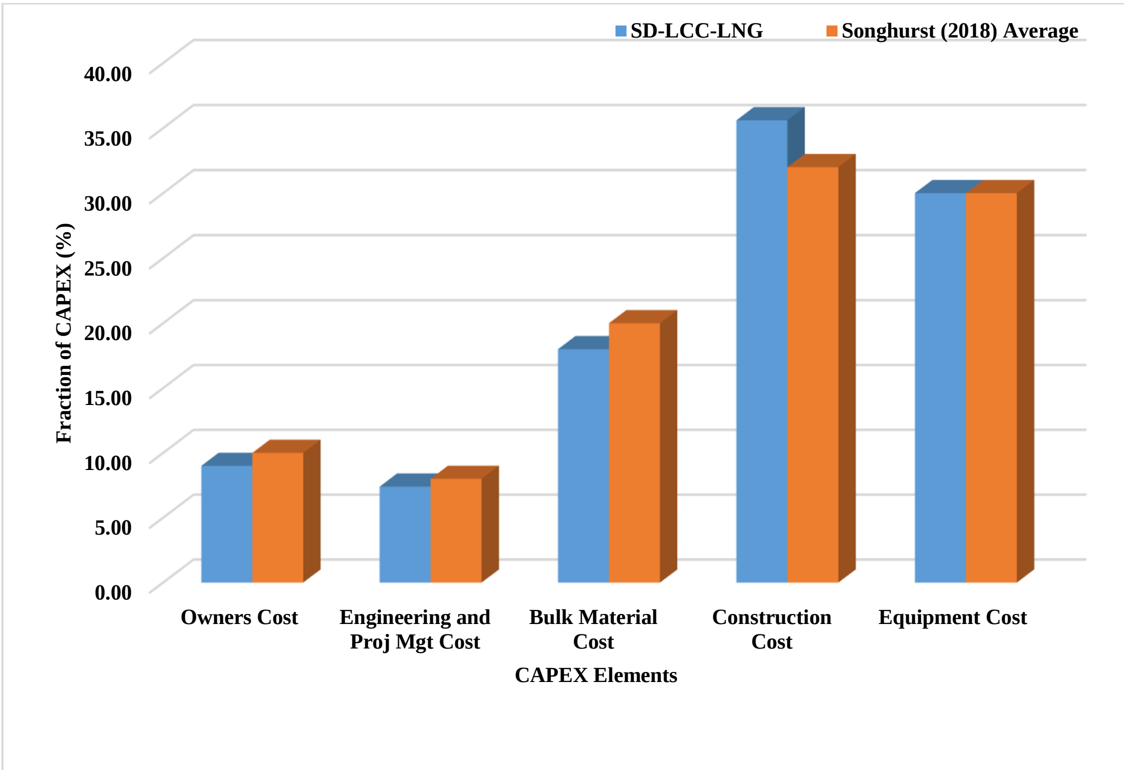

Figure 4.1: Comparison of model's Greenfield project CAPEX element fractions with those provided by Songhurst (2018)

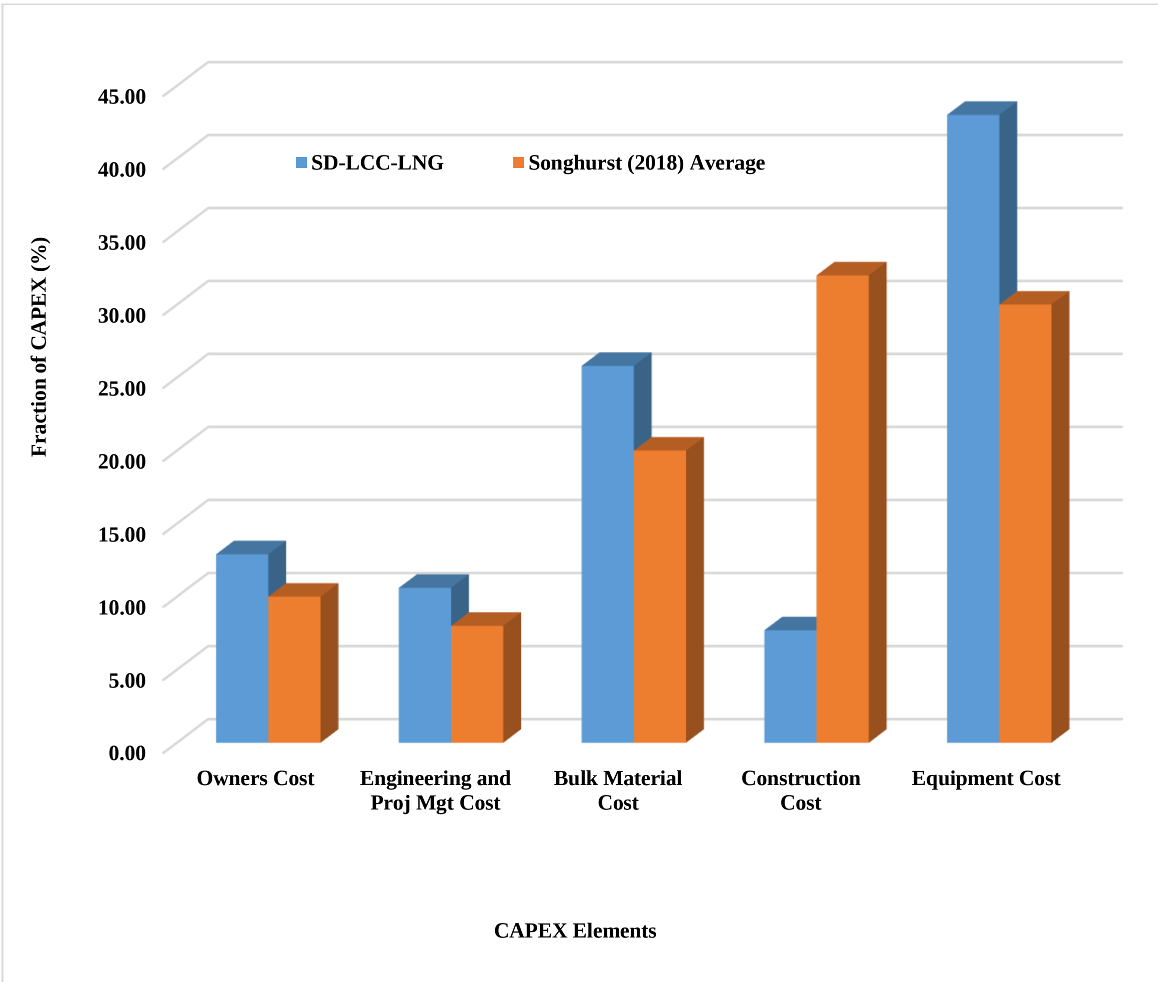

Figure 4.2: Comparison of model's Brownfield project CAPEX elements fractions with Songhurst (2018) Greenfield CAPEX elements data

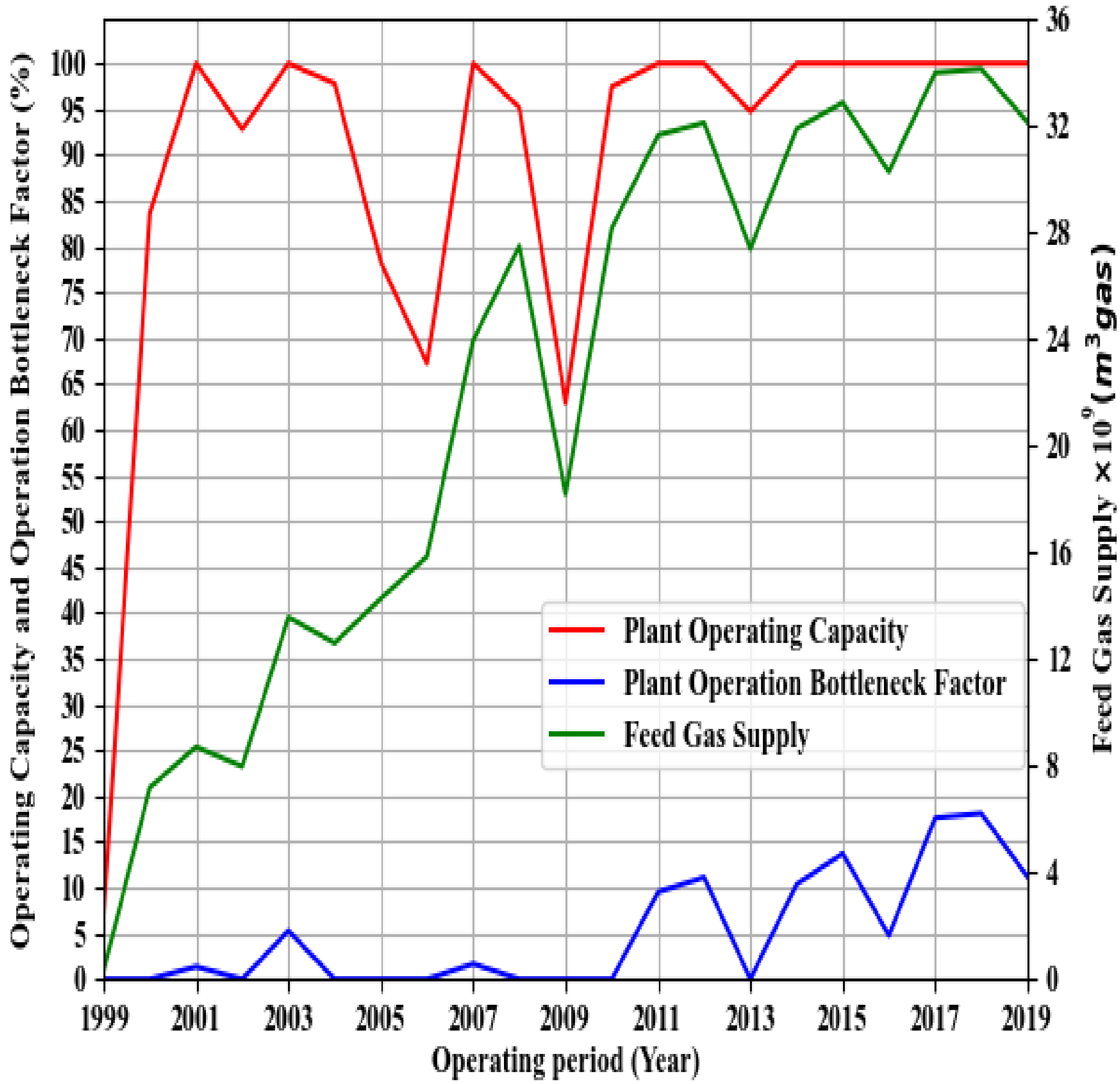

Figure 4.3: Operating Capacity factor, plant bottleneck factor and feed gas supply for the LNGFWA activities from 1999 to 2019

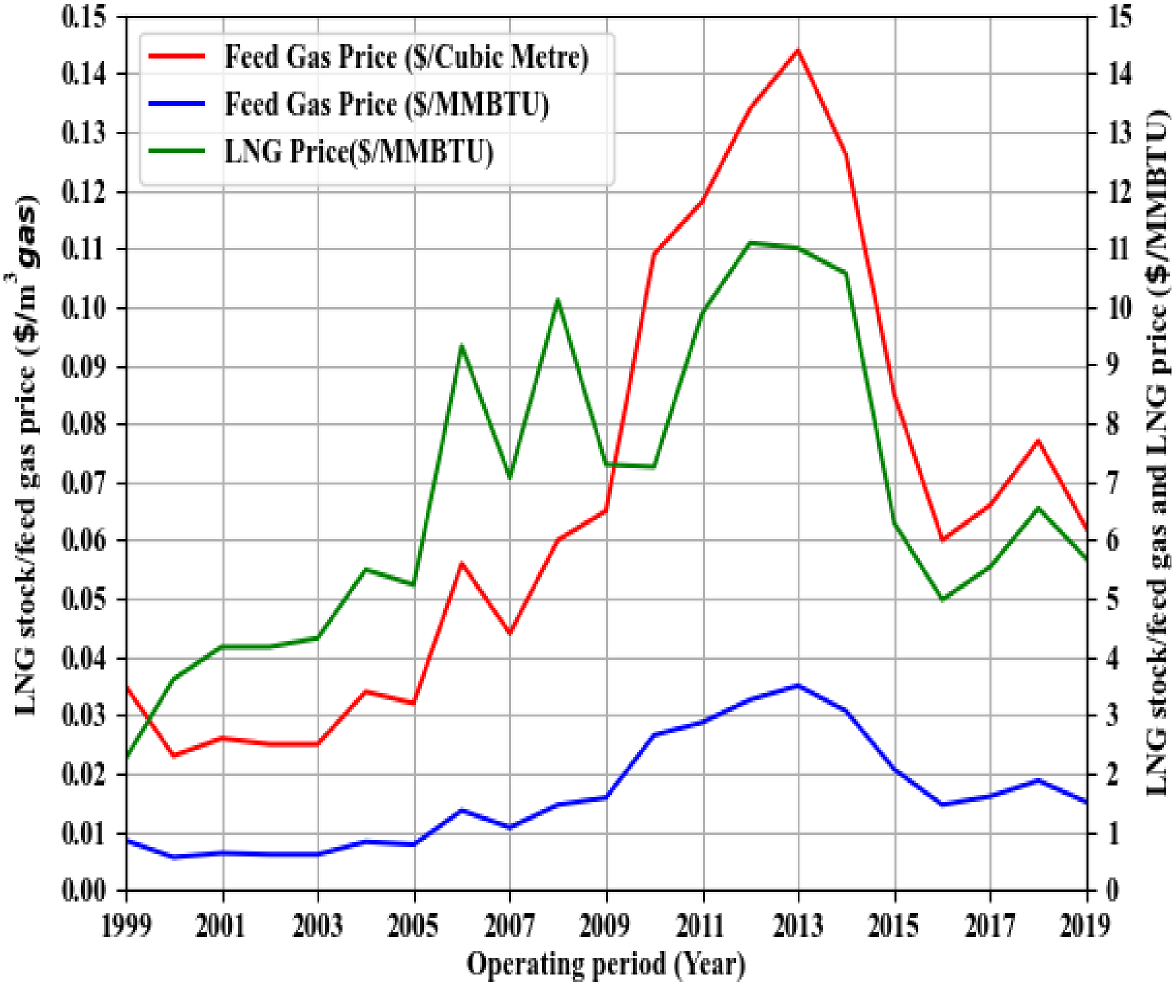

Figure 4.4: Annual LNG stock and sale prices within the studied operation period

As has also been corroborated in literature (Gomez, 2013; Raj *et al.*, 2016b), C_c^G and C_E^B were seen to be the most expensive of the base and expansion plant cost contributors respectively and in both base and expansion CAPEX types and together, constitute more than 50% of the entire CAPEX. This indicates that the cost of construction and equipment are the most significant CAPEX drivers in LNG projects. Although the cost of construction seemed the highest for base plant projects, it was observed to be lower by more than 80% in Brownfield projects. This was expected because of the reduced requirement for major constructing activities for liquefaction plants and terminals involving Brownfield projects.

However, equipment and bulk material costs respectively were observed to be essentially the same (205 and 123 million dollars per MTPA) for both base and expansion projects. This is understood to be so because equipment and bulk material costs are production capacity sensitive (DiNapoli and Yost, 1998) and as such, the cost of their constituents (such as compressors, gas turbines, heat exchangers, piping instrumentation and electrical installations) are dependent on the intended plant capacity. It was also observed that C_E^B and C_M^B together constituted about 48% and 69% of base and expansion projects respectively implying that although equipment and bulk materials are significant cost drivers in Greenfield projects, they are even more significant in influencing Brownfield project costs.

In similar manner, the owner's and the cost the engineering and project management cost per MPTA for both Greenfield and Brownfield projects were also retained as approximately the same value as they were assumed in this study to be plant design capacity sensitive also. However, this may not always be the case.

Generally, the results of the base plant CAPEX element fractions, align well with the industry average as reported by (Songhurst, 2018) and shown in Figures 4.1 and 4.2. With respect to the total base plant CAPEX per MTPA of $C_c^G, C_E^G, C_M^G, C_c^{OwnG}$ and C_c^{EPmG}, the LNGFWA fractions were, 25.6, 30.0, 18.0, 9.0 and 7.4% compared to the industry average of 32, 30, 20, 10, and 8.0%. However, no previous information on Brownfield CAPEX elements fractions seems exists in the literature for comparison with values of 7.7, 43.0, 25.8, 12.9, 10.6 (Figure 4.2) estimated in the study.

Furthermore, at the minimum complexities and plant location factors, the unit CAPEX for LNG Greenfield projects and Brownfield project cost about 682.91 and $476.47 per TPA respectively. Given that the range and average unit CAPEX for several LNG projects embarked on between 2014 and 2018 is 550-$2106 and $1072 respectively (Songhurst, 2018) . It does appear from these results, that the firm's unit Greenfield CAPEX is low relative to the industry indexes. However, if consideration is given to the fact that the project was embarked on about two decades earlier, the project value when adjusted for inflation effects in that time would be around 546 $/TPA. This unit Greenfield CAPEX is actually high when compared to the industry average of 520 $/TPA (DiNapoli and Yost, 1998) in that period. This clearly shows that the cost of setting up LNG projects have actually escalated in the last two decades.

Furthermore, Brownfield project costs were observed to be 69.77% of Greenfield projects. The means that the firms that execute more expansion projects over base projects are more likely to incur less CAPEX and in effect less LCC. It is worth noting that this values were derived based on a best case scenario where the plants may be conveniently located and the processes are non-complex.

4.5.2 Plant operating capacity, feed gas supply and bottleneck factor

Based on the derivations from the firm's secondary data, it was observed that the plant's operating capacity at startup (1999) was very low at 7.13% (305.99 MScf [10.82 BScf]). However, production quickly picked up from around year 2000. Between 2000 and 2019, the plant's operating capacity ranged between 63 and 100%. As can be observed from Figure 4.3, that plant operations generally experienced some troughs and peaks at the initial study period (1999 -2009) with an average of 80.45%. However, production picked up from 2010 with maximum feed supplies being attained more frequently. The average plant operating capacity within this period (2010 – 2019) was observed to be 99.22%.

The bottleneck factor $\left(K_{OBNt^*}^{P}\right)$ which reflects the extra fraction of feedstock purchased to accommodate fuel consumption and process related wastages was observed to exist with feedstock that exceeded the plant's full capacity requirement. Thus in periods where the operating capacities were 100%, the corresponding bottleneck factors ranged between

1.4% in 2001 to 18.1% in 2018 with an average of 10.46%. This average value indicates that in order for the plant to compensate for bottlenecks in its operations, a feed gas compensation of about 10 -11% may usually be required. This can be clearly observed in the amount of feed gas supplied to the plant at different operation periods including the period between 2014 and 2019 where the feed gas supplied exceeded the amount of 28.83BScm (22.2 MTPA of LNG) needed to meet the plant's output design capacity.

4.5.3 Feed gas price and LNG price

The annual price of feed stock/gas (C_{LNG}^{Gas}) purchased by the organisation seemed to gradually increase between 1999 and 2007 with values ranging between 0.025-$0.0443\$/m^3 gas$ $(0.61 - 1.36\,\$/MMBTu)$ [Figure 4.4]. However, a sharp incline was observed between 2008 and 2014 where C_{LNG}^{Gas} rose from $0.060\$/m^3 gas$ $(1.46\,\$/MMBTu)$ to as high as 0.144$ $(3.50\,\$/MMBTu)$. Thereafter, the gas prices began to drop although in general they remained relatively high and within an approximate average price of $0.070\$/m^3 gas$ $(1.70\,\$/MMBTu)$. Generally, the average value of C_{LNG}^{Gas} was $0.067\,\$/m^3 gas$ $(1.63\,\$/MMBTu)$.

It was observed from the data that the prices of the LNGFWA feed gas were quite reasonable as they fell within the expected range of $0 - 5\$/m^3 gas$ (Nagi *et al.*, 2016; Raj *et al.*, 2016b; Chandra, 2020). A similar trend was also observed in regards to the LNG price (C^{LNG}) [Figure 4.4]. For the time ranges of 1999-2007; 2008-2014 and 2015-2019, the LNGFWA made supplies to its product buyers at the price ranges of $2.25 - 7.07; 7.25 - 11.09$ and $4.98 - 6.54\$/MMBTu$ respectively. The average LNG price within the entire study period was determined as $6.76\$/MMBTu$.

The similarity in trend between C_{LNG}^{Gas} and C^{LNG} was understood to be the consequence of the LNGFWA, feed stock payments to its suppliers based on the units of sold energy (MMBTU) units. This observation agrees with those made by Steuer (2019).

4.5.4 Equipment maintenance and intervention

The inputs of the maintenance of the liquefaction equipment considered in the study, their failure characterisation parameters, maintenance/intervention parameters as well as their corresponding costs are presented and discussed. Table 4.4 provides information on the failure properties of the different NG liquefaction and transport equipment. The input parameters for the maintenance equipment intervention of the LNGFWA system are shown in Table 4.5. The estimated cost of carrying out maintenance interventions for the LNG equipment is provided in Table 4.6.

4.5.4.1 Equipment failure characterisation

It was observed that the different equipment types and classes possessed different failure rates (Table 4.4). The highest failure rate of approximately four failures per month occurred with gas separators $(490.53 \times 10^{-6}/hr)$, while the lowest failure rate occurred with the valves $(5.47 \times 10^{-6}/hr)$. The impact of the failure rate parameter can be observed in the corresponding Weibull scale parameter values of the equipment during their useful lives.

As designed into the SD-LNG-LCC, the frequency of equipment failure is most impacted by the scale parameter of the Weibull distribution since the shape parameter was kept constant in the study. This implied that generally, the lower the shape parameter distribution of an equipment, the higher the frequency of failure, and eventually the higher the impact on the cost of maintaining the equipment.

4.5.4.2 Equipment intervention parameters

The results for CM/PM (Table 4.5) reveal that the mean time to a preventive maintenance action as determined by the equipment failure characteristics ranged between 0.40 months (two weeks) gas separating equipment to 35.74 months (3 years) for valves. Generally, it is expected that the system could experience production delays at least once a year due to one form of required PM action or another as the system was observed to have a mean PM interval of 10.32 months.

Regarding the expected CM/PM intervention duration (t_{CmPmk}^{IDur}), the heat treatment equipment (gas treatment heaters and heat exchangers) required the longest intervention duration range of (40-52.9 hours). These were followed by the gas turbines, compressors and pumps (18.90-21.30), while the rest of the equipment in each required less than 10 hours for CM/PM action completion.

Table 4.4: Results of LNG equipment failure characterisation

Equipment ($\boldsymbol{E_k}$)	Class ($\boldsymbol{j}$)	Specification	Failure Rate ($\bar{\lambda}_{kj}$) [$\times 10^{-5} hr^{-1}$]	Weibull Scale Parameter ($\times 10^3 hr$) at Shape parameter=1.2		
				(Early Life)	(Useful Life)	Wear out Life
CT_j	1	3.5 MW	37.718	2.651	3.182	2.121
	2	11/21.5/43 MW	65.019	1.538	1.846	1.230
GTD_j	1	50 MW	200.000	0.500	0.599	0.400
$PCHE_j$	1	PFHE (8000-12000 m^2)	13.966	7.160	8.592	5.728
$MCHE_j$	1	SWHE (8000 - 10000 m^2)	12.961	7.715	9.259	6.172
GST_j	1	>=300 m^3	490.532	0.204	0.245	0.163
	2	<300 m^3	30.504	3.278	3.934	2.623
$VLVS_j$	1	All types	5.467	18.292	21.950	14.633
$OTHR_j$	1	Sensors, Fire/ Gas detectors, Pumps	14.000	7.143	8.571	5.714
$GSTH_j$	1	MW	21.255	4.705	5.646	3.764
$PPNG_j$	1	m	28.087	3.560	4.272	2.848
$TRPN_j$	1	m^3	13.00	7.691	10.097	6.153

Key:

CT_j: Compressors/Expanders; GTD_j: Gas turbine drivers; $PCHE_j$: Natural gas pre-cooling heat exchangers; $MCHE_j$: Main cryogenic heat exchangers; GST_j: Gas separators; $VLVS_j$: Valves; $GSTH_j$: Gas treatment heaters; $PPNG_j$: Piping; $TRPN_j$: Transportation/Shipping

Table 4.5: Results of the SD-LNG-LCC equipment maintenance intervention input parameters

Equipment (E_k)	Class (j)	CM/PM: Mean time to Mtce. Threshold (t^{Thr}_{TTPmk}) [$month$]	CM/PM: Intervention duration (t^{IDur}_{CmPmk}) [hr]	CM/PM: Workload W^{Wload}_{Cpmk} [$Manhr/MTPA$]	TA Maintenance: Mean time to Mtce. Threshold (t^{Thr}_{TTTak}) [$month$]	TA Maintenance: Number of Failure Modes ($N^{\mathcal{F}Mode}_k$)	TA Maintenance: Intervention duration (t^{IDur}_{Tak}) [hr]	TA Maintenance: Workload W^{Wload}_{Tak} [$Manhr/MTPA$]
CT_j	1	5.18	9.00	7	50.40	23	207.00	143
	2	3.00	18.90	42	50.40	38	718.20	1536
GTD_j	1	0.98	19.40	36	50.40	25	485.00	840
$PCHE_j$	1	13.99	48.00	88	50.40	7	336.00	600
$MCHE_j$	1	12.96	40.00	32	50.40	7	280.00	218
GST_j	1	0.40	4.50	2	50.40	17	76.50	24
	2	6.40	8.20	3	50.40	15	123.00	33
$VLVS_j$	1	35.74	6.00	2	50.40	25	150.00	42
$OTHR_j$	1	13.95	21.30	7	50.40	10	213.00	68
$GSTH_j$	1	9.19	52.90	66	50.40	6	317.40	393
$PPNG_j$	1	6.96	6.00	3	50.40	10	60.00	22
$TRPN_j$	1	15.03	3.70	*27	50.40	194	720.00	*72000

***The values for shipping are in $Manhr/Vessel$**

Table 4.6: The expected cost of maintenance interventions for LNG Equipment for base evaluation period (2014)

Equipment (E_k)	Class (j)	Expected MIC by Equipment Total [$\$/Tonne$]			Expected MIC by number of interventions				Expected MIC by Annual values			
		CP/PM	TA	Total	Expected total MI		Cost per MIC per unit plant capacity		MI frequency [$Year^{-1}$]		MIC per Unit Capacity [$\$/TPA$]	
		C_{CPm}^{Int}	C_{Ta}^{Int}		$N_{CPmkt^*}^{Int}$	$N_{Takt^*}^{Int}$	$C_{CPmkt^*}^{PerInt}$	$C_{Takt^*}^{PerInt}$	N_{CPmk1}^{Int}	N_{Tak1}^{Int}	C_{CPmk}^{Int}	C_{Tak1}^{Int}
CT_j	1	0.557	0.372	0.929	46	4	0.012	0.093	2.19	0.19	0.02	0.018
	2	21.104	14.069	35.174	80	4	0.264	3.517	3.81	0.19	1.00	0.670
GTD_j	1	20.051	13.367	33.418	246	4	0.082	3.342	11.71	0.19	0.95	0.637
$PCHE_j$	1	24.056	16.037	40.093	17	4	1.415	4.009	0.81	0.19	1.14	0.764
$MCHE_j$	1	11.991	7.994	19.986	16	4	0.749	1.999	0.76	0.19	0.57	0.381
GST_j	1	0.415	0.277	0.692	602	4	0.001	0.069	28.67	0.19	0.02	0.013
	2	0.129	0.086	0.214	37	4	0.003	0.021	1.76	0.19	0.00	0.004
$VLVS_j$	1	0.360	0.240	0.600	7	4	0.051	0.060	0.33	0.19	0.01	0.011
$OTHR_j$	1	6.721	4.481	11.202	17	4	0.395	1.120	0.81	0.19	0.32	0.213
$GSTH_j$	1	0.078	0.052	0.130	26	4	0.003	0.013	1.24	0.19	0.00	0.002
$PPNG_j$	1	11.762	7.841	19.603	35	4	0.336	1.960	1.67	0.19	0.56	0.373
$TRPN_j$	1	6.539	4.360	10.899	16	4	0.409	1.090	0.76	0.19	0.31	0.208
Total	--	103.765	69.175	172.938	--	--	3.721	17.294	--	--	4.94	3.294
Grand		172.938					21.014				8.235	

MIC: Maintenance Intervention Cost; MI: Maintenance Intervention

This trend was also followed in regard to the number of maintenance workforce requested per intervention for a unit plant design capacity of 1 MTPA.

For example, the treatment heaters and NG pre-cooling heat exchanger required 66 and 88 maintenance personnel respectively, while equipment such as the 3.5 MW rated compressors (CT_1), pumps and sensors $(OTHR_j)$, separators (GST_j), piping $(PPNG_j)$ and valves required 7, 7, 5, 3 and 2 maintenance personnel respectively. It was observed however, that although a single unit of ship and product transport vessel $(TRPN_j)$ required a small maintenance period of 3.7 hours, the corresponding number of maintenance personnel was relatively high (27 people). This behaviour was tied to the number of maintenance tasks required for the equipment as indicated by the number of failure modes (194) as well as their complexities.

Regarding TA maintenance intervention input, the value for the time to TA maintenance threshold for all equipment was the same (50.4 Months, [4.20 years]). This is expected because as expected, TA/shutdown maintenance is usually kick-started at the same time and in such situations, all production operations are usually suspended. This is understandable because during TA maintenance action, it is expected that all known equipment failure modes $(N_k^{\mathcal{F}Mode})$ will be addressed to ensure the equipment are in the best of health at the restart of operations. Thus the higher the $N_k^{\mathcal{F}Mode}$, the higher the likelihood of a lengthier TA maintenance duration for E_k. The workload requirement per maintenance intervention was observed to be of a high range (27- 88 Manhr/MTPA for PM/CM and 143-72000 Manhr/MTPA for TA maintenance respectively) for compressors, gas turbines, heat treatment and product transportation equipment, while it was lower for the other equipment (Table 4.5).

4.5.4.3 Expected maintenance intervention cost per unit plant capacity

The estimated cost of carrying out maintenance interventions for the LNG equipment (Table 4.6) revealed that for all equipment considered, the total expected cost of undertaking all maintenance within the study period interventions ranged between 0.13 and 40.09 $/Tonne with the cooling heat exchangers, compressors and gas turbines expected to incur the highest total intervention cost. On the other hand, it is expected that the gas treatment heaters, gas separators and valves will incur the least intervention cost values.

A further breakdown of the expected cost revealed that a single maintenance intervention for a unit plant design capacity of 1 TPA of LNG ranges between 0.001 – 1.415 dollars and 0.021 – 4.009 dollars for CM/PM $\left(C_{CPmkt^*}^{PerInt}\right)$ and TA maintenance $\left(C_{Takt^*}^{PerInt}\right)$ respectively. This indicated that for a unit plant capacity of 1 MTPA, the total CM/PM cost per intervention was around the region of \$3.72 million while that for TA maintenance was \$17.29 million. For the three maintenance strategies considered, the three equipment with the least total cost per intervention are the gas separators (Classes 1 and 2) and the gas treatment heater, while the three highest costing equipment maintenance per intervention are the propane cooling heat exchangers, compressor (Class 2) and the gas turbine drivers.

Using the Total Maintenance intervention cost as a basis, it can be clearly observed from Table 4.6 that maintenance of critical equipment including compressors (CT_2), gas turbines (GTD), the pre cooling $(PCHE)$ and main cryogenic heat exchangers $(MCHE)$, piping $(PPNG)$ and shipping vessels $(TRPN)$ are expected to cost more. This is so because on the one hand, most of the equipment mentioned bear the highest relative cost of purchase and as such, their maintenance cost is also expected to be high since the method of their estimation is partly proportional to their purchase cost. On the other hand, as can be observed for $GTD, PCHE$ and $MCHE$ in Table 4.5, the expected intervention cost is also be impacted by the large number of failure modes observed for the equipment.

It can also be observed from Table 4.6, that equipment with lower expected CM/PM intervention costs seemed to correspond with higher expected number of interventions during the plant operating life $\left(N_{Takt^*}^{Int}\right)$. This again is related to the deployed maintenance intervention cost estimation method which essentially utilises $N_{Takt^*}^{Int}$ as a divisor for the total expected cost of all interventions completed on each equipment.

The expected annual PM (C_{Pmk1}^{Int}) and TA maintenance cost (C_{Tak1}^{Int}) per unit plant capacity (Table 4.6) provides another perspective into the expected cost of maintenance intervention. It shows that the expected annual maintenance cost range per TPA for PM and TA maintenance respectively is 0.004-1.146 and 0.003 – 0.764 dollars per TPA. The results further emphasises that $CT_2, GTD, PCHE, TRPN, PPNG$ and $MCHE$, are the most costly items to maintain in the LNG liquefaction project.

Overall, the expected annual maintenance cost for the LNG system was estimated 8.235$\$/TPA$. Given that the expected intervention costs are quantities that were determined via assumptions based on static scenarios, it is expected however, that due to uncertainty and stochasticity influences in the system due to factors such as inflation, lubrication cost changes etc., the actual maintenance cost which provides a more realistic perspective of the cost of system intervention, will likely differ. The actual maintenance cost is discussed as one of the model's output quantities in a subsequent section.

4.5.5 Shipping cost inputs and estimated parameters

The shipping cost inputs deployed within the study period are displayed in Figures 4.5- 4.9. Specifically, the transport vessels' destination regions and the corresponding fraction of the total product delivered in those regions is shown in Figure 4.5. Figure 4.6 describes the trend of the mean maximum shipload capacity and mean annual charter travel distance while the estimated port charges on shipment vessels are shown in Figure 4.7. Information on the daily vessel charter rate with their corresponding charter rate contributors is shown in Figure 4.8 respectively. The different fuel prices for the two types of shipping vessel fuel oils considered in the study is presented in Figure 4.9 while estimated fleet speed and fuel consumption requirement are presented in Table 4.7. A discussion of these inputs is carried out subsequently.

4.5.5.1 Periodic sales volume fraction shipped

Figure 4.5 shows that over the study period, the LNFGWA has supplied its product to various markets across the globe including countries in Europe, North America, South America, South Asia, Middle East and Africa. The European market has remained the largest market to which the organisation has supplied its product. Between 1999 and 2011, the market alone accounted for more or less 70% of the sold product. Thereafter however, the demand for the product waned. Nonetheless, the region remained the most significant market for the LNGFWA.

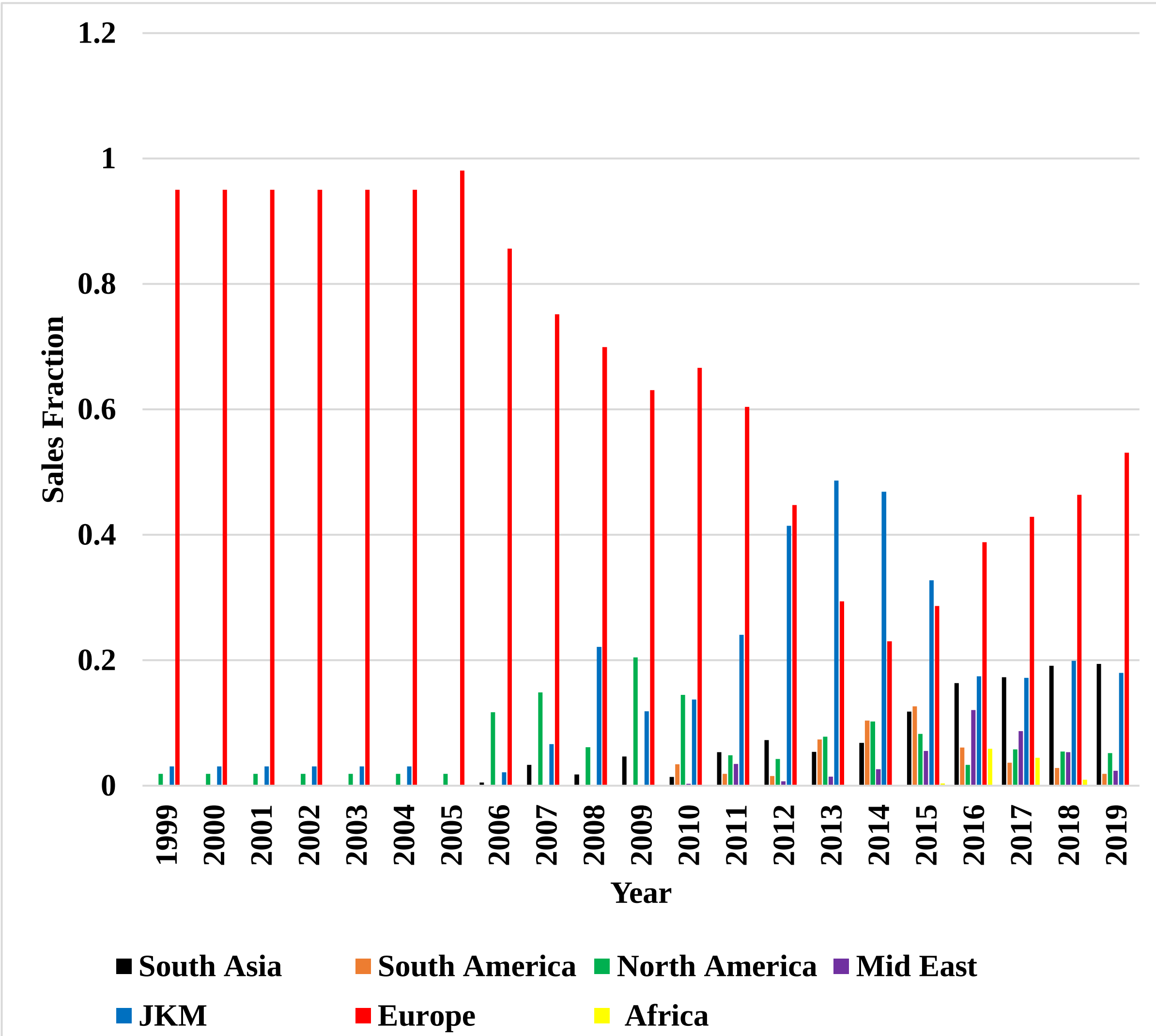

Figure 4.5: LNGFWA product buyer groups and the corresponding annual fraction of product sold to them

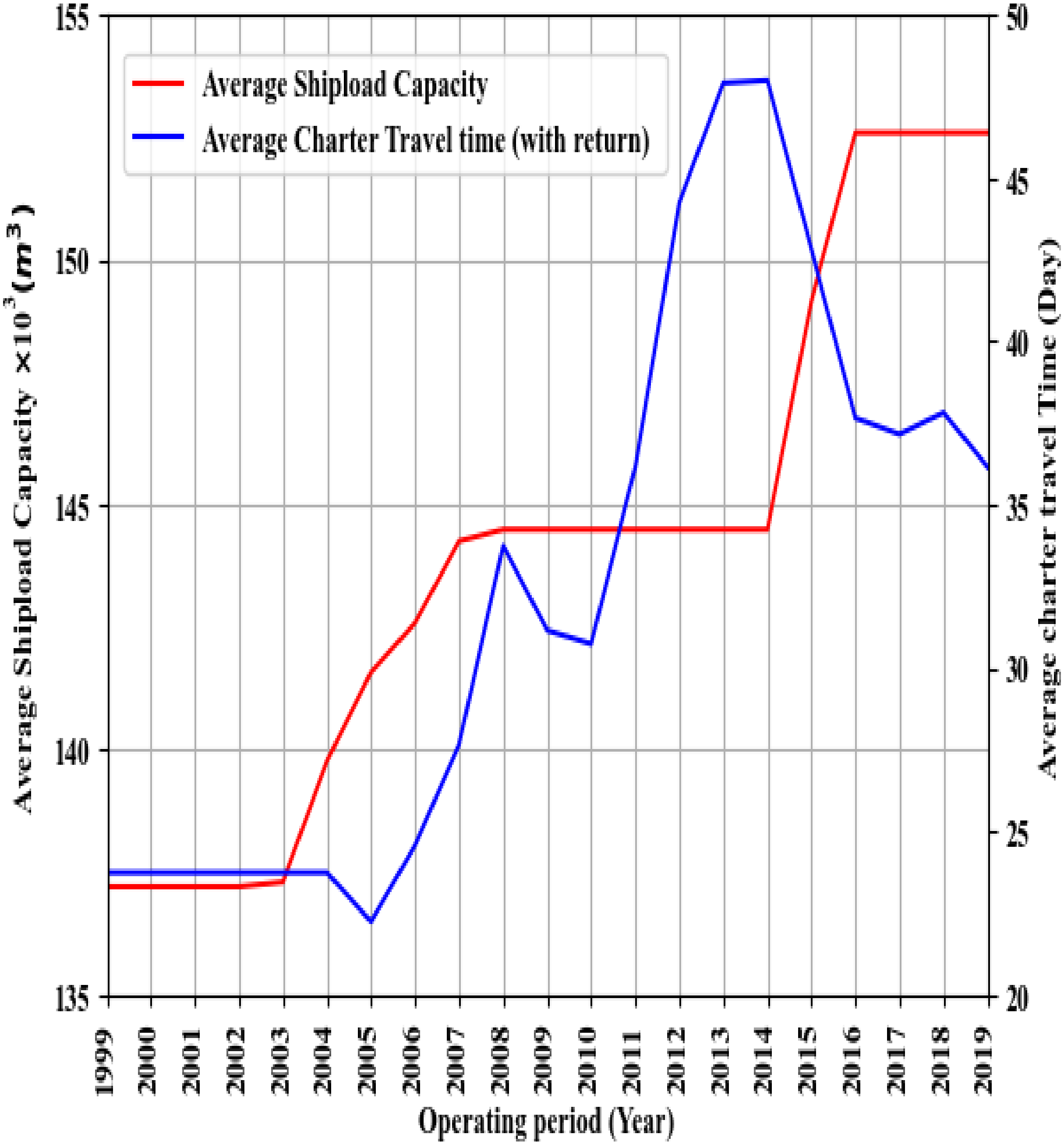

Figure 4.6: Trend of the LNGFWA average maximum shipload capacity and mean charter travel time within the studied operation period

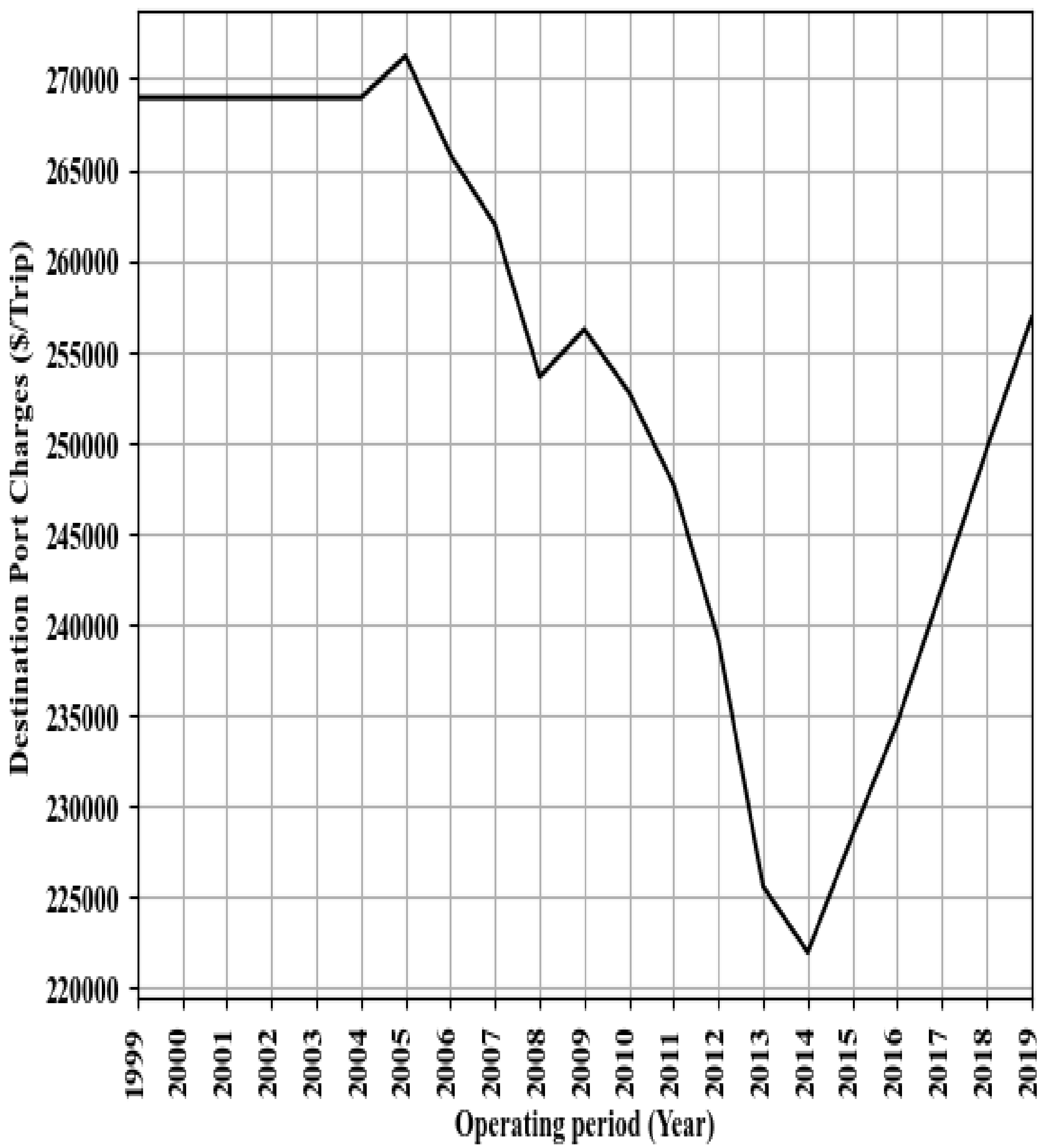

Figure 4.7: Estimate of the LNGFWA destination port charges per shipment trip at different operating periods

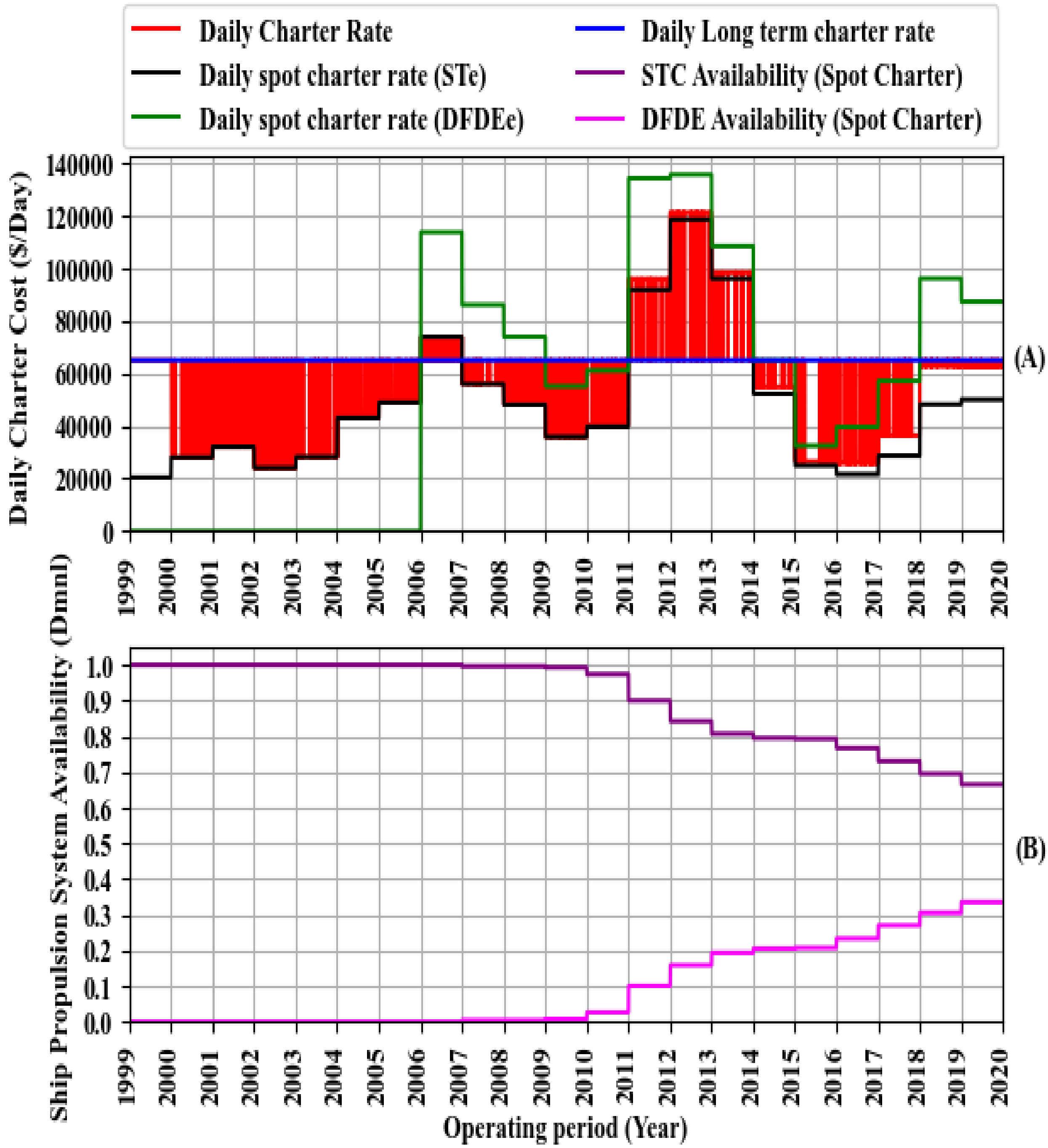

Figure 4.8: Propulsion system influenced daily vessel spot and long term charter rates and the LNGFWA estimated inputs

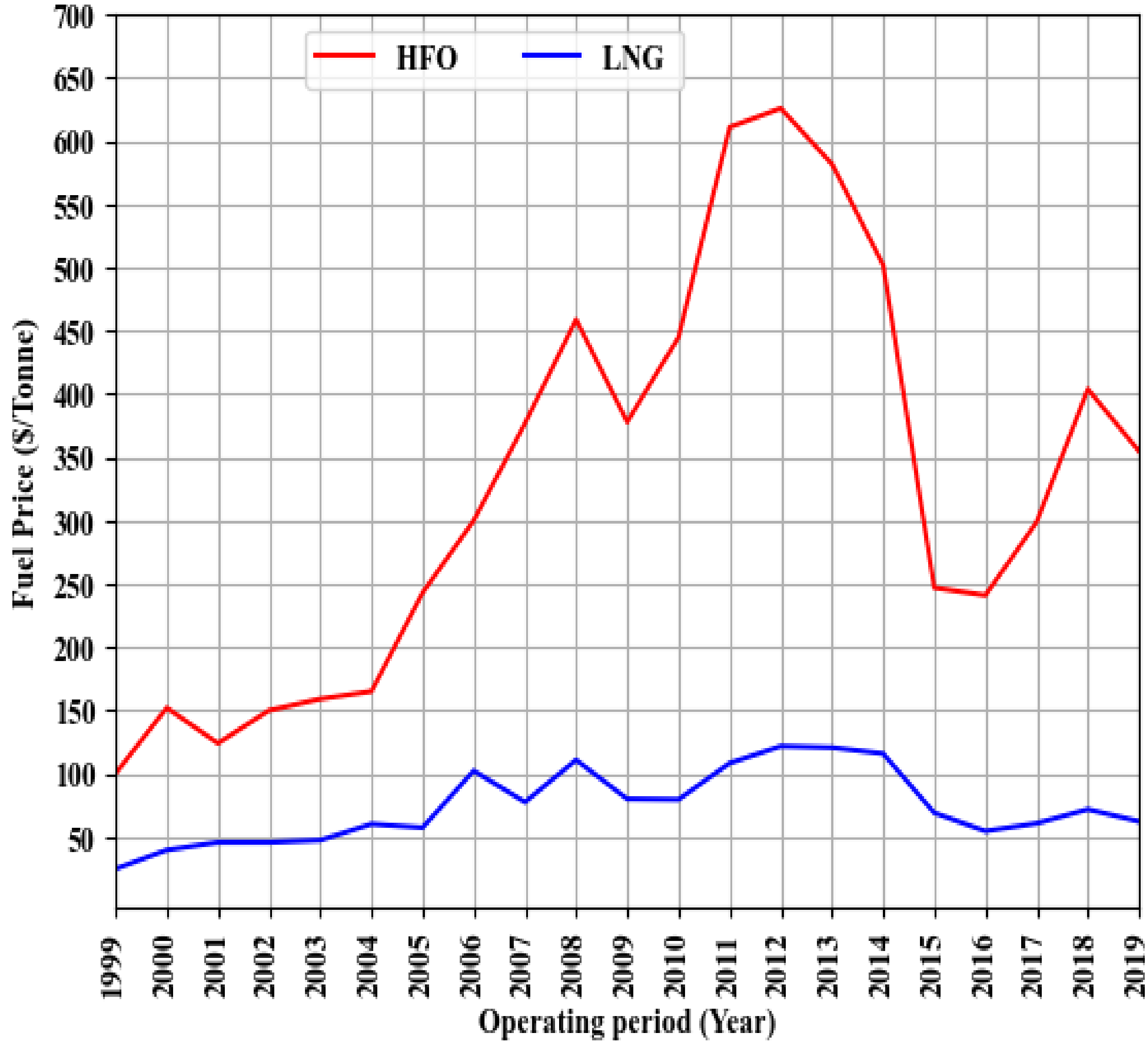

Figure 4.9: Annual Fuel Prices of LNG and HFO fuels for shipping vessels

Table 4.7: The LNGFWA Fuel consumption estimated parameters

SN	Parameter	Propulsion system	
		Dual-Fuel Diesel-Electric Engine (*DFDEe*)	**Steam Turbine Carrier Engine (STCe)**
1	Vessels' average speed (Knots)	15.84	15.84
2	Daily Heavy fuel oil (HFO) consumption estimate (*tonnes/day*)	67.23	97.27
3	Daily LNG Burn off gas (BOG) consumption estimate (*tonnes/day*)	49.87	72.22
4	Average Daily BOG fuel consumption estimate (*tonnes/day*)	94.15	94.15

Other significant markets are the Japan-Korean market (JKM) (2008-2019) and within the latter part of the study period, the South Asian market (2012-2019).

4.5.5.2 Charter LNG lifting volume

As a result of the effect of the different phases of the project expansion by the firm's shipping resources, the purchase, lease and use of different ship capacities at various periods within the operation window implied that the total volume of LNG shipped varied throughout the study period.

Figure 4.6 shows that between 1999 and 2003, the average maximum fleet loading capacity was around 135×10^3 m^3. However on the availability of larger vessels in the market coupled with the need to deliver larger product volume, the loading capacity rose to values between 140×10^3 and 145×10^3 m^3 between 2004 and the subsequent decade. Thereafter, the average maximum fleet loading capacity rose up to 152×10^3 m^3. These values clearly, indicate that the carriers in organisation's charter are generally large carriers (Steuer, 2019).

4.5.5.3 Loading-delivery distance and daily port charges

The distances between the loading and delivery ports (t_{Trvl}^{Ship}) for these markets certainly influence the LCC of the LNG project. The average speed of the charter vessel which directly impacts on the loading-delivery distance was estimated to be 15.84 kt for the LNGFWA (Table 4.7). This value is indicative of a super slow steaming shipping policy adopted by the firm with the likely purpose being to minimise fuel consumption while in service (transportgeography, 2017).

Based on this, the average annual charter travel time for laden and ballast journey can be observed (Figure 4.6) to be constant (23.75 days) between 1999 and 2004. It however decreases in 2005 to about 22 days as a result of the lack of supplies to the JKM only to increase again the following year on resumption of supply. The highest impact on t_{Trvl}^{Ship} was observed to occur between 2012 and 2015 and coincides with the period when the JKM sales fraction was comparatively more dominant (0.35-0.45). Thus depending on the vessel speed, the LCC of the project will be impacted by the proximity of the loading and unloading ports.

Regarding the port charges incurred during shipment, the impact of the firm's extent of supply to different buyer groups and their corresponding port charges caused the aggregated daily port charges estimate at different periods to lie in the range of 221, 000 and 272,000 dollars per trip (Figure 4.7).

4.5.5.4 Daily charter rate

Another important shipping cost input parameter is that of the vessel daily charter rate. Figure 4.8 shows that over the study period, the values between the start and end of the study window constantly fluctuated between the long term charter cost ($65000/day) and the spot charter costs. Given that traditionally, the industry shipping preferences has always been higher for long term charters over short term charters (Forto, 2016; Barrios, 2018), this observation implied that the fleet in the organisation's long term charter appears inadequate to cater for all the LNG shipment requirement when needed and as such short charter supplements were utilised.

Regarding the cost of spot charter, it can be observed that the rates for the $STCe$ and $DFDEe$ propulsion systems appeared volatile as they constantly fluctuated over the study period with the $STCe$ rate being generally lower than the $DFDEe$ rate by an average of about 32.92%. Thus, it can be observed from Figure 4.8A that except for the periods between 2011 and 2014, the spot charter supplement was mainly of the $STCe$ propulsion system even though the $STCe$ is a less fuel efficient system.

Apart from the perceived of higher cost of charter, the lesser preference by the LNGFWA for the $DFDEe$ system can be understood from its availability. It can also be observed from Figure 4.8B that the $DFDEe$ propulsion system was virtually inexistent for commercial use until 2017. By 2011 the ratio of $DFDEe$ to $STCe$ was about 1 to 9. However, notwithstanding its relatively higher freight rate, the $DFDEe$ has been increasingly gaining popularity in usage as it is superior to the $STCe$ in terms of fuel efficiency and environmental friendliness. In addition, Rogers (2018) has shown that the $DFDEe$ is financially more economical than the $STCe$. Thus it can observed from Figure 4.8B, that the trend over the time between its commercialisation and the end of the study window indicates an increasing production of $DFDEe$ vessels over the $STCe$ system.

4.5.5.5 Fuel rates for shipping vessels

The fuel price for shipping vessels is an important factor of influence on the LCC of an LNG production system. Figure 4.9 shows that over the past two decades that the prices of LNG has constantly remained below that of the heavy fuel oil (HFO). This brings into understanding why the use of LNG BOGs is prioritised as fuel over the HFO. However, due to the unsustainability in the use of BOGs for complete laden and ballast voyages, the use of HFO and other related fuel oil types become necessary. Development in recent years, has seen the development of propulsion systems designed specifically for the use of LNG as fuel (Akina, 2021; Keller, 2021; Buls, 2022).

Based on the 15.84 *knot* average speed and 139.90$ktonne$ expected displacement of the LNGFWA charter obtained (Table 4.7), it was determined that the $STCe$ and $DFDEe$ propulsion systems require 97.27 and 67.23 tonnes of HFO per day (72.22 and 49.87 *tonnes/day* of LNG) respectively. It is clearly obvious in terms of fuel consumption that the utilization of the $STCe$ adds more to the LCC of the LNG production project than the use of the $DFDEe$. Furthermore, the amount of daily LNG cargo BOG which generally varied with respect to the amount of cargo shipped was estimated at an average value of 94.15 *tonnes/day*. This shows that at 15.84 *knots*, the daily BOG is greater than the LNG BOG fuel requirements of both the STe and $DFDEe$ and as such the organisation over the study period may have made little or no need for the use of HFO supplement.

It is worth noting here that although the vessel speed obtained in the study is close to the industry average of 16.3 *knot* (Axelsen, 2018), it is only a general reflection of the entire charter. Other circumstances may cause the vessels to operate at other speeds including the vessels' specified minimum and maximum. This can create other fuel consumption scenarios.

4.6 Model Correctness

The results of the material flow balance investigation for ascertaining the technical correctness of the SD-LNG-LCC model are shown in Tables 4.8 and Table 4.9 respectively. Figure 4.10 shows the LCC-Total investment balance evaluation results.

Table 4.8: Result of Material balance MAPE evaluation for input, work-in-process and output materials

Operating Period (t^*)	****Output and work-in-process materials**					**Input material** $(V^{TotNG}_{Feedt^*})$	**Total Output and work-in-process materials** $(V^{TotNG}_{Syst^*})$	**Input-Output Error**	**Input-Output APE** (%)
	$V^{NG}_{Storet^*}$	V_{FuGt^*}	$V^{NG}_{inproct^*}$	$V^{LNG}_{prodt^*}$	V^{wge}_{inproc}				
	$\times 10^9 m^3 gas$								
1999	0.0002	0.0000	0.0000	0.2468	0.0295	0.2764	0.2764	0.0000	0.0000
2000	0.0035	0.0000	0.0009	5.4626	0.6520	6.1190	6.1190	0.0000	0.0000
2001	0.0043	0.0000	0.0011	12.5207	1.4944	14.0204	14.0204	0.0000	0.0000
2002	0.0039	0.0000	0.0010	19.0082	2.2686	21.2817	21.2818	-0.0001	0.0005
2003	0.0067	0.0000	0.0017	29.0267	3.4644	32.4995	32.4994	0.0001	0.0003
2004	0.0062	0.0000	0.0016	39.1594	4.6737	43.8410	43.8409	0.0001	0.0002
2005	0.0070	0.0000	0.0018	50.8145	6.0648	56.8881	56.8881	0.0000	0.0000
2006	0.0078	0.0000	0.0020	63.7708	7.6111	71.3916	71.3917	-0.0001	0.0001
2007	0.0117	0.0000	0.0030	81.2884	9.7018	91.0048	91.0049	-0.0001	0.0001
2008	0.0136	0.0000	0.0034	103.5404	12.3577	115.9144	115.9151	-0.0007	0.0006
2009	0.0090	0.0000	0.0023	118.4891	14.1417	132.6423	132.6421	0.0002	0.0002
2010	0.0140	0.0000	0.0035	141.1075	16.8413	157.9655	157.9662	-0.0007	0.0004
2011	0.0155	0.0000	0.0039	164.2118	19.5989	183.8309	183.8302	0.0007	0.0004
2012	0.0159	0.0000	0.0040	190.6785	22.7576	213.4560	213.4560	0.0000	0.0000
2013	0.0136	0.0000	0.0034	212.9126	25.4114	238.3404	238.3409	-0.0005	0.0002
2014	0.0158	0.0000	0.0039	238.6607	28.4843	267.1649	267.1647	0.0002	0.0001
2015	0.0163	0.0000	0.0041	265.2391	31.6566	296.9161	296.9161	0.0000	0.0000
2016	0.0150	0.0000	0.0037	287.5923	34.3244	321.9357	321.9354	0.0003	0.0001
2017	0.0168	0.0000	0.0042	314.4775	37.5331	352.0312	352.0317	-0.0005	0.0001
2018	0.0169	0.0000	0.0042	341.6075	40.7713	382.4002	382.3999	0.0003	0.0001
2019	0.0158	0.0000	0.0040	367.5140	43.8631	411.3970	411.3970	0.0000	0.0000
								MAPE	0.0002

Table 4.9: t-Test results for material flow balance evaluation

Student t-test properties	$V_{Feedt^*}^{TotNG}$	$V_{Syst^*}^{TotNG}$
Mean ($\times 10^9$)	162.444	162.4437
Variance ($\times 10^{22}$)	18043.106	18043.101
Standard Deviation ($\times 10^9$)	134.325	134.325
Observations	21	21
Pooled Variance ($\times 10^{22}$)	18043.1040	
Hypothesized Mean Difference	0.0000	
Degree of Freedom	40	
t Stat	0.0000	
P(F<=f) [Variance]	0.5000	
F Critical one-tail (Variance)	1.6839	
P(T<=t) two-tail	1.0000	
t Critical two-tail	2.0211	

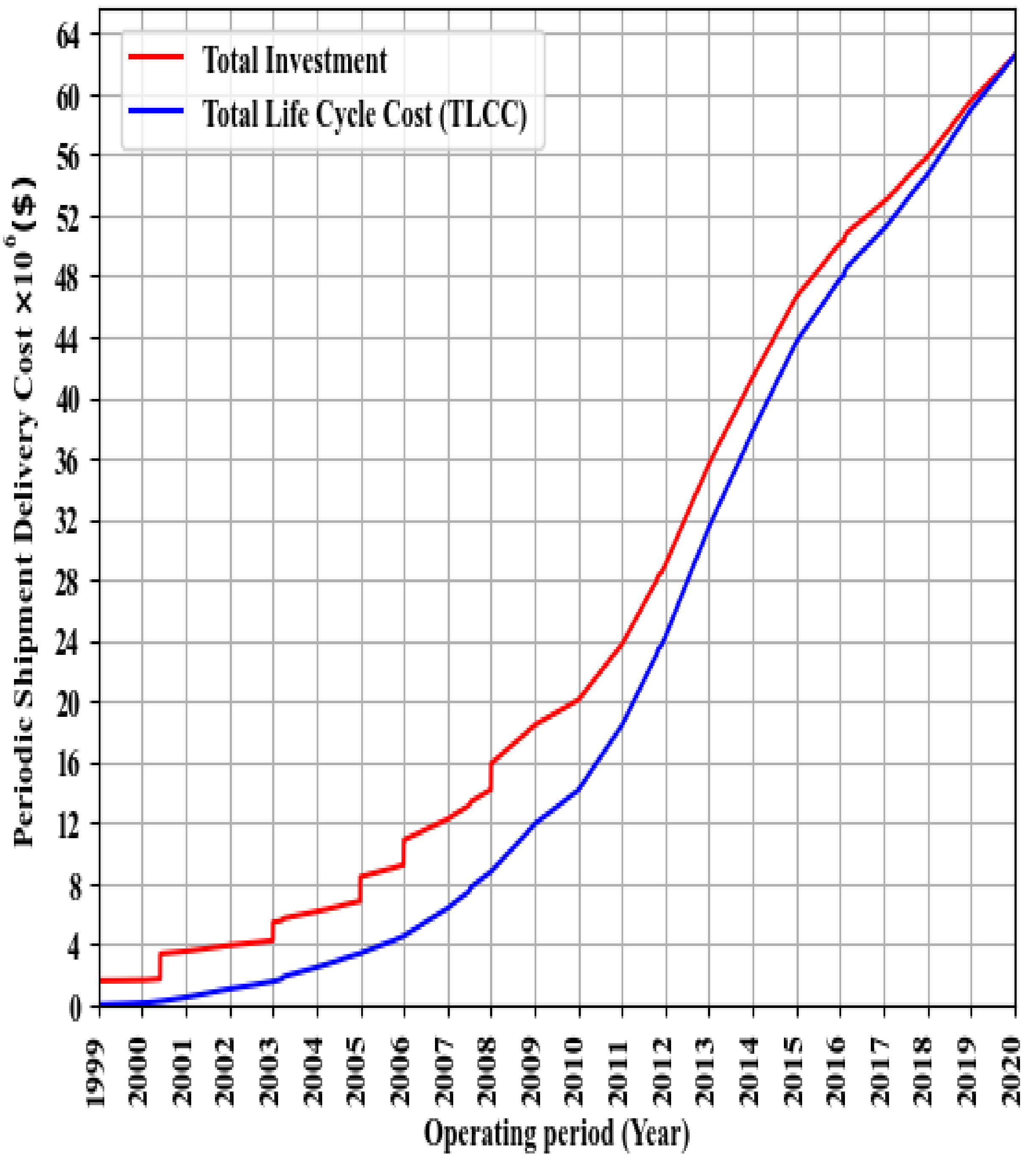

Figure 4.10: Comparison of the LNGFWA total life cycle cost with total investment

The result of the MAPE (MEA1) evaluation for the material flow balance was $\pm$0.0002%. Based on the Lewis (1982) MAPE classification, this result indicates excellent model material conservation and shows that at any operation period in the plant, the total feed gas input in the system $\left(\dot{V}^{TotNG}_{Feedt^*}\right)$ should be equal to the aggregate of the LNG output, finished product in inventory and materials that are work-in-process $\left(\dot{V}^{TotNG}_{Syst^*}\right)$. It can however be observed that in some cases, the $\dot{V}^{TotNG}_{Feedt^*}$ values are quite slightly lower than those of $\dot{V}^{TotNG}_{Syst^*}$. This was attributed to inaccuracies introduced by the use of various materials state conversion factors.

In addition, the two-tailed t-test analysis produced p-values of 0.5000 and 1.0000 for the variance (p^{Var}_{crt}) and means (p^{Means}_{crt}) respectively when $\dot{V}^{TotNG}_{Feed}$ and $\dot{V}^{TotNG}_{Sys}$ were compared. As such, the null hypothesis of MEA2 (H_0) was not rejected inferring that there was no significant difference in the input and the totality of the in-process and output materials.

Furthermore, the MEA1 analysis result for the comparison of the total LCC (C^{Tot}_{LCC}) and total investment (C^{Tot}_{Inv}) values at end of the operation period $(t^* = P_L)$ can be observed to intersect at $t^* = P_L$ as expected (Figure 4.10) indicating a balance in the monetary flows between the project's total investment and its total life cycle cost. C^{Tot}_{Inv} and C^{Tot}_{LCC} produced a MAPE of $\pm$0.0000 from their compared respective cost values of 62. 50 and 62.50 billion dollars indicating no difference in value between both quantities. This result is indicative of an exact balance in the SD-LNG-LCC financial flows and by extension an indication of the technical correctness of the model.

4.7 Model Results from Comparison with Case Study Data

The results of the comparative evaluation of the SD-LNG-LCC's outputs (LNG produced and shipped $\left[\dot{V}^{shipMod}_{Order}\right]$ and revenue $\left[\dot{G}^{Mod}_{Rev}\right]$) with those of the LNGFWA are shown as graphs in Figures 4.11 - 4.12 respectively. In addition, the results of the comparative evaluation of the model and firm's results based on the MEA1 are shown in Table 4.10 while Tables 4.11 and 4.12 show the results of the t-test results obtained via the MEA2 for LNG shipped and revenue accrued respectively.

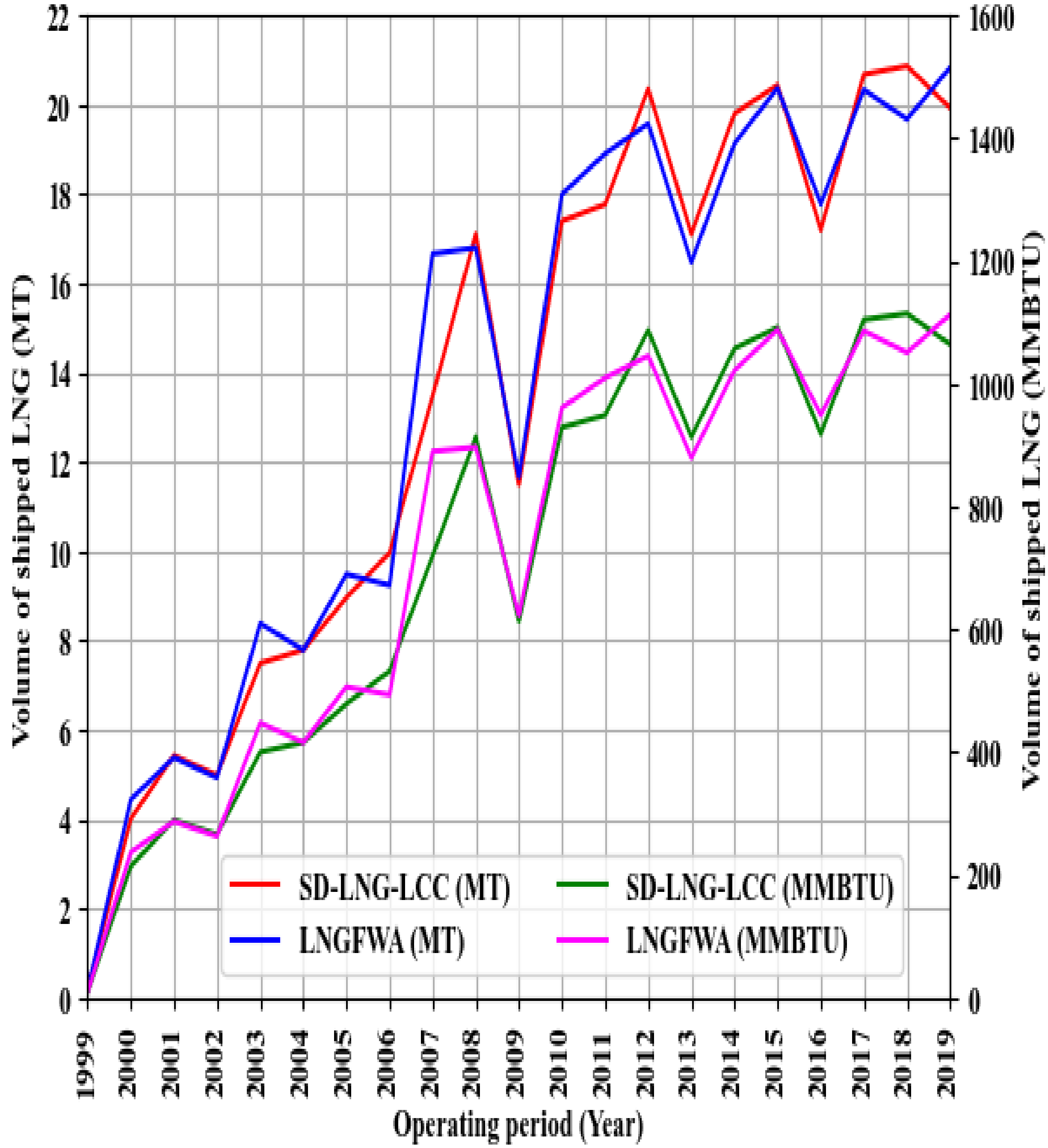

Figure 4.11: Comparison of the SD-LNG-LCC and LNGFWA outputs for the amount of LNG produced and sold between 1999 and 2019

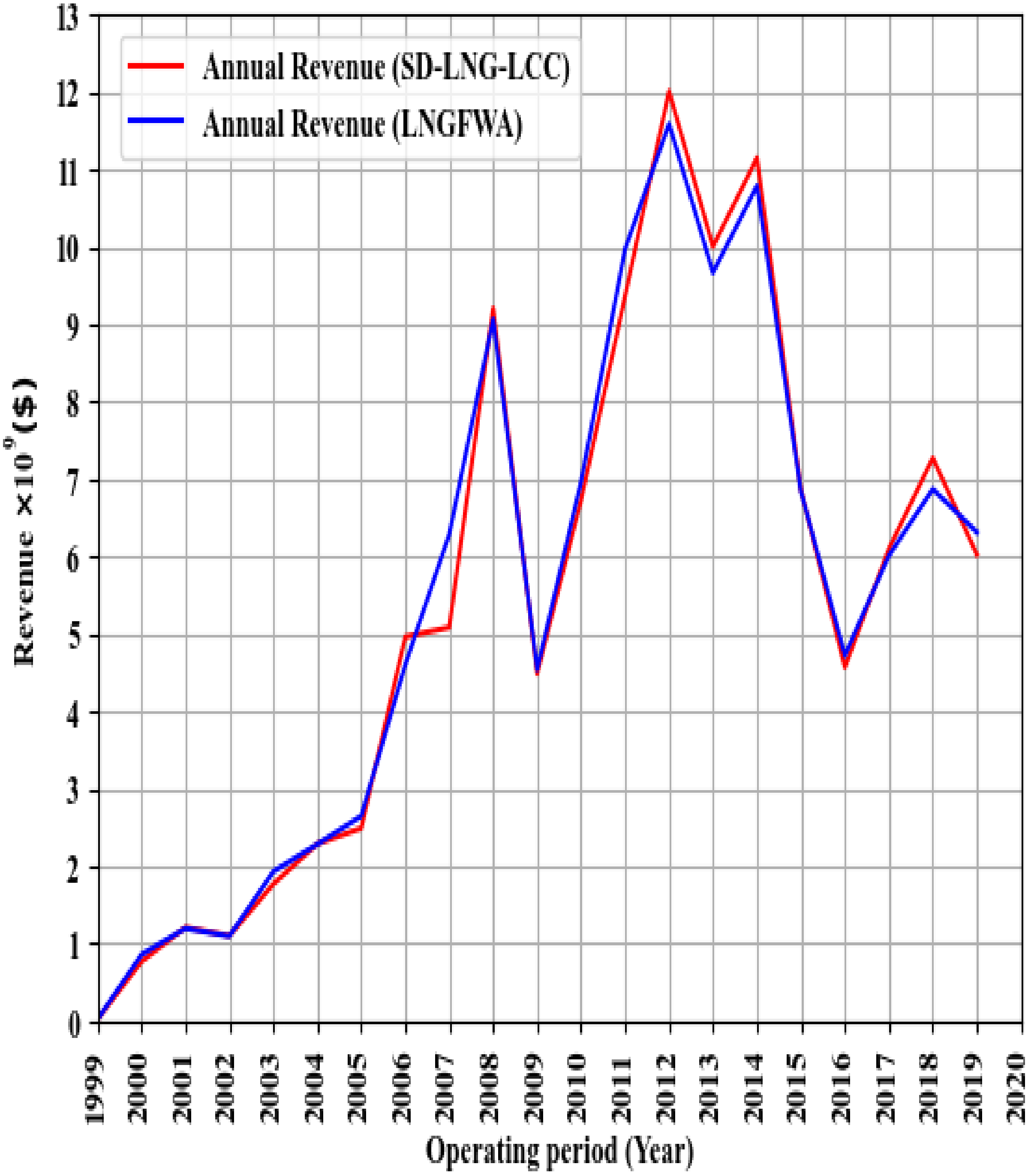

Figure 4.12: Comparison of the SD-LNG-LCC and LNGFWA revenue for LNG produced and sold between 1999 and 2019

Table 4.10: Comparison of the SD-LNG-LCC Outputs with the LNGFWA operational performance report in terms of the annual volume of LNG sold and revenue

Year	SD-LNG-LCC Outputs				LNGFWA Outputs					
	LNG Sold			Revenue	LNG Sold			Revenue	APE	APE
	MTPA	$\times 10^6$ MMBTU	$\times 10^6$ m^3	$\times 10^9$ (\$)	MTPA	$\times 10^6$ MMBTU	$\times 10^6$ m^3	$\times 10^9$ (\$)	LNG Sold	Revenue
1999	0.1898	10.1400	0.4222	0.0218	0.1900	10.1486	0.4222	0.0228	0.0843	4.4868
2000	4.0120	214.2947	9.8723	0.7690	4.4430	237.3160	9.8723	0.8571	9.7007	10.2813
2001	5.4297	290.0168	11.9655	1.2093	5.3850	287.6315	11.9655	1.1975	0.8293	0.9832
2002	4.9909	266.5817	10.9567	1.1029	4.9310	263.3818	10.9567	1.0967	1.2149	0.5608
2003	7.7069	411.6514	18.6426	1.7698	8.3900	448.1389	18.6426	1.9324	8.1420	8.4123
2004	7.7952	416.3702	17.3183	2.2893	7.7940	416.3045	17.3183	2.2837	0.0158	0.2470
2005	8.9662	478.9159	21.0846	2.4911	9.4890	506.8403	21.0846	2.6483	5.5095	5.9370
2006	9.9671	532.3798	20.5424	4.9625	9.2450	493.8075	20.5424	4.6015	7.8112	7.8446
2007	13.4757	719.7861	37.0319	5.0856	16.6660	890.1888	37.0319	6.2859	19.1423	19.0951
2008	17.1183	914.3486	37.3296	9.2064	16.8000	897.3462	37.3296	9.0668	1.8947	1.5397
2009	11.5009	614.3029	25.9307	4.4897	11.6700	623.3351	25.9307	4.5423	1.4490	1.1580
2010	17.3996	929.3750	39.9960	6.7286	18.0000	961.4423	39.9960	6.9681	3.3353	3.4371
2011	17.7745	949.3966	42.0180	9.3634	18.9100	1010.0486	42.0180	9.9724	6.0049	6.1069
2012	20.3605	1087.5240	43.5068	12.0140	19.5800	1045.8356	43.5068	11.5918	3.9861	3.6422
2013	17.1054	913.6611	36.5963	10.0051	16.4700	879.7197	36.5963	9.6683	3.8582	3.4835
2014	19.8077	1057.9976	42.5291	11.1530	19.1400	1022.3337	42.5291	10.7914	3.4885	3.3508
2015	20.4473	1092.1635	45.2844	6.8610	20.3800	1088.5663	45.2844	6.8431	0.3304	0.2616
2016	17.1964	918.5168	39.5072	4.5699	17.7800	949.6913	39.5072	4.7225	3.2826	3.2313
2017	20.6826	1104.7284	45.1955	6.1007	20.3400	1086.4298	45.1955	6.0137	1.6843	1.4467
2018	20.8716	1114.8245	43.7290	7.2740	19.6800	1051.1769	43.7290	6.8718	6.0549	5.8529
2019	19.9302	1064.5385	46.3065	6.0280	20.8400	1113.1365	46.3065	6.3149	4.3659	4.5432
Sum	282.7286	15101.5140	635.7653	113.4950	286.123	15282.8199	635.7653	114.2930	--	--
Mean	13.4633	719.1197	30.2745	5.4045	13.6249	727.7533	30.2745	5.4425	4.3898	4.5668

Table 4.11: t-Test results for the comparative evaluation of the SC-LNG-LCC output with those of the test data for the amount of LNG sold

	LNG Shipped (SD-LNG-LCC)	**LNG Shipped (LNGFWA)**
Mean ($\times 10^6$ MTPA)	13.4633	13.6249
Variance ($\times 10^{13}$MTPA^2)	43.1728	42.3443
Standard Deviation ($\times 10^6$)	6.5706	6.5073
Observations	21	21
Pooled Variance ($\times 10^{13}$MTPA^2)	42.7586	
Hypothesized Mean Difference	0.0000	
Degree of Freedom	40	
t Stat	-0.0801	
P(T<=t) one-tail	0.4683	
t Critical one-tail	1.6839	
P(T<=t) two-tail	0.9366	
t Critical two-tail	2.0211	

Table 4.12: t-Test results for revenue accrued on the comparative evaluation of the SC-LNG-LCC output with those of the test data

	Annual Revenue (SD-LNG-LCC)	Annual Revenue (LNGFWA)
Mean ($\times 10^6$ \$)	5.4045	5.4425
Variance ($\times 10^{19}$ \$^{2})	12.8033	12.2758
Standard Deviation ($\times 10^6$ \$)	3.5782	3.5037
Observations	21	21
Pooled Variance ($\times 10^{19}$ \$^{2})	12.5395	
Hypothesized Mean Difference	0.0000	
Degree of Freedom	40	
t Stat	-0.0348	
P(T<=t) one-tail	0.4862	
t Critical one-tail	1.6839	
P(T<=t) two-tail	0.9724	
t Critical two-tail	2.0211	

4.7.1 Capital expenditure

Five different CAPEX injections were made by the LNGFWA into the LNG project over the study timeline with eighty percent of these investments being dedicated to Brownfield expansions. The total project CAPEX from 1999 – 2019 arrived at via the SD-LNG-LCC model amounts to 9.38 billion dollars of which 62.09% was utilised for Brownfield project implementation.

The real-time total CAPEX of the LNGFWA as reported is $9.34 billion (Nigerian Liquefied Natural Gas, 2020). Thus the actual difference and Absolute percentage difference between the SD-LNG-LCC model results with real-time data were gotten as 25.36 million dollars and 0.27% respectively. This indicates that the model's CAPEX estimation approach high degree of accuracy. As a result of constraints to the maximum production and the different periodic plant capacities caused by multiple Brownfield expansions within the study period, the actual average operating capacity of the plant was determined to be 13.46 MTPA.

This caused the resulting CAPEX per TPA of the plant to be 696.86 $/TPA. Based on the 21-year study period and 12% rate of return, the straight-line depreciation/amortization of the CAPEX was obtained as 0.62 $/TPA. It is worth noting that these values are expressed in the dollar values of the period in which the CAPEX was made available. When expressed in the dollar value of the 2014 base evaluation period employed for comparative analysis in this study, the CAPEX value was $12.11 billion (899.97 $/TPA).

4.7.2 Liquefied natural gas shipped and corresponding accrued revenue

As can be observed from Figure 4.11, the shipped/sold LNG volumes show a fluctuating upward trend. This implies that the organisation over the study period actively increased its LNG sale volume. The impact of this can be observed in the corresponding upward trend of revenues that accrued to the organisation (Figure 4.12).

The amount of annual LNG shipment produced by the SD-LNG-LCC when compared with those made by the organisation within its twenty-one years of operations shown in Table 4.5 for the model, a total of 282.73 MT (15.10×10^3 MMBTU) of the product was shipped off within this period. This corresponds to a mean value of 13.46 MTPA (719.12 million

MMBTU) and implies that the firm was able to attain 78.64% of the plant-designed throughput.

These values closely match the actual values of 286.12 MT (15.28 billion MMBTU) and 13.62 MTPA (727.75 billion MMBTU) for the total and average amount of LNG sold over this period as reported by the firm. In terms of the MEA1, the MAPE of the SD-LNG-LCC outputs on the volume of LNG shipped as compared with the corresponding LNGFWA's data was 4.390 (Table 4.10) while the p-value from the MEA2 analysis ($p_{crt}^{mean} = 0.9366$) (Table 4.11).

Regarding the evaluation on the basis of the revenue accrued, the results obtained show similar behaviour to those of the LNG sold. Firstly, the trend of the annual revenue over the study period was observed to also be fluctuating, upward and increasing. However, there was a sharp revenue drop in 2009 as well as in the periods between 2016 and 2019 (Figure 4.12). The 2009 revenue drop could be attributed to a lowered LNG sale rate brought about by a drop in the firm's operational capacity. However, between 2016 and 2019 the drop in revenue resulted from low LNG sales prices. The total revenue generated from the project obtained from the SD-LNG-LCC and a published source (Nigerian Liquefied Natural Gas, 2020) is 113. 50 and 114.29 billion dollars respectively. The MAPE of the comparison of the model's annual revenue result and the corresponding firm's data was 4.567 while the t-test result for significant differences produced a p-value of 0.9724 (Table 4.12).

The results of the comparative evaluation for both the annual amount of LNG shipped and annual revenue accrued show that in terms of the MAPE, the SD-LNG-LCC excellently approximates the real-time results of the firm given the limits of input data deployed. Furthermore, the p-value results indicate that the null hypotheses are not rejected in both test cases as there are no observable significant differences between the model's output and those of the real-time data of the organisation.

4.8 Life cycle cost analysis of the system of study

The effect of the LNG operation cost driver inputs on the current LCC and by extension the performance state of the LNGFWA is done in this section. The LCC results that are presented and discussed are based on the expenses incurred by the organisation during liquefaction operations, maintenance operations and labour utilisation.

4.8.1 Liquefaction material usage cost

The liquefaction material usage costs are those that can be directly tracked to the cost attributed to the feed gas usage and energy expenditure and are influenced by internal factors (availability of the feed gas, feed gas utilisation rate, plant availability and the labour cost) and external factors (feed gas purity, the market demand for the firm's LNG and the cost of the feed gas supply to the plant).

Figure 4.13 shows the availability profile for the LNGFWA LNG plant as well as those of some equipment contributors while Table 4.13 shows the ranges, means and standard deviations of the availability of different process equipment and the overall LNG production system. The impact of market demand as an external plant feed utilisation bottleneck is shown in Figure 4.14. Figure 4.15 displays the results of the annual feed gas utilisation cost of the organisation in terms of total tonnage capacity and MMBTU while the gas purchase cost to LNG sale price profile is shown in Figure 4.16.

4.8.1.1 Effect of influence of internal factors

The feed gas was considered to be always available and accessible as long as the gas supply system remained functional. This was necessary given that the final investment decision (FID) made on the feasibility of the project was based on the assurance of gas supply availability throughout the entirety of its operations. From an annual perspective, it appears from existing reports (Department of Petroleum Resources, 2018, 2019) that the activities for which feed gas supply are utilised do not take into consideration the fraction which is usually set aside as fuel gas. This by implication means that 100% plant operation energy cost savings are made by the firm as a result of the use of fuel gas for LNG processing at zero cost.

This policy is both cost effective and environmental friendly. About 193.6BScm of the feed gas used for LNG production are associated gas [AG] (Nigerian Liquefied Natural Gas, 2020) which is produced during crude oil production processes and which should otherwise have been flared (Department of Petroleum Resources, 2019).

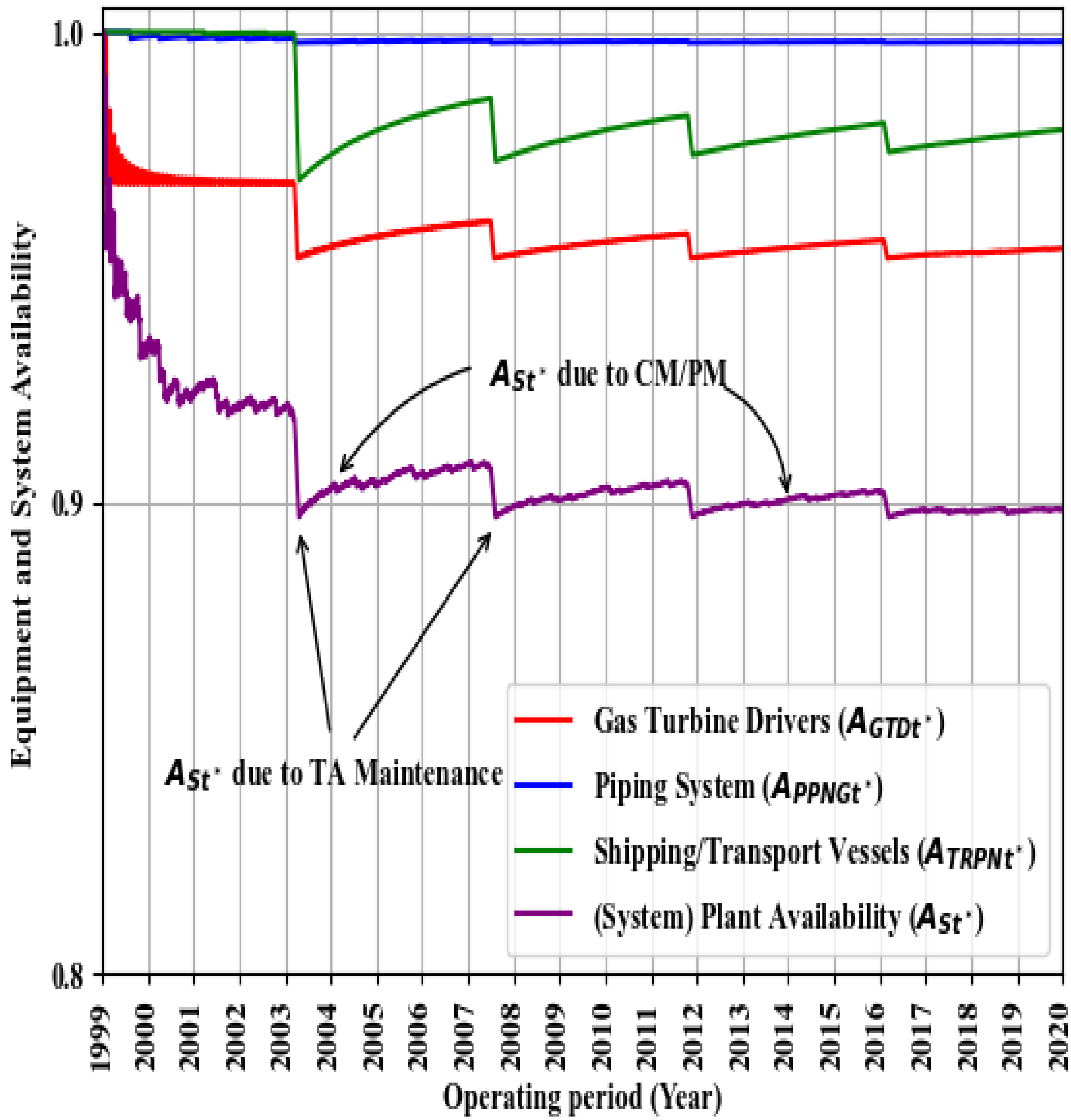

Figure 4.13: Availability profiles for three LNG process equipment and that of the system

Table 4.13: Daily and annual Range, mean and standard deviation of equipment and system availability values

Equipment Type (k_j)	Daily Availability (%)			Annual Availability (%)		
	Range	Mean	Standard deviation	Range	Mean	Standard deviation
Compressors/Expanders (Type 1) $[CT_1]$	99.01-100	99.27	0.27	99.02-99.73	99.26	0.24
Compressors/Expanders (Type 2) $[CT_2]$	96.54-100	97.42	0.90	96.57-99.17	97.38	0.85
Gas Turbine Drivers $[GTD_j]$	95.18-100	95.77	0.65	95.20-96.88	95.73	0.56
Natural gas pre-cooling heat exchangers $[PCHE_j]$	98.32-100	98.78	0.48	98.61-100	98.98	0.40
Main cryogenic heat exchangers $[MCHE_j]$	98.60-100	98.99	0.42	98.61-100	98.98	0.39
Gas separators (Type 1) (GST_1)	97.83-100	98.00	0.14	97.83-98.19	97.98	0.10
Gas separators (Type 2) (GST_2)	99.36-100	99.52	0.17	99.37-99.88	99.52	0.16
Valves $[VLVS_j]$	99.44-100	99.63	0.19	99.44-100	99.62	0.19
Gas treatment heaters $[GTHS_j]$	97.96-100	98.43	0.51	97.98-99.22	98.39	0.42
Piping $[PPNG_j]$	99.78-100	99.82	0.04	99.78-99.91	99.81	0.03
Ships and transport vessels $[TRPN_j]$	96.84-100	98.62	0.90	97.40-100	98.23	0.89
Others (sensors, fire/gas detectors, pumps, etc.) $[OTHR_j]$	99.02-100	99.30	0.29	99.02-100	99.29	0.28
System	89.68-100	90.69	1.29	89.73-93.30	90.57	0.57

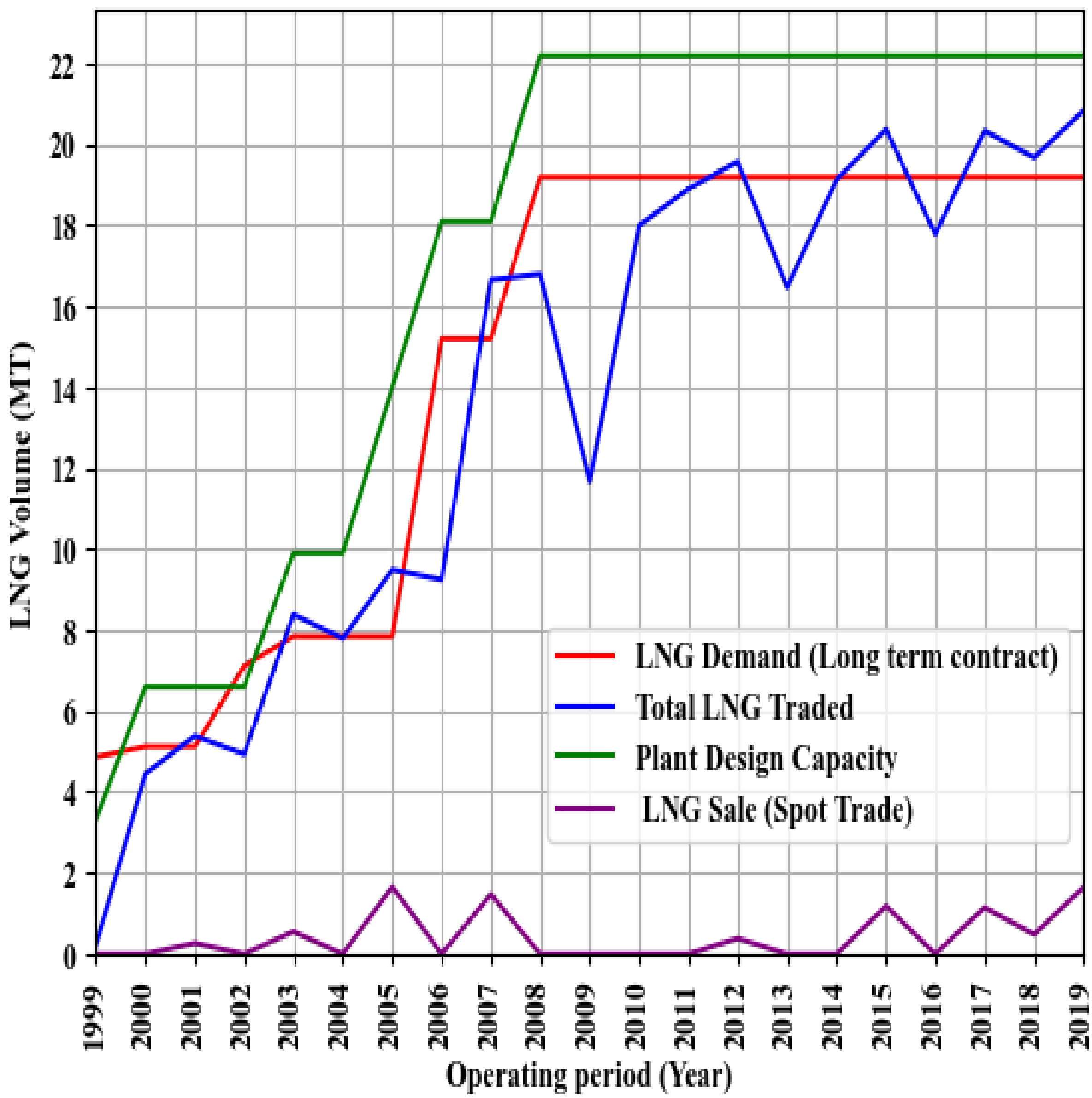

Figure 4.14: LNG Market demand for the LNGFWA product versus its corresponding supply profile.

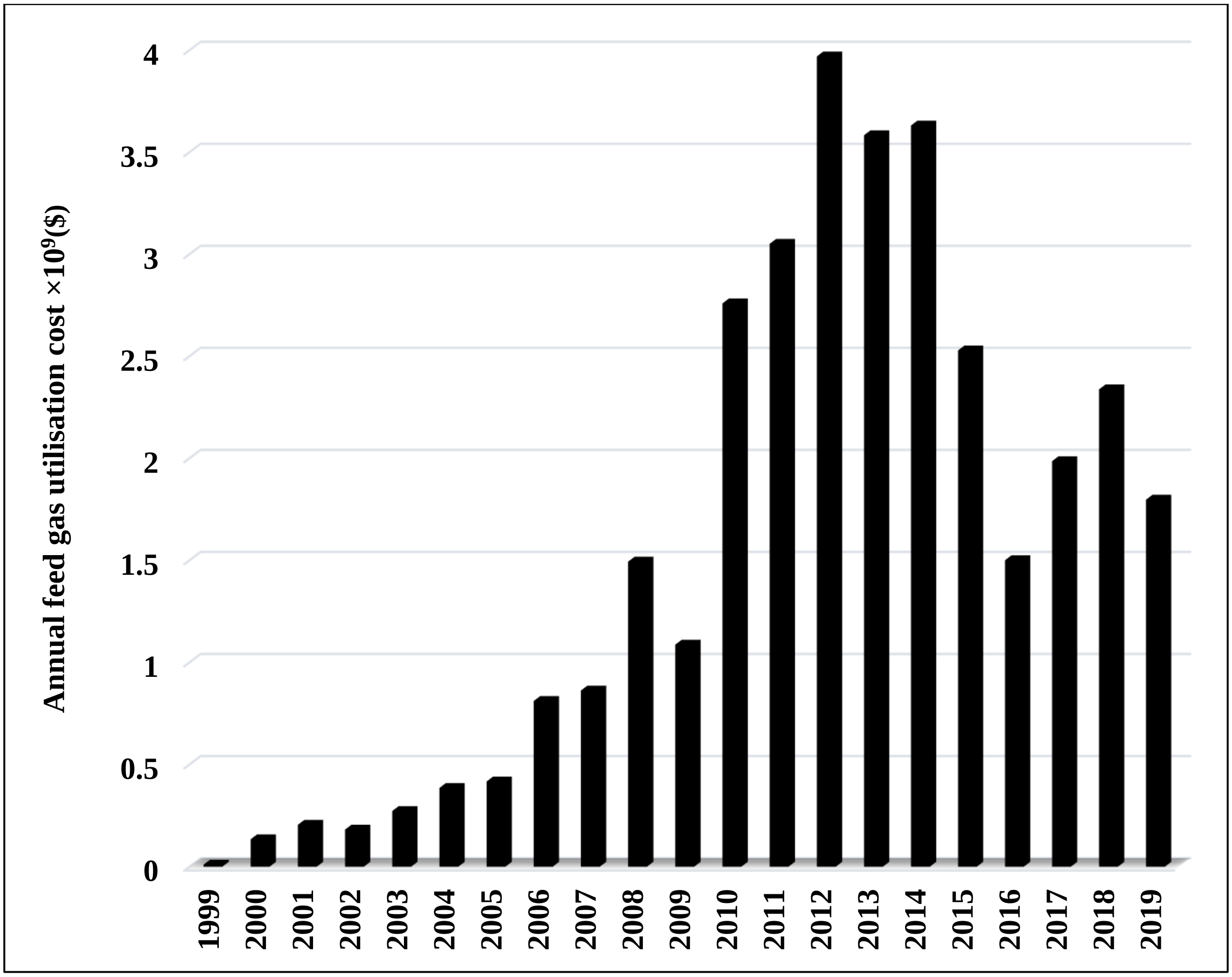

Figure 4.15: Periodic (annual) feed gas usage cost incurred by the firm

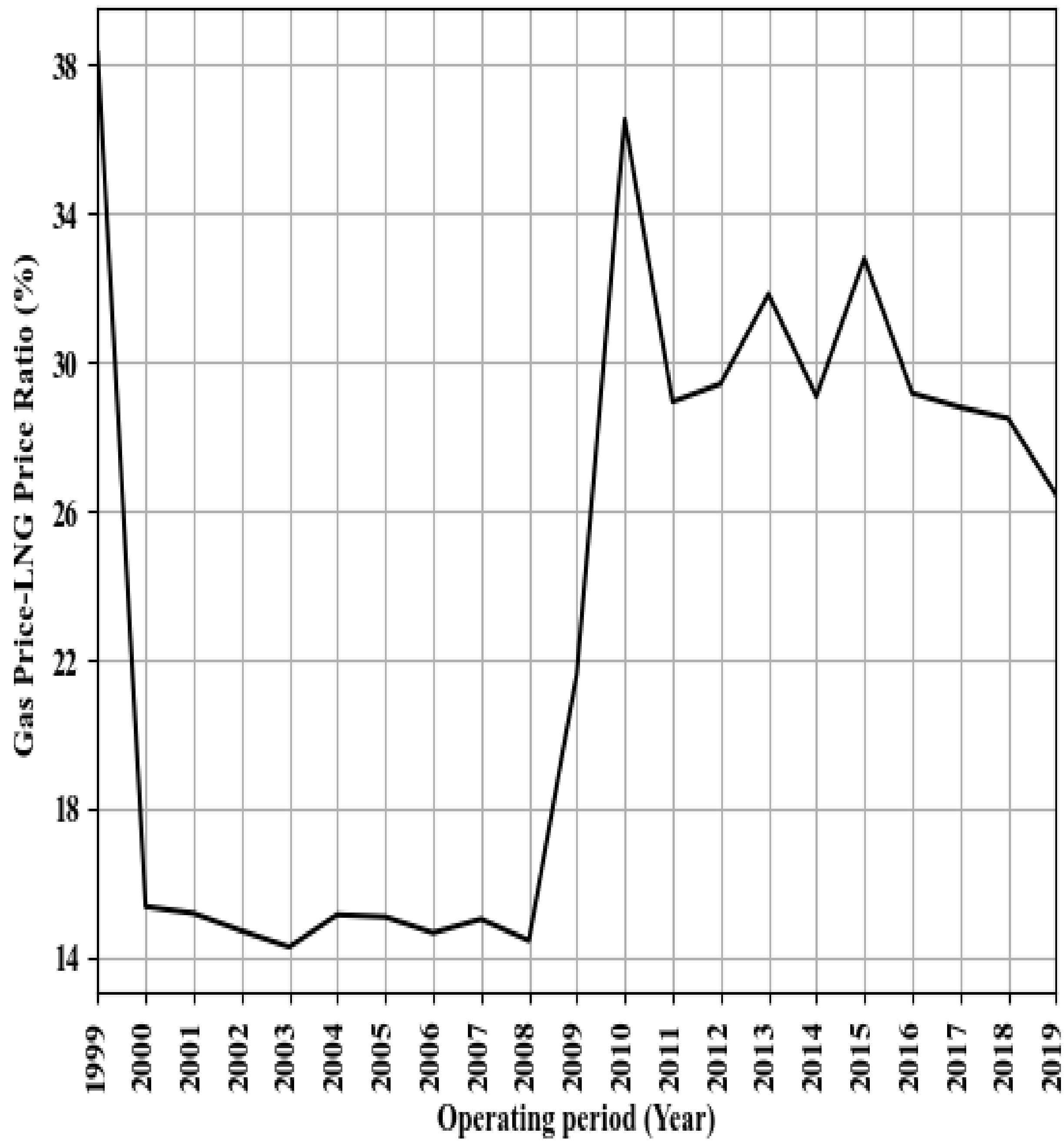

Figure 4.16: Gas pricing policy profile of the LNGFWA

It is also on record that currently, at least 10% of the total associated gas produced annually cannot be effectively utilised and as such is still being flared. Due to the monetary penalties imposed on gas flaring by regulatory bodies (placbillstrack, 2020), it is understandable that the suppliers of feed gas from AG supply sources would rather provide shrinkage to the LNG firm at little or no cost rather than incur costs associated with flaring activities and flaring penalties.

Another major factor that affects the extent of feed gas utilisation is the plant availability (A_{st^*}). A_{st^*} results from the interaction of the availability states of each piece of equipment involved in the liquefaction process. From the results obtained, all equipment considered were largely available within the study period.

Based on daily operation periods, the least available (Gas turbine [*GTD*]) had a daily range and average availability value of 95.18 - 100% and 99.82% respectively. Also, the daily range and mean availability value ranges for the most available equipment (piping systems [*PPNG*]) were 99.78 - 100% and 99.82%, respectively.

A cross-section of the system availability profile and those of some equipment (Figure 4.13) show that the availability of the liquefaction plant was largely impacted by maintenance actions from CM/PM or turnarounds activities. The impact of the high availability of the equipment on the process ensured a daily plant availability range and mean values of 89.68% - 100% and 90.69% (Table 4.13). This result lies above the minimum expected availability threshold for LNG plants (90%) and falls well within the industry range of 92.6 ± 2.2% (Malaret, 2015; Hassan *et al.*, 2016). In terms of the speed of intervention responses to system disruptions at instances where equipment failure occurred, it was observed that the mean value of the maintenance action to downtime ratio was 0.9982 signaling that prompt responses were made in the system to ensure continual plant uptime. It can thus be inferred that generally, very few equipment failure-related disruptions were experienced during operations.

4.8.1.2 Effect of influence of external factors

Regarding external or non-plant-based factors, the reported average purity of the feed gas used by the LNGFWA is 91.60%. This value cannot be influenced by the liquefaction plant conditions as it is dictated by LNG upstream process factors. Thus for every unit volume of feed gas used, 8.4% of the content is non-usable for LNG production. Another external bottleneck to the feed utilisation cost was observed to be the plant design capacity. It can be seen in Figure 4.14 and Figure 4.15 that a positive correlation exists between changes between the varying plant design capacities and the volume of feed gas used. Thus given that all other conditions do not change, the cost of feed utilisation is likely to exhibit a proportionate increase given an increase in the plant capacity.

The effect of increased plant capacity on feed utilisation cost is more emphasized by the observation that most of the firm's expansion projects were done to accommodate increases in market demands from completed sales and purchase agreements. As an example, it can be observed from Figure 4.14 that in 2000, LNG production from new a Brownfield expansion project became existent to accommodate an increase in demand (and by extension increases in expected feed gas volume) for the firm's product made in 1999. This behaviour can also be observed in 2003 and 2008. However, it can be observed also that from 2008 to 2019, apart from small volumes of spot trading the firm's plant capacity has remained unchanged due to the lack of further increases in market demand for the firm's product.

Another significant external factor driver of the feed gas utilisation cost is the cost of the feed gas. As revealed from Figure 4.4, the price charged for a unit MMBTU of feed gas varied in value from one year to another and thus impacted the overall cost of feed utilisation. The policy that governs the rate at which feed gas is charged differs between projects, regions and countries (International Energy Agency, 2003; Songhurst, 2018).

However, comparing feed gas cost and LNG sale price, reveal similar profiles suggesting an LNG sale price-based feed gas pricing policy for the LNGFWA. A further investigation of this relationship shows that feed gas prices are charged at a somewhat fixed rate of the LNG sale price. Based on the method of averaging, two unit feed gas pricing rate regimes were observed (Figure 4.16). The first regime of approximately 15% of the unit LNG price was observed to exist between 1999 and 2008. It appears the rate was increased to 30% from 2009 as captured by the second pricing rate regime.

With consideration given to these internal and external feed gas usage costs, the annual material usage cost was observed to be in the range of $9.67×10^{6} to $3.97×10^{9} (Figure 4.15) with the latter value occurring in 2012 when the feed utilisation in the plant was relatively high and the LNG price was at its highest. The total material usage cost was $33.02 billion. In terms of the annual cost per unit product volume produced and unit energy produced respectively, this value resolves to 116.79 $/TPA and 2.19 $/MMBTU respectively.

4.8.2 Maintenance material management cost

The maintenance material management costs are those expenses that were incurred from inventory utilisation occurred from equipment maintenance inventory utilisation, inventory ordering and inventory holding activities. The profile and breakdown of the result of the inventory utilisation cost are shown in Figure 4.17 and Table 4.14 respectively. Figure 4.18 shows the percentage material usage cost contributions of the different equipment involved in the liquefaction process while Table 4.15 provides a summary of the maintenance material management cost for the LNGFWA.

As was previously anticipated as mentioned in section 4.6.4.3, the actual cost of spare parts usage within operation periods was observed to vary for the number of maintenance interventions, the cost incurred per intervention, the plant capacity at different operation periods and inflationary factors. The periodic IUC behaviour for all equipment considered generally followed a typical profile of fluctuations and an increasingly positive trend as shown in Figure 4.17. It can be seen in the figure that over the study period, the IUC is slightly upward trending. This was attributed to the fallout in increases in the IUC due to the different influencing factors previously mentioned. However, more significant spikes in increases can be observed in 2003, 2007, 2011 and 2016 when turn-around (TA) maintenance activities were scheduled.

The total cost of inventory utilisation was observed to be $2.92 billion (Figure 4.16). From this amount, the maximum intervention cost ($644.56×10^{6}) was incurred on pre-cooling heat exchanger $\left(PCHE_j\right)$ maintenance and while the least cost ($2.27×10^{6}) was incurred on the maintenance of the gas heating and treatment equipment $\left(GTHS_j\right)$.

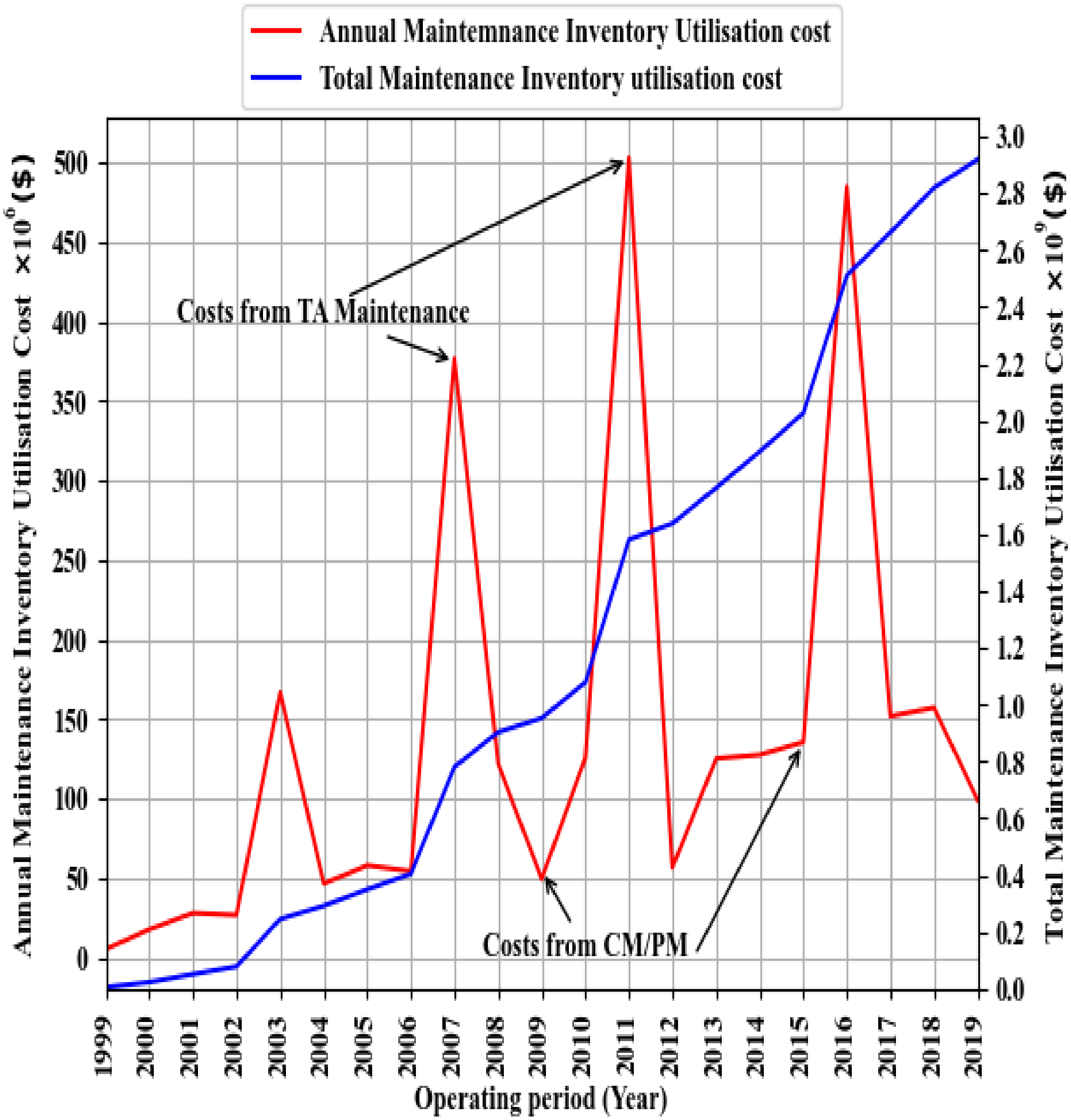

Figure 4.17: Profile of the periodic and total maintenance inventory utilisation cost incurred by the LNGFWA

Table 4.14: Breakdown of the LNGFWA actual inventory utilisation cost

Equipment (E_k)	Class (j)	Expected MIC by Equipment Total $[\$/Tonne]$			Expected MIC by number of interventions				Expected MIC by Annual values			
		CP/PM	TA	Total	Expected total MI		Cost per MIC per unit plant capacity $[\$/TPA]$		Expected Annual MI frequency $[Year^{-1}]$		Annual MIC per Unit Capacity $[\$/TPA]$	
		C_{CPm}^{Int}	C_{Ta}^{Int}		$N_{CPmkt^*}^{Int}$	$N_{Takt^*}^{Int}$	$C_{CPmkt^*}^{PerInt}$	$C_{Takt^*}^{PerInt}$	N_{CPmk1}^{Int}	N_{Tak1}^{Int}	C_{CPmk1}^{Int}	C_{Tak1}^{Int}
CT_j	1	0.929	0.481	0.898	40	4	0.024	0.12	1.90	0.19	0.034	0.024
	2	33.868	18.236	34.366	74	4	0.51	4.559	3.52	0.19	1.315	0.927
GTD_j	1	35.381	0.359	32.766	230	4	0.161	4.331	10.95	0.19	1.237	0.881
$PCHE_j$	1	23.813	0.111	35.163	14	4	1.701	5.191	0.67	0.19	1.224	1.055
$MCHE_j$	1	13.511	17.325	18.599	14	4	0.965	2.589	0.67	0.19	0.719	0.526
GST_j	1	0.74	0.068	0.687	570	4	0.001	0.09	27.14	0.19	0.026	0.018
	2	0.189	10.355	0.204	34	4	0.007	0.028	1.62	0.19	0.008	0.006
$VLVS_j$	1	0.289	20.763	0.517	5	4	0.072	0.078	0.24	0.19	0.018	0.016
$OTHR_j$	1	6.789	5.814	9.944	14	4	0.485	1.454	0.67	0.19	0.349	0.296
$GSTH_j$	1	0.128	10.288	0.125	24	4	0.006	0.017	1.14	0.19	0.005	0.003
$PPNG_j$	1	17.048	3.646	18.036	29	4	0.675	2.572	1.38	0.19	0.643	0.523
$TRPN_j$	1	4.443	0.312	7.274	14	4	0.342	0.911	0.67	0.19	0.299	0.183
Total	--	137.128	87.758	158.578	--	--	4.949	21.940	--	--	5.877	4.458
Grand Total		224.886			26.889				10.335			

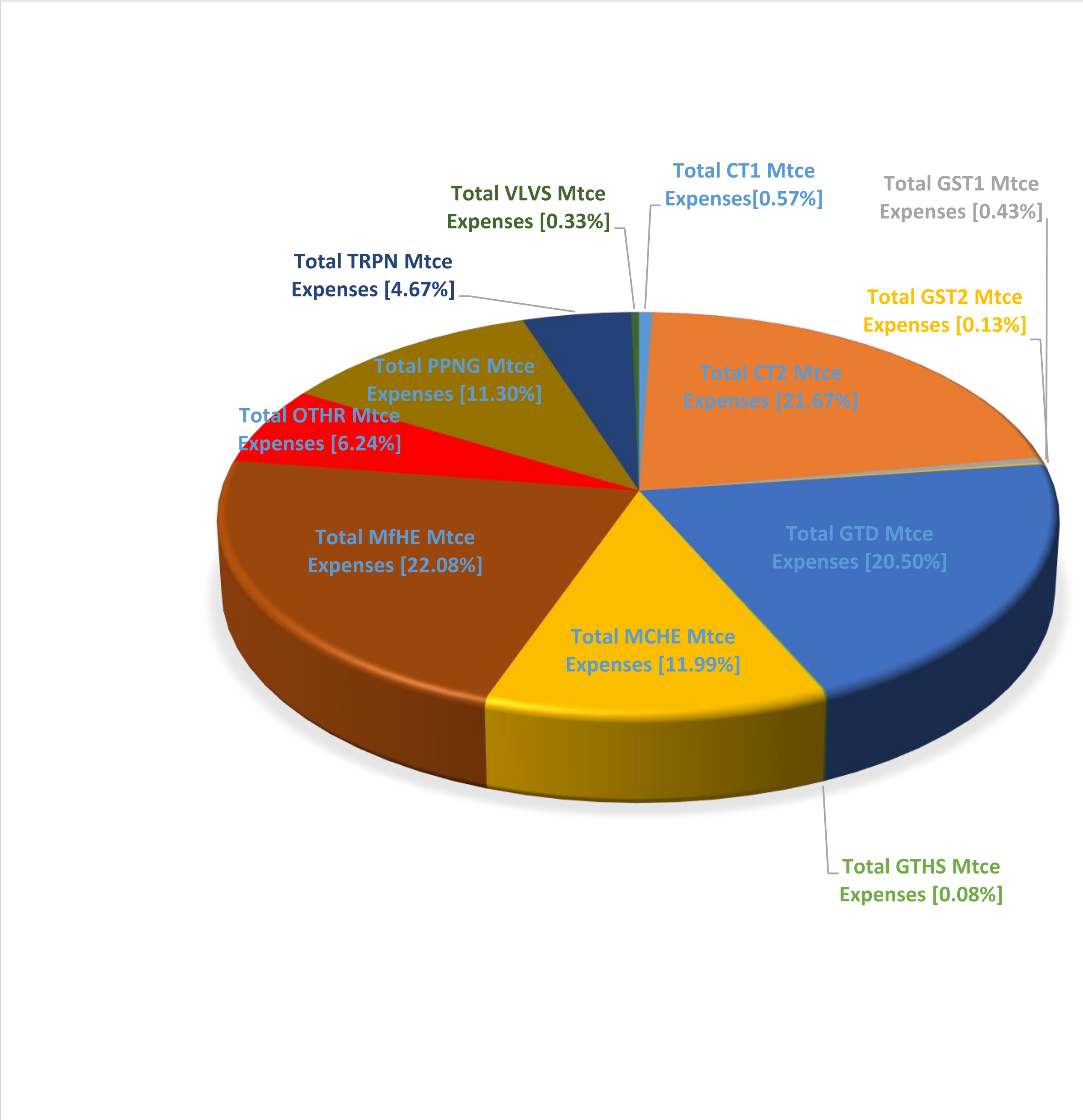

Figure 4.18: Equipment percentage contributions to the maintenance inventory utilisation cost

Table 4.15: Summary of the cost elements which constitute the total cost of maintenance material management incurred by the LNGFWA

SN	Cost Quantity	Cost Value
1	Total cost of maintenance inventory utilization ($\times 10^9$ \$)	2919.58
2	Total inventory ordering cost ($\times 10^6$ \$)	290.22
3	Total Inventory holding cost ($\times 10^6$ \$)	215.30
4	Total maintenance material management cost ($\times 10^6$ \$)	3425.09
5	Mean Annual maintenance material management cost ($\times 10^6$ \$/Year)	163.10
6	Maintenance material management cost per unit operating capacity (\$/TPA)	12.12
7	Maintenance material management cost per unit energy produced (\$/MMBTU)	0.23

Furthermore, it was observed that more than 75 percent of the IUC incurred was expended on the maintenance of the compressors, gas turbines and heat exchangers (Figure 4.18). The cost of ordering inventory taken as 15% of the cost of individual orders was obtained as $\$290.21 \times 10^6$, while the annual inventory holding cost taken as 25% (Azzi *et al.*, 2014; Odedairo *et al.*, 2020) resulted in a total of $\$215.30 \times 10^6$.

Thus in total, the maintenance material management cost incurred within the study window was 3.43 billion dollars. This amount averages a total maintenance expenditure of $\$163.10 \times 10^6$ per annum. This value lies well within the annual maintenance expenditure range of $\$140 \times 10^6$ to $\$470 \times 10^6$ for many LNG production organisations existing in various regions around the world (Songhurst, 2018).

However, given that these organisations differ in terms of their design and operating capacities, a clearer depiction of their maintenance intervention expenses can be expressed in terms of expenses incurred per operating capacity in TPA and for the LNGFWA, this resulted in a value of 12.123 $\$/TPA$ (0.227 \$/MMBTU). This value is expected to be different from one plant to another depending on the conditions of project locations, process complexities and actual operating capacities. For example, under the assumption of a 100% operating capacity, Case Projects 1-3, located in Australia cost about 30, 30 and 19 $\$/TPA$, while case project 4 located in the USA cost 7.83 $\$/TPA$ (Songhurst, 2018).

4.8.3 Labour Cost

The labour cost essentially comprises the expenses made by the organisation on the human resources utilised in production and maintenance operations over the study period. In both cases of production and maintenance labour, the costs incurred are directly related to the wage rate which the firm is willing to pay for personnel service and the number of personnel involved in the specific operation. The time-influenced wage rate estimate for all operations is shown in Figure 4.19 while the workforce number and cost profiles are shown in Figure 4.20.

For both liquefaction and maintenance operations, the LNGFWA average annual wage rate of a permanently employed worker for process and mechanical engineers averaged 12 million Naira (engineerforum, 2022; Recruitment Zilla, 2022).

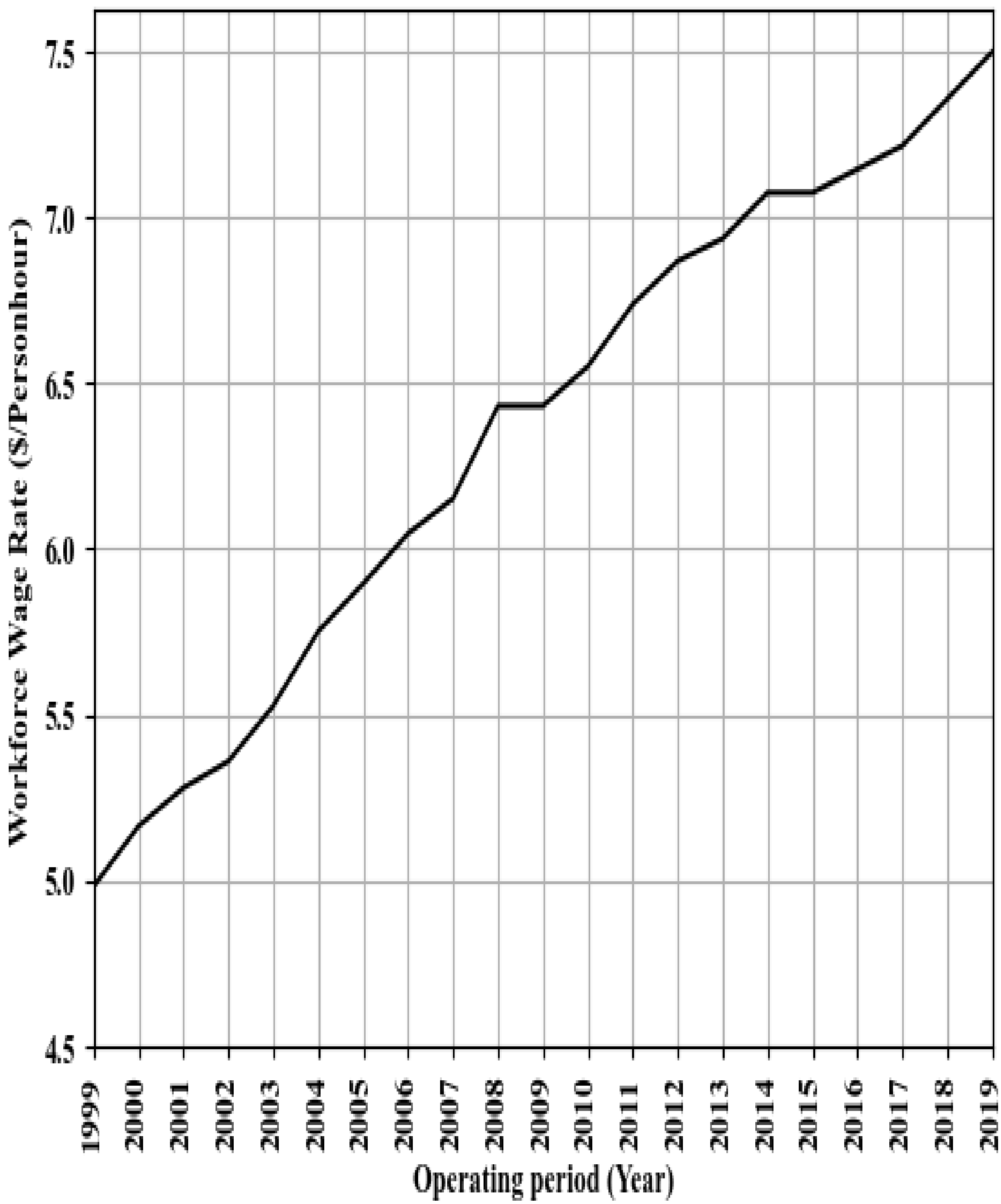

Figure 4.19: Workers' wage rate for production and maintenance operations

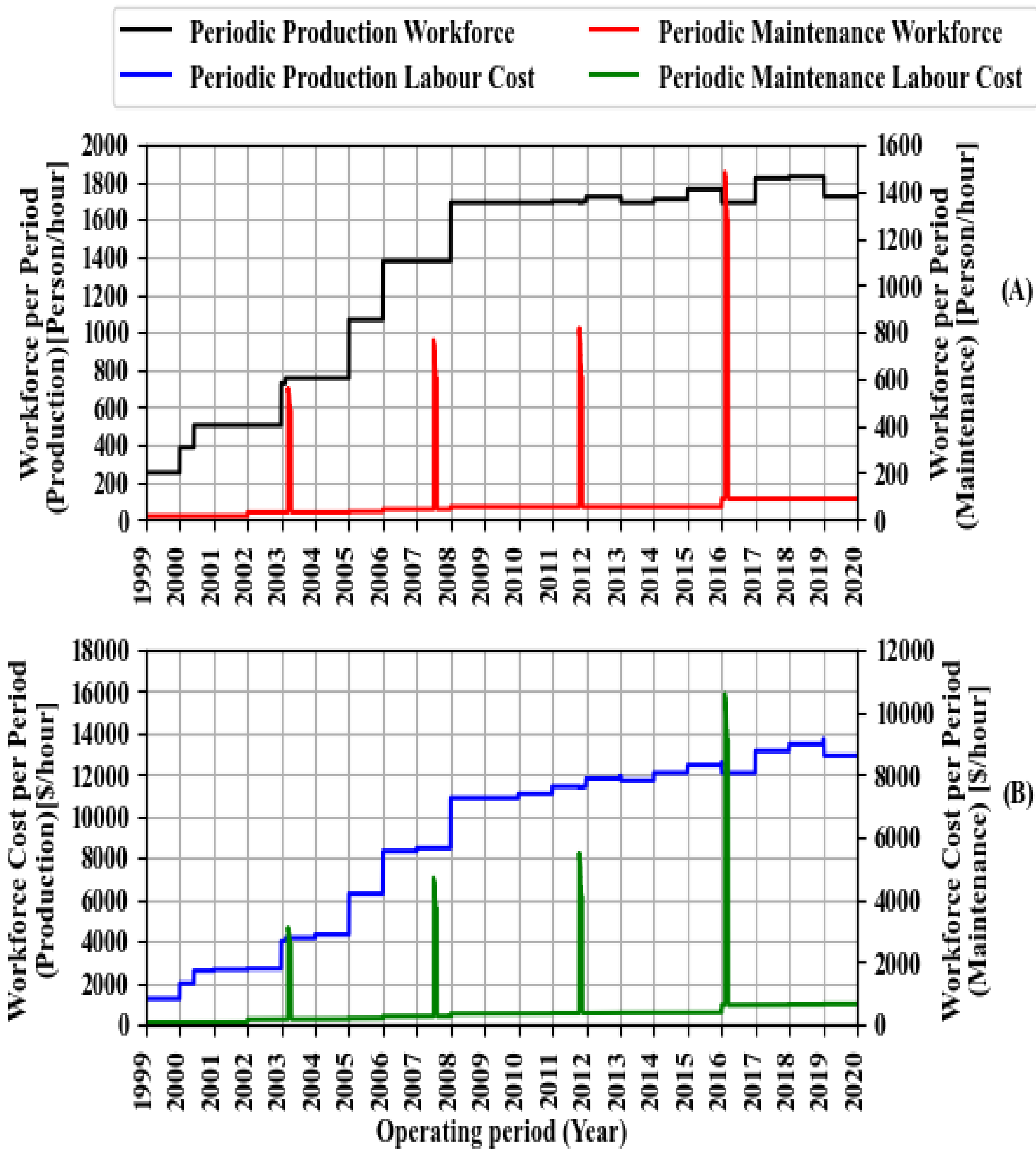

Figure 4.20: Periodic workforce and periodic workforce cost profiles for production and maintenance operations

This results to \$60000 when converted at the approximated value of ₦200 to \$1 exchange rate in 2014 (Exchange Rates UK, 2022). A value of \$120,000 was however adopted to account for other responsibilities to staff including insurance, on-site housing, and health care while \$40,000 was adopted for contract/non-permanent staff (Table 4.2).

Based on the fraction of permanent and contract staffing structure of the organisation, the base evaluation period value of the annual wage rate per worker was \$57040 (Table 4.2). Given the impact of inflationary factor effects on the wage rate in periods before and after the base evaluation period, the hourly wage rate per worker for production and maintenance operations ranged between \$4.98 and \$7.49 (Figure 4.19).

As expected, the total workforce number for production operation at any period is dictated on the one hand by the production workforce capability (K^{WC}), production workforce productivity (θ_{Prod}), the facility location factor (f^{Loc}), the plant operational capacities at different periods and the constraint placed by the budget capability on the workforce number. θ_{Prod} was taken as unity, while f^{Loc} was deemed to be unity as the location of the LNGFWA facility as well as its process complexity relative to other projects from a global perspective was considered normal. K^{WC} was determined to be $2310.92 \times m^3 gas/Manhour$ based on 70 production workers employed to convert 1 MTPA of feed gas to LNG (Table 4.16). This implied that about 2300 cubic metre of feed gas per hour was expected to be converted by a production operation personnel in the study period.

These quantities caused the observed number of production workforce throughout the study period to fall between 251 (at the minimum plant capacity) and 1722 (at the maximum plant capacity) corresponding to a minimum, maximum and average periodic production workforce cost of values of 1250.30 \$/hour, 13713.50 \$/hour (Figure 4.19) and \$8783.86 \$/hour (Table 4.16) respectively. The total production cost incurred by the firm within the study window amounted to 1.49 billion dollars implying an average cost of \$5.26 per TPA (Table 4.16).

Regarding the equipment maintenance workforce cost, the number of maintenance personnel ranged between 16 and 89 throughout the observation period except during TA maintenance when the number rose to values between 444 and 1482 (Figure 4.20A).

Table 4.16: Workforce cost breakdown for the production and maintenance operation sub-sectors

SN	Quantity	Production	Maintenance		Production and maintenance
			CM/PM	TA	
1	Workforce Wage rate ($\$/Manhour$) [Minimum and Maximum]	--	--		\$4.98/\$7.49
2	production workforce capability ($m^3 gas/Manhour$)	2310.92	Equipment dependent (See Appendix D)		--
3	Workforce number [Minimum/Maximum]	251/1722	16/89	444/1482	267/3204
4	Total periodic workforce cost ($\$/hour$) [Minimum/Maximum/Mean]	1250.30 /13713.50/ 8783.86	79.70/635.83/363.55	2453.59/10587.6/5280.68	1330/24301.1/4608.10
5	Total workforce cost (\$)	1.488×10^9	73.216×10^6		1.561×10^9
6	Annual workforce cost ($\$/Year$)	70.81×10^6	3.49×10^6		74.33×10^6
7	Total workforce (\$/TPA)	5.262	0.259		5.521
8	Total workforce [\$/MMBTU]	0.099	0.005		0.103

Expressing these values in terms of the firm's varying plant capacities reveals that on average, about 3 to 5 maintenance personnel may be adequate for regular hourly (PM and CM) maintenance intervention per MTPA of LNG, while TA maintenance may require a value that ranges between 25 and 66 $Man/MTPAhour$ (Table 4.16).

The combinatorial effect of these with the wage rate showed minimum, maximum and mean periodic intervention costs to be 79.70, 635.83 and 363.55 $/hour respectively for PM/CM and 2453.59, 10587.6 and 5280.68 $/hour respectively for TA maintenance (Table 4.16). The total cost for all modes of maintenance intervention was $\$73.22\times10^6$ or $0.26 per TPA of which about 77 and 23% constituted the total costs for PM/CM and TA maintenance respectively.

Thus, the workforce cost as a sum of production and maintenance operations workforce cost in terms of the total cost and cost per TPA were obtained as 1.56 billion dollars and 5.52 dollars per TPA (0.103 $/MMBTU) respectively.

4.8.4 Operational cost of liquefaction activities

As earlier mentioned (section 3.9.1), the OPEX for LNG liquefaction activities comprise those that take place in the plant towards converting feed gas to LNG. The cost includes all OPEX (cost of fuel gas usage, maintenance material utilisation, workforce remuneration and overhead cost) except resources expended on CAPEX, feed gas supply and LNG shipping activities. The results of the total OPEX for liquefaction activities within the study period are shown in Figure 4.21. A summary of the liquefaction OPEX results in terms of the annual and total expenditure as well as in terms of some KPIs is displayed in Table 4.17. Table 4.18 shows the results of the comparison of the LNGFWA's liquefaction OPEX KPIs with those of the case plants and industry.

For the LNGFWA, the liquefaction OPEX expended per hour was gotten as 164.39 $/hour at the minimum during regular liquefaction operations and 17.02×10^6 $/hour at the maximum (Figure 4.21) when maintenance inventory was ordered. From an annual perspective, the minimum and maximum expenses were 21.24×10^6 and 950.79×10^6 $/Year respectively.

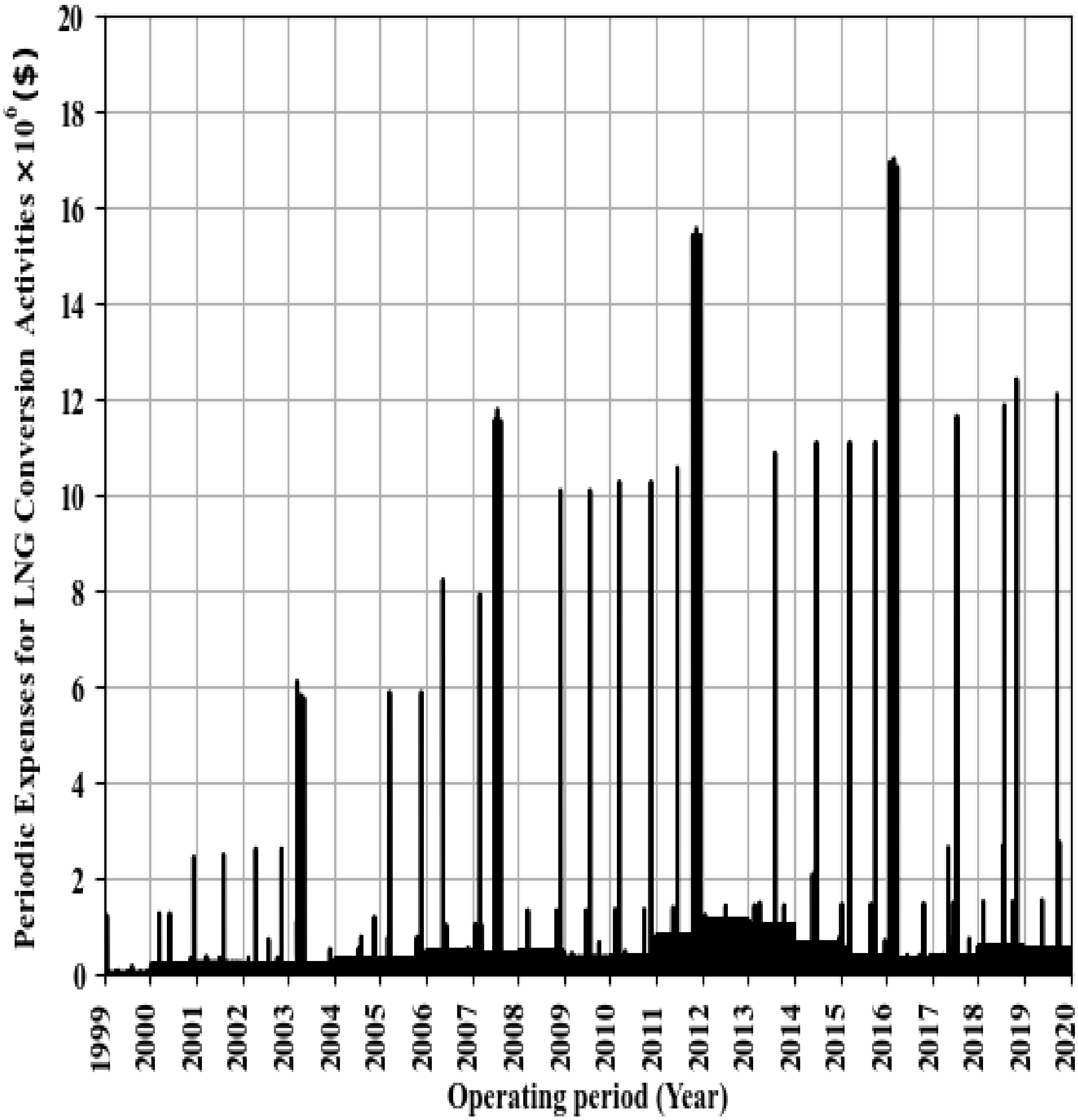

Figure 4.21: LNGFWA periodic liquefaction operating expenses

Table 4.17: Summary of the LNGFWA's OPEX (Less fuel, less shipping) for liquefaction operation based on Dollar of the project period

SN	Liquefaction OPEX Quantity	Liquefaction OPEX Constituent			Liquefaction OPEX
		Maintenance material management	Workforce	Overhead	
1	Periodic Expenses range ($\times 10^6$ \$/Year)	7.611-564.330	10.717-113.770	2.910-347.480	21.239-950.786
2	Average Periodic Expenses ($\times 10^6$ \$/Year)	163.100	74.319	124.662	362.081
3	Total OPEX ($\times 10^9$ \$)	3.428	1.561	2.618	7.607
4	Cost/Annual unit product volume (\$/TPA)	12.123	5.521	9.260	26.904
5	Cost/Unit energy liquefied (\$/MMBTU)	0.227	0.103	0.173	0.503
6	Average Fraction of annual contribution (%)	41.833	25.474	32.693	100
7	OPEX (% of CAPEX)	1.74	0.792	1.329	3.861
8	OPEX (% of feed gas cost)	10.38	4.727	7.929	23.036

Table 4.18: Comparison of the LNGFWA liquefaction OPEX (Less fuel) results with those of the compared plants and industry references

SN	Liquefaction OPEX Quantity		*Case Plant 1	*Case Plant 2	*Case Plant 3	*Case Plant 4	*Case Plant Average (Industry Reference)	LNGFWA
2	Average Periodic Expenses ($\times 10^6$ \$/Year)		611	385	251	248	373.75	380.75
4	Cost/Unit product volume (\$/TPA)		39.17	42.26	29.53	13.78	31.19	28.28
5	Cost/Unit energy liquefied (\$/MMBTU)		0.81	0.90	0.59	0.28	0.65	0.53
6	Average Fraction of annual OPEX contribution (%)	Maintenance material management	--	--	--	--	(57.14)	42.54
		Workforce	--	--	--	--	(11.90)	25.89
		Overhead	--	--	--	--	(30.95)	31.57
7	OPEX (% of CAPEX)		1.86	2.18	2.09	2.51	2.16	3.13
8	OPEX (% of feed gas cost)		27	29	19	13	22	24.13

***Source: (Songhurst, 2018)**

Over the study period, the expense incurred due to LNG conversion activities was 7.61 billion dollars. In terms of the cost per unit product volume and cost per unit energy produced, this amounted to 26.91 $/TPA and 0.503 $/MMBTU respectively (Table 4.17).

These values are equivalent to 28.28 $/TPA and 0.529 $/MMBTU when they are expressed in terms of the base evaluation period values.

A comparison of the base evaluation period results with similar results obtained for case plants 1-4, revealed that the liquefaction OPEX of the LNGFWA fell well within the range of those of compared organisations (13-43) $/TPA). Although these results appear acceptable, the much lower OPEX for a unit volume liquefied could be attained if the operational capacity of the plant is improved from its current 78.64% towards its design capacity.

Further, the investigation of the degree of contribution of the conversion OPEX constituents revealed that in order of decreasing contributions were equipment maintenance material usage (41.83%), overhead (32.69%%), workforce cost (25.47), this also is consistent with the industry index.

4.8.5 Shipping Cost

The total cost of shipping essentially comprises all costs incurred from all shipment delivery trips within the observation window and is an aggregate of the vessel charter rate, fuel cost, port rate estimates, canal transit tariffs and other related costs. Figure 4.22 shows the breakdown of the contributions of the LNG shipment delivery cost elements while the details regarding the shipment delivery costs at different periods within the study window are provided in Figure 4.23. A summarised breakdown of the firm's shipping cost is presented in Table 4.19 alongside the values of some related shipping cost driver items.

Based on the carrier capacities deployed (section 4.6.5.2), the number of LNG shipment delivery trips made annually by the LNGFWA as determined by the model was observed to vary between 3 and 320. This is equivalent to 1 and 14 shipments per MTPA of 11.67 Trips/MTPA average. These variations were attributed to the different design and operating capacities of the plant at different stages of the project, the carrier sizes and maximum loading capacity requirements as well as the product ready time.

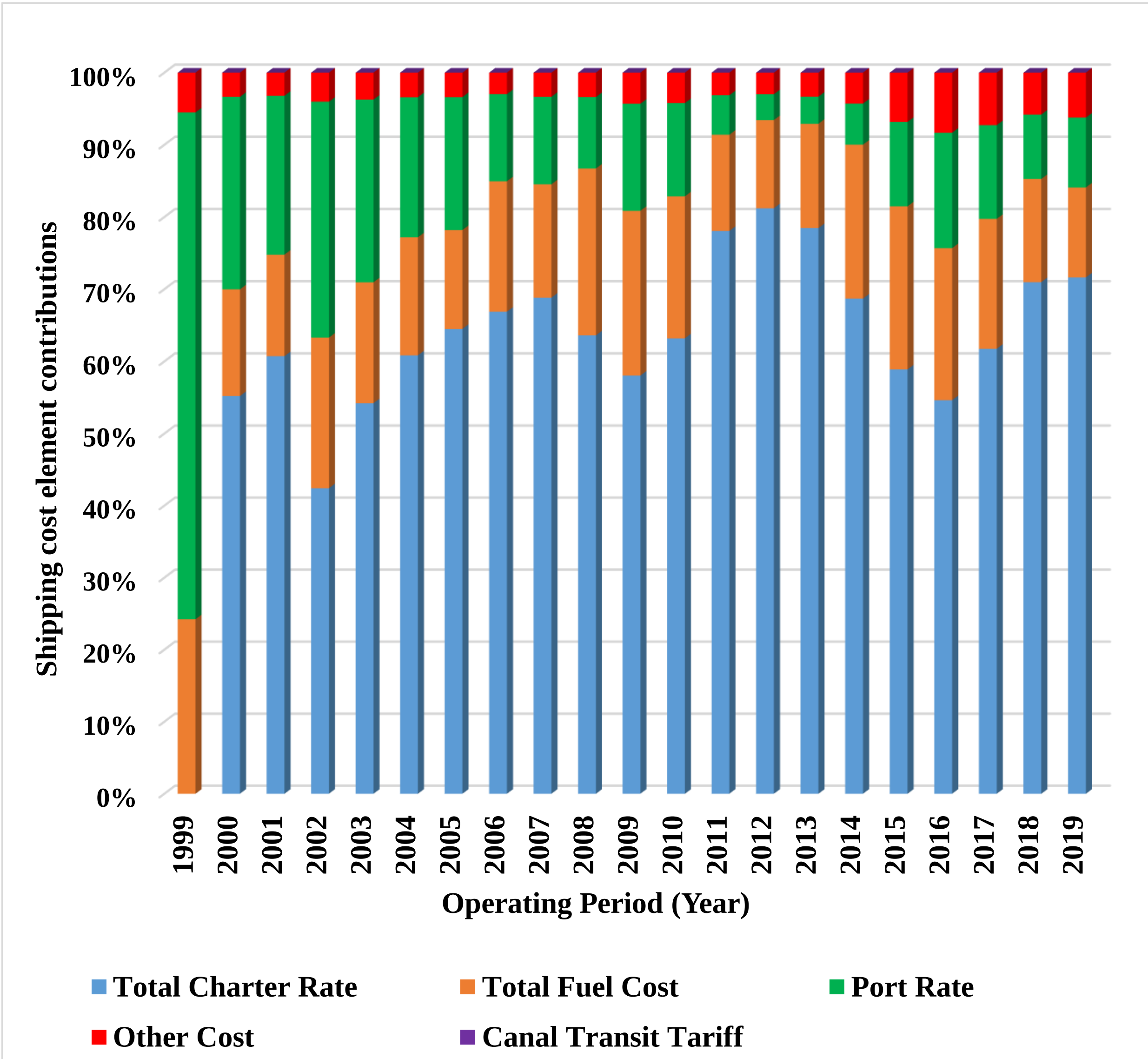

Figure 4.22: Percentage value of contributions of LNG shipment delivery cost elements

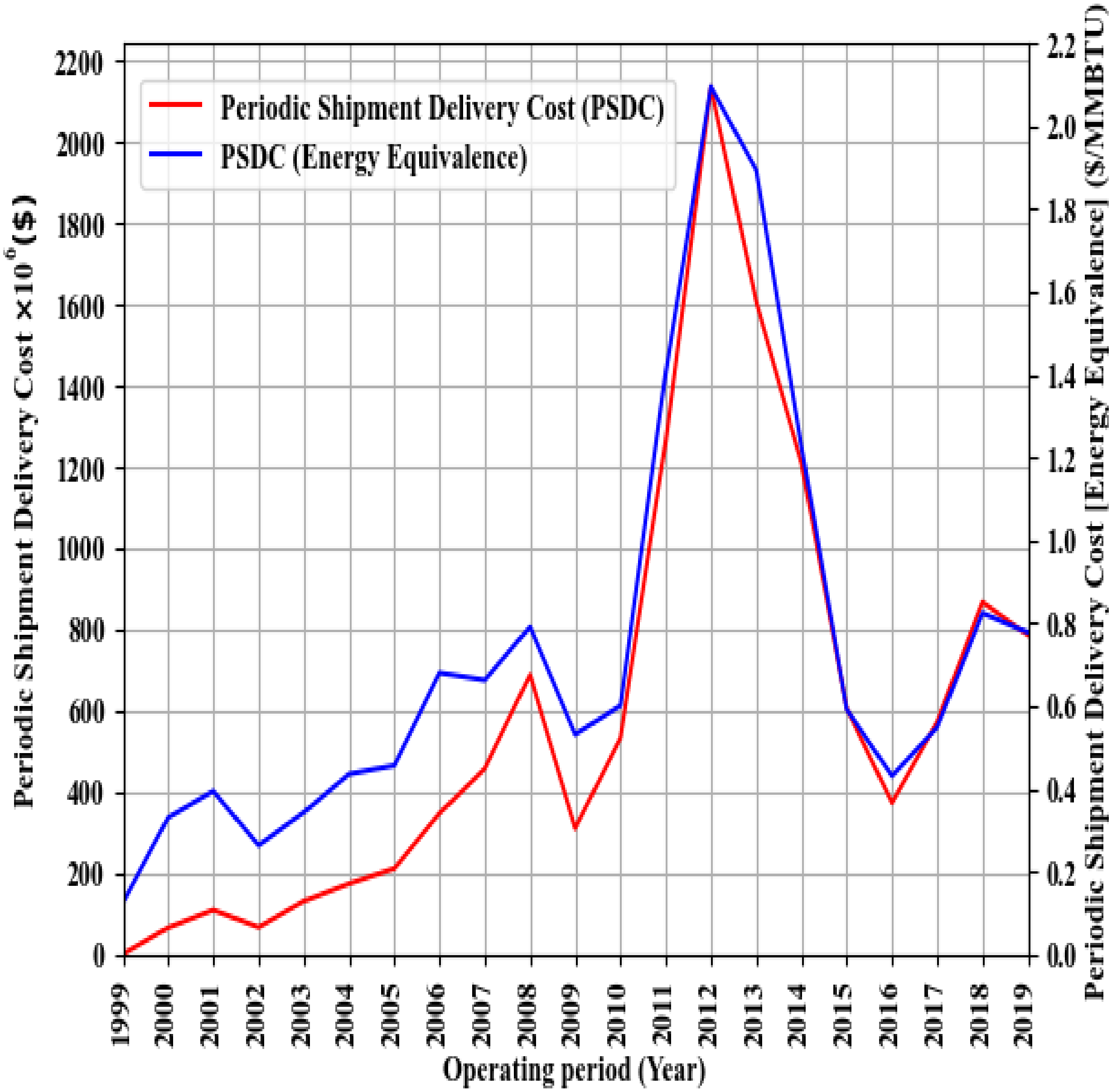

Figure 4.23: Annual shipment delivery cost and the corresponding energy equivalence

Table 4.19: LNGFWA Shipping cost breakdown with cost driver items

SN	Cost Related quantity	Value			
		Minimum	Maximum	Mean	Total
1	Charter Speed (Nautical Miles/hour)	--	--	15.84	--
2	Aggregated destination port distance with return (Nautical Miles)	4240.83/Year	9130.21/Year	6168.95/Year	129548
3	Number of LNG shipment deliveries	1/Year	320/Year	--	4385
		1/MTPA	14/MTPA	11.67/MTPA	
		9/ShipYear	1/ ShipYear	6/ ShipYear	
4	Number of shipping vessels deployed	1/Year	53/Year	--	53
5	Shipment Cost($)	1.20×10^{6}/Trip	7.35×10^{6} /Trip	3.41×10^{6} /Trip	12.53×10^{9}
		0.125/MMBTU	2.096/MMBTU	0.876/MMBTU	
		1.15×10^{6}/Year	2.14×10^{9}/Year	596.857×10^{6}/Year	

This amounted to a grand total of 4385 within the study window; a value that is 12.3% lower than the actual number of deliveries (5000) cited in literature sources (Nigerian Liquefied Natural Gas, 2020). It was further observed that about 69% of the deliveries were made by the 23 vessels that were either owned by the firm or under long-term charter contracts while the remaining deliveries appear to have been made from short-term contracted shipping vessels. Over the study period, the cost per delivery (laden and ballast) journey was observed to vary between 1.20 and 7.35 million dollars with an average delivery cost of $\$3.41\times10^6$ per trip (Table 4.19).

In addition, the investigation of the impact of the shipping cost contributors revealed that the fractions of the shipping cost contributors generally varied from one period to another (Figure 4.22) due to factors related to the source-destination port distances, port charges and the frequency in which the deliveries were made, the varying cost of fuel oils and fuel BOGs, the varying insurance and brokerage fees as well as the savings made by the firm from non-payment of vessel charter fees due to its direct ownership vessels.

For instance, in situations where the vessels used are owned by the firm, the vessel charter cost contribution was zero (Figure 4.22), while cost contributions from fuel usage and port charges were observed to be as high as 73 and 70% respectively. However, when vessel charter fees were made in fulfilment of charter agreements, those fees were observed to constitute the highest contributors with values as high as 83% of the cost of delivery per trip. On average, the percentage contributing fractions for the vessel charter cost, fuel cost, port charges and other costs were obtained as 56.47, 22.83, 15.21 and 5.49% respectively. This result showed that vessel charter cost was the most influential product delivery cost contributor, followed by fuel costs while charges such as insurance and ship brokerage fees (other costs) were the least cost contributors. Canal tariffs were assumed to be non-existent as it appeared that the sea routes for the firm's charter did not involve passing through the Panama or Suez canals.

Given the varying carrier sizes utilised in these deliveries and the constraint placed on their maximum shipment capacities, the cost of energy delivery to the destination port by the varying carrier sizes utilised was observed to be as low as 0.125 \$/MMBTU and as high as 2.096 \$/MMBTU (Figure 4.23). The case of the former occurred when the vessel charter cost contribution was zero and the number of days spent on route to the destination port was small (24.58 days). In the case of the latter, the vessel charter cost contribution obtained from a high daily charter rate ($121171/day) was about 80% (Figure 4.13) and the number of days of cargo shipment was also high (44.25 days). The average energy delivery cost was 0.882 $/MMBTU.

The results of these interactions caused the total expenses made on shipping from an annual perspective to range between 1.15 million dollars and 2.14 billion dollars per annum (Figure 4.23). Thus, the total cost of LNG shipping and delivery by the LNGFWA over the twenty-one-year period of analysis amounted to 12.53 billion dollars.

4.9 System life cycle cost and economic performance of case study

The results of the life cycle analysis and economic performance of the organisation based on the output of the SD-LNG-LCC model are here discussed. These include the items namely the total life cycle cost (TLCC) of the project, the unit production cost and the economic performance outcomes of the LNG production project.

4.9.1 Total life cycle cost and cost driver contributions

The total life cycle cost (TLCC) of the LNGFWA LNG production project is the aggregated values of all the contributions of the midstream and downstream LNG production cost-driving elements discussed individually in section 4.9. At the end of the twenty-one-year (1999-2019) study window, the TLCC amounted to 62.50 billion dollars. The TLCC accumulation and its drivers are shown in Figure 4.24. Figure 4.25 and Figure 4.26 display the contributions of the TLCC driver elements while Table 4.20 provides a summary of the TLCC of the organisation.

From Figure 4.24, it can be observed that in order of the increasing cost, the TLCC contributing elements were the cost of workforce remuneration and welfare ($\$1.56 \times 10^9$), overheads ($\$2.62 \times 10^9$), equipment maintenance materials ($\$3.43 \times 10^9$), depreciation ($\$9.38 \times 10^9$), shipping ($\$12.53 \times 10^9$) and feed gas supply ($\$33.01 \times 10^9$).

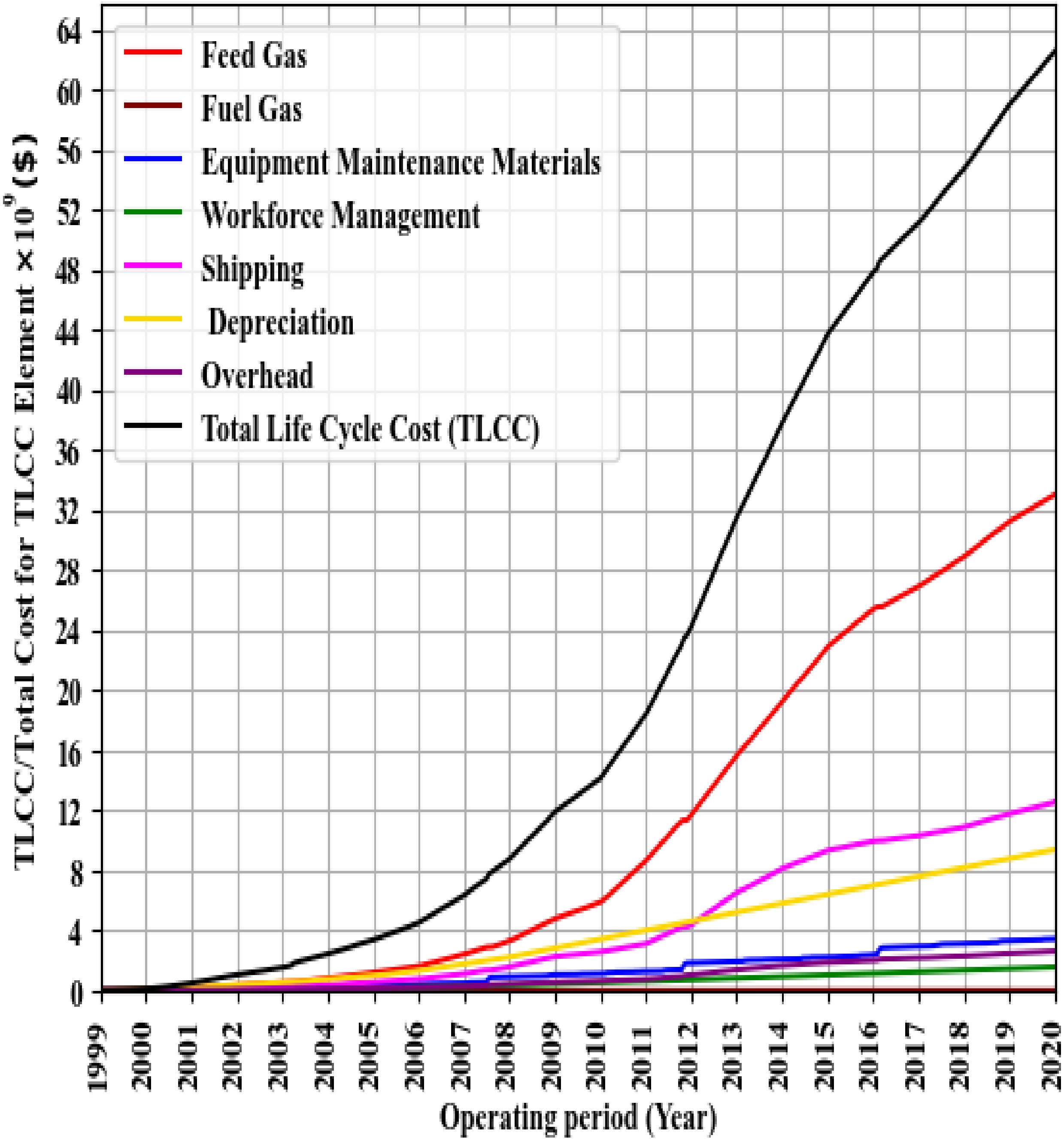

Figure 4.24: Total life cycle cost and Total cost of contributing elements

Figure 4.25: LNGFWA LNG project cost elements percentage contributions to the TLCC

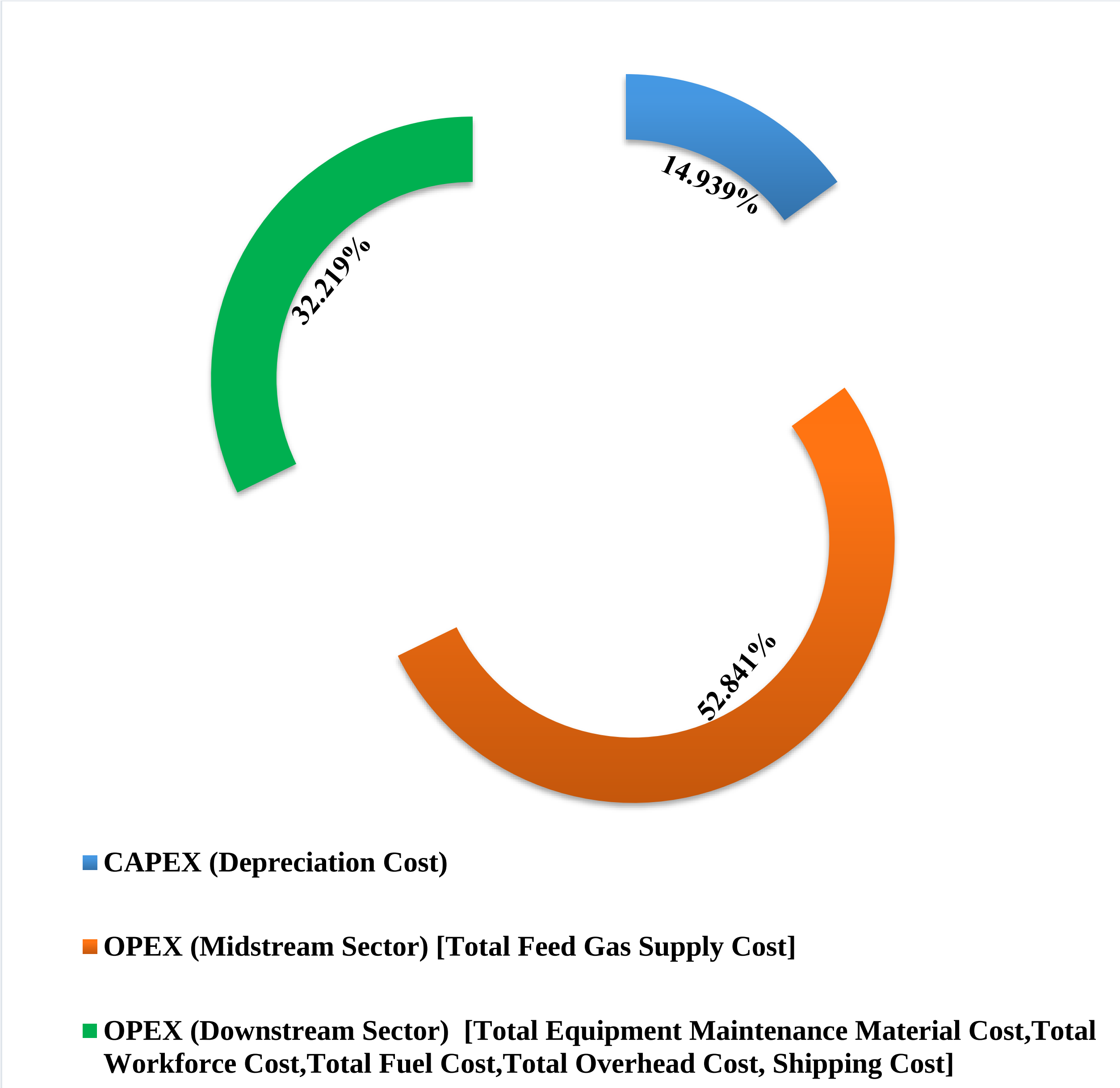

Figure 4.26: LNGFWA LNG project sector percentage cost contributions to the TLCC

Table 4.20: Details and breakdown of the total life cycle cost of the LNGFWA

	LNG production activity sector	TLCC Quantity	TLCC Quantity Contribution					LNG production sector contribution (%)
			Total $\times 10^9$ (\$)	Annual $\times 10^6$ (\$/Year)	S/TPA	\$/ MMBTU	%	
1	Pre-LNG Production	CAPEX (Depreciation)	9.338	444.673	--		14.939	14.939
2	Midstream	Feed gas supply	33.030	1572.033	116.792	1.187	52.841	52.841
3		Fuel gas supply	--	--	--	--	--	
4	Downstream (Liquefaction)	Equipment material and spares	3.428	163.100	12.123	0.227	5.484	32.219
5		Workforce	1.561	74.319	5.521	0.103	2.497	
6		Overhead	2.618	124.662	9.260	0.173	4.188	
7	Downstream (Shipping)	Shipping	12.533	596.857	*46.810	**0.876	20.050	
			62.508	2975.644	--	--	99.999	

***Dollar per unit volume shipped; ** Dollar per unit energy content shipped**

In terms of their total percentage contributions to the TLCC, these cost element values correspond to 2.50, 4.19, 5.48, 14.94, 20.05 and 52.84% respectively (Figure 4.25). It can be inferred from the results obtained (Table 4.20) that the midstream OPEX (feed gas supply cost [52.84%]) contributed the most monetarily to the LNG TLCC of the firm, followed by the downstream OPEX (liquefaction and shipping activities [32.22%]), while CAPEX (depreciation cost [14.94%]) was observed to provide the least contribution (Figure 4.26).

It is clear from the results obtained that the CAPEX and feed gas expenses and shipping expenses exert the most significant influences on the TLCC as it makes up a total of more than 85% percentage of the plant's TLCC. This insight brings to the fore the potential of TLCC reduction through investigations into initial capital investment reduction, cheaper feed gas supply and LNG delivery strategies.

4.9.2 Unit production cost

The unit LNG production cost for the organisation under study was observed to be $80.21 $/MMBTU in the early hours of the flag-off of LNG production operations (Figure 4.27). This value quickly dropped to a value below 11 $/MMBTU at the end of the first year of operation and hovered between 2.0 and 4.5 $/MMBTU in subsequent years. The mean unit cost of production within the observation window was 3.56 $/MMBTU. In addition, a comparison of the periodic cost of LNG production and the firm's product sale prices (Figure 4.28), revealed that the former quantity was generally lower than the latter between 2001 and 2019. This indicates that the business is self-sustaining and profitable. It is also observable from Figure 4.28, that the unit LNG production cost was slightly unstable as its value gradually increased within the study period. This behaviour can be attributed on the one hand to increases in OPEX costs caused by inflationary effects and the change in feed gas pricing policy which appears to have been reviewed upwards from 2009.

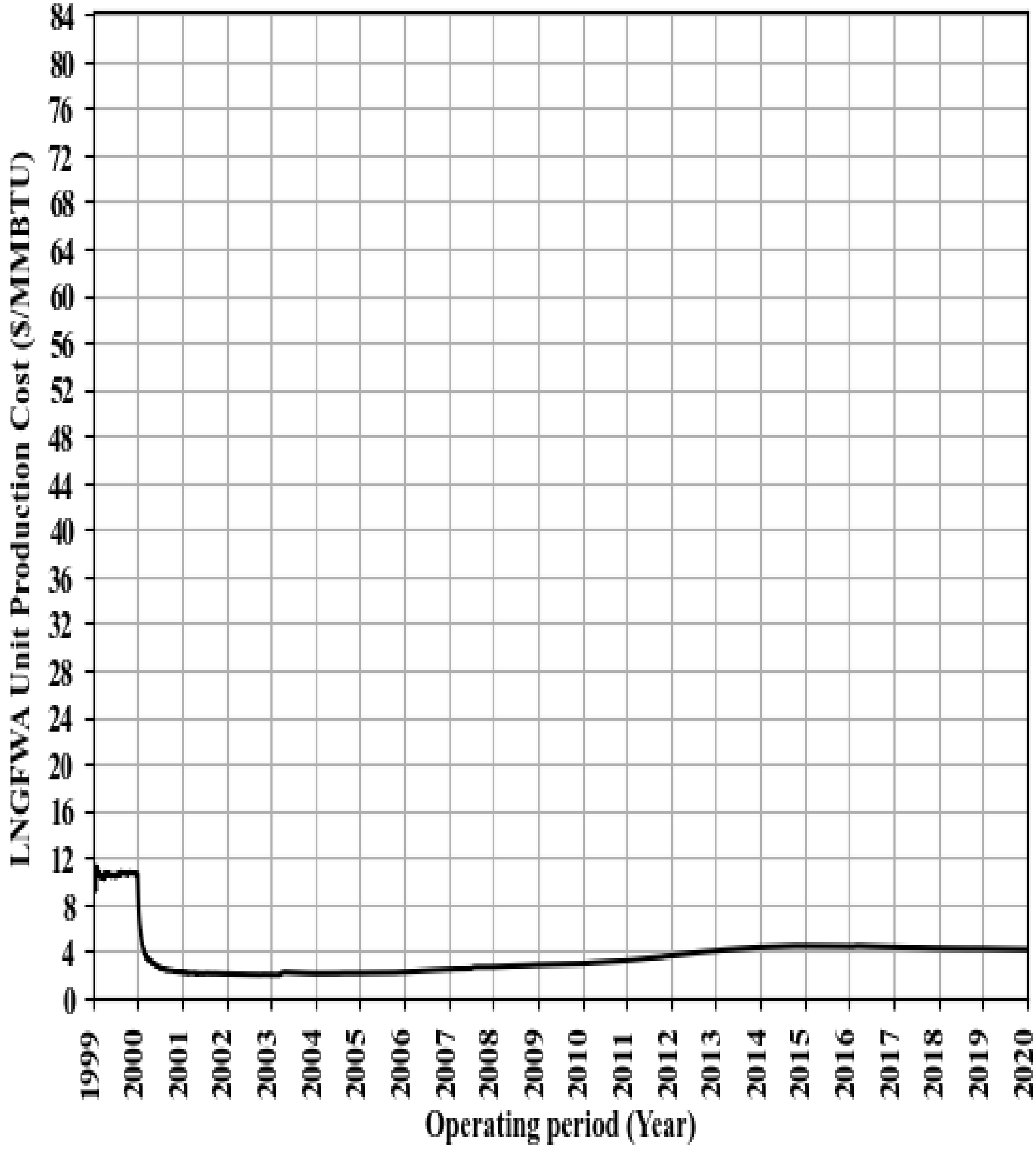

Figure 4.27: Profile of the periodic unit LNG production cost of the LNGFWA

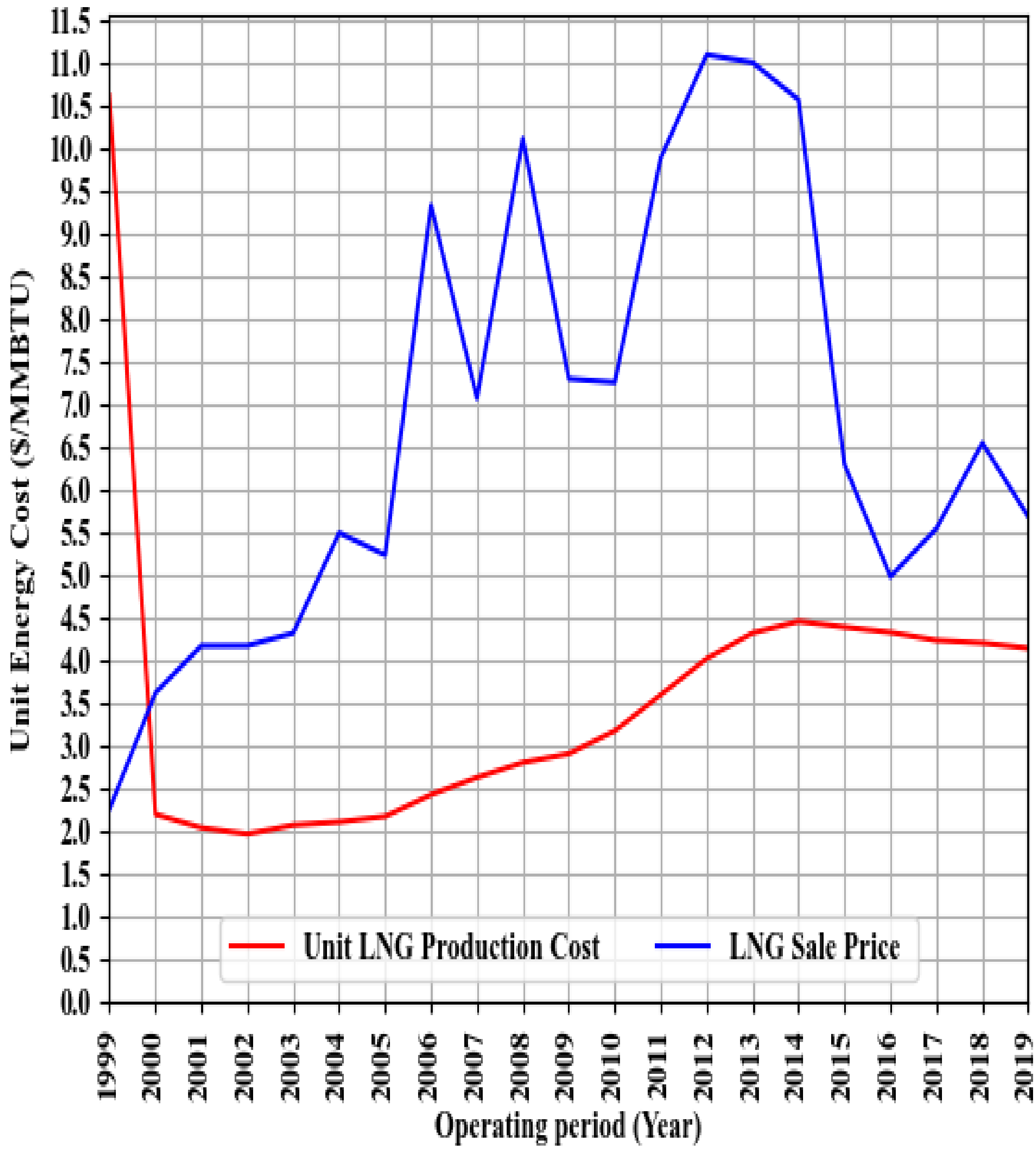

Figure 4.28: LNGFWA periodic unit production cost in comparison to the LNG sales price

4.9.3 Economic performance of the LNG production organisation

The economic performance of the LNG production firm based on the strategy deployed by the firm over the studied period indicated that the firm's earnings before interest and tax (EBIT) was 51.00 billion dollars. In addition, the breakeven point (BEP) of the venture was determined to be 7.34 years (approximately 7 years and 4 months) [Figure 4.29] at a BEP quantity of 90.61×10^6 $m^3 LNG$ (40.78 MT). Based on the total non-BOG LNG shipped by the end of 2020 (594.90×10^6 $m^3 LNG$ [267.73 MT]), this implies that 84.77% of LNG shipped (80.27% of LNG produced) was sold for profit. These results indicate an impressively profitable venture. Also, the annual return on investment (ROI) was observed to fluctuate between -5.41 and 64.90% for each production year with a negative ROI recorded in 1990 and positive ROIs in subsequent years (Figure 4.30).

This is expected due on the one hand to the different capital investments injected at different periods of the project for Greenfield and brownfield expansion. On the other hand, the annual ROI is affected by the varying product sale price and the plant's operating capacity at different periods.

Considering the study window, the ROI for the total EBIT over this period was obtained as 26.01% (Table 4.21). This shows that with about a 26% margin on the investment cost, the project is both efficient and profitable. In addition, the investigation of the viability of the project using time-value-of-money based indicators at the 12% discount rate adopted in the study, a positive NPV of $\$14.81\times10^9$ was obtained.

When this value was compared with the CAPEX, it resulted in a profitability index (PI) of 1.59. Further, the internal rate of return of the project was determined to be 31.70% (Table 4.21). These results further validate the project as being economically viable with good investment potential.

4.10 Scenario analysis

The results and discussion of the comparison of the current state of performance of the LNGFWA project with simulated scenarios *vis-a-vis* some changes in the values of some of the model's input quantities are presented and discussed in this section.

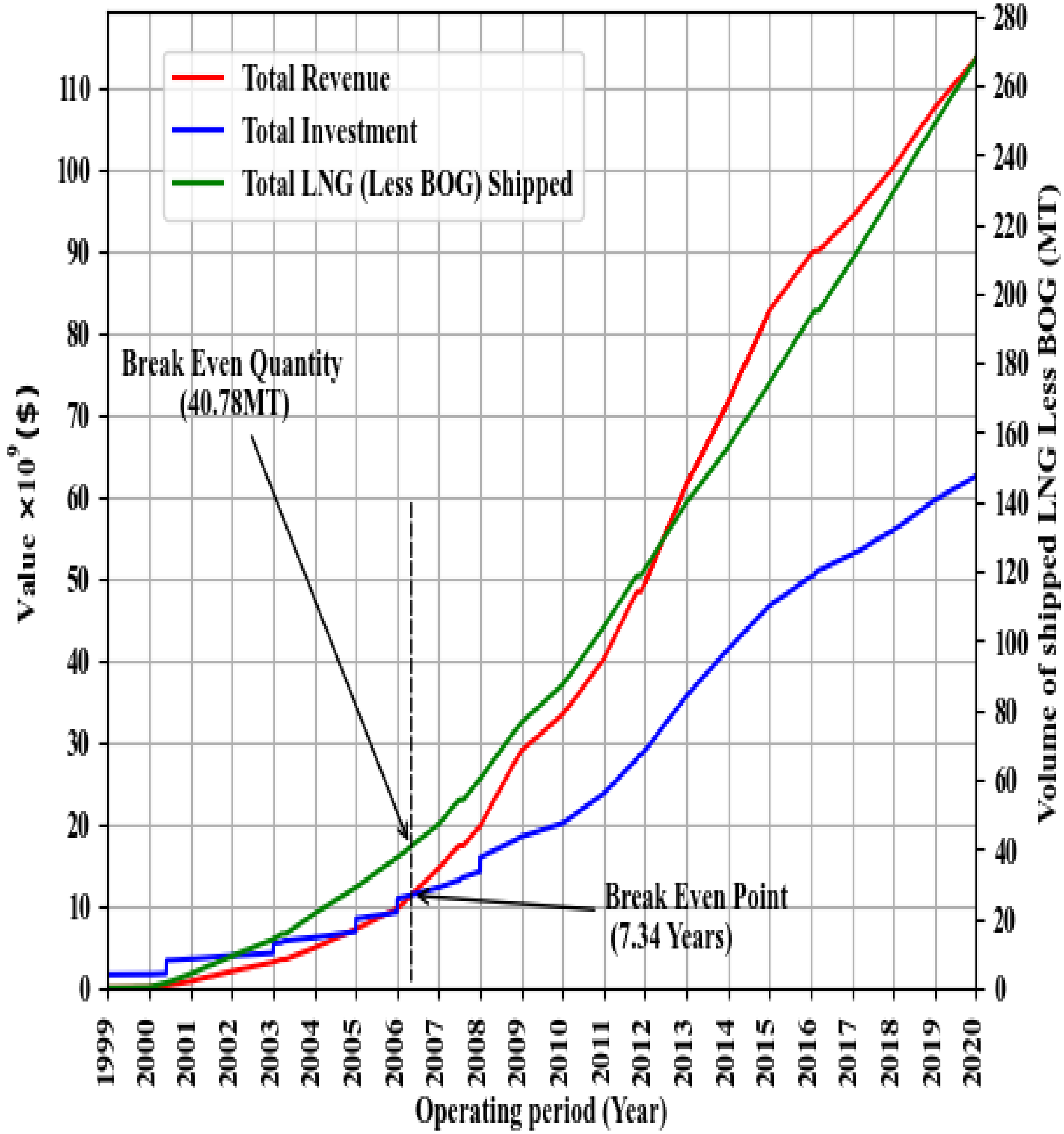

Figure 4.29: Trend profile of the Total investment, total revenue and total LNG volume (less BOG) shipped showing the breakeven point (BEP) and break-even quantity

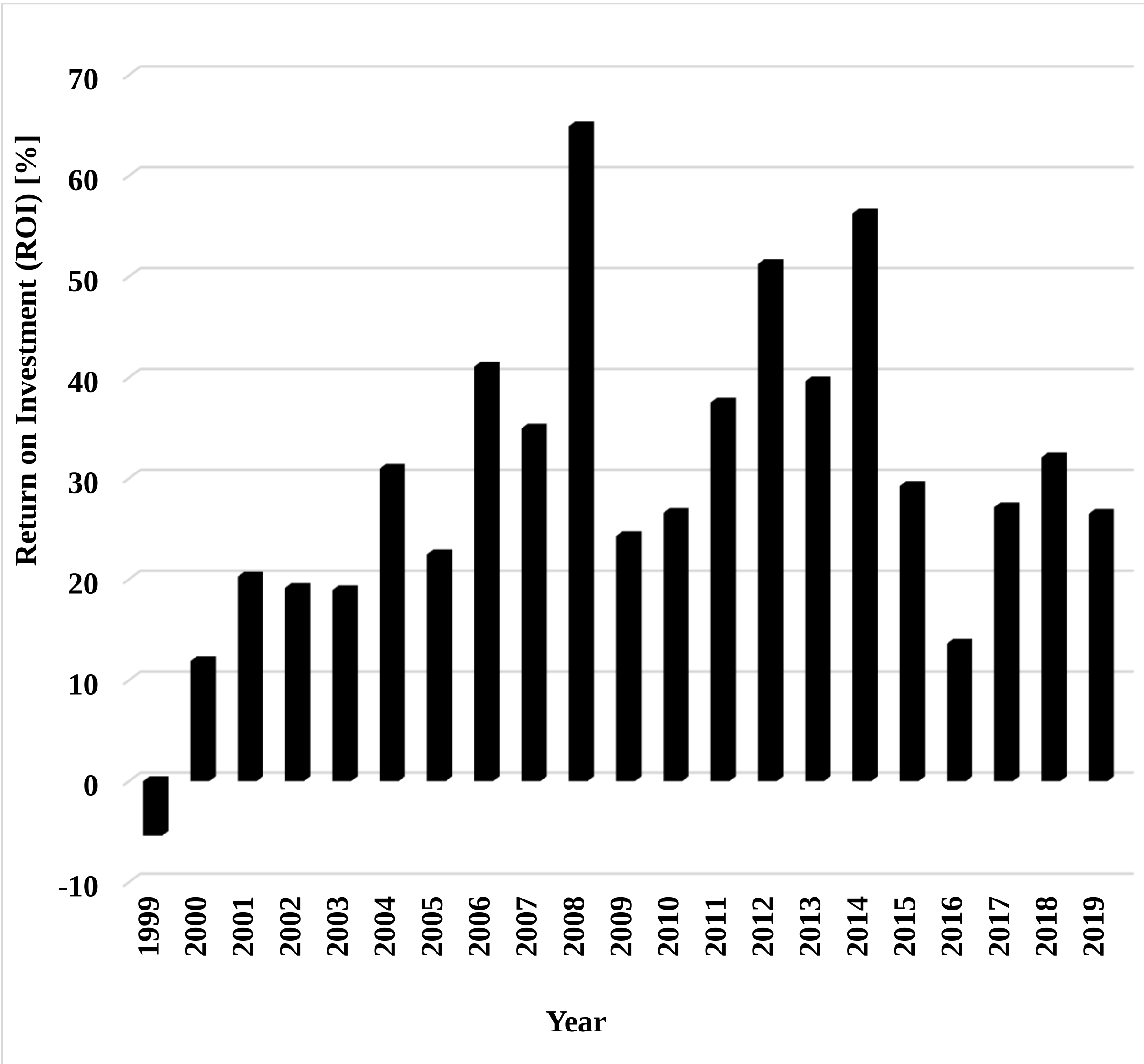

Figure 4.30: Annual percentage return on investment for the LNGFWA

Table 4.21: Economic performance values for the LNG project of the case study

SN	Input /Investment		Economic performance	
	Quantity	**Value**	**Quantity**	**Value**
1	Initial investment (CAPEX) ×[$\$\times10^9$]	9.338	--	--
2	Discount Rate (%)	12	--	--
3	--	--	Profit (EBIT) ×[$\$\times10^9$]	50.997
4	--	--	Break-Even Point (BEP) [Years]	7.34
5	--	--	Return on Investment (ROI) [%]	26.006
6	--	--	Net Present Value (NPV) ×[$\$\times10^9$]	14.81
7	--	--	Profitability Index	1.586
8	--	--	Internal Rate of Return (IRR) [%]	31.696

Specifically, the results of the experiments undertaken on the SD-LCC-LNG model to determine the LNGFWA system responses to changes in some of the model's input listed in Table 3.8.

4.10.1 The economy of Greenfield projects versus Brownfield Projects

The Greenfield project equivalent scenario (GPES) of the firm's current design capacity (i.e. 22.2 MTPA from time zero) produced a TLCC value of $\$73.73 \times 10^9$ compared to $\$62.50 \times 10^9$ of the current scenario (CurS). This outcome is expected given that cost benefits experienced by the firm regarding the different brownfield expansions undertaken in the project life are non-existent in the GPES. The unit production cost of the GPES (3.55 $/MMBTU) was however observed to be lower than that of the CurS (4.14 $/MMBTU). Figure 4.31 shows the unit production cost profiles of the compared scenarios.

Based on the observation that the plant design and operation capacities of the GPES are larger than that of the CurS for most parts of the study window (Figure 4.32), this result is expected. From the model's outputs, it can be said that setting up expected plant design capacities from Greenfield rather than adopting incremental Brownfield expansion policies will most likely lead to relatively higher production volume (GPES: 388.69 MT; CurS: 282.77 MT) and eventually shorter payback periods (GPES: 6.69 years; CurS: 7.34 years).

Thus, amid similar LNG production cost factors, the production cost per unit product will be lower for Greenfield projects than those involving Brownfield expansions leading to a similar trend in revenue (GPES: $\$140.59 \times 10^9$; CurS: $\$113.50 \times 10^9$) and the ROI (GPES: 29.82%; CurS: 26.01%) of the comparison. However, the NPV of CurS ($\$14.81 \times 10^9$) was higher than ($\$14.10 \times 10^9$) of the GPES. It was also observed that in terms of the IRR and PI, the CurS value (31.70 %, 1.59) was higher than those observed for the GPES (24.68%, 1.32).

These results clearly show in terms of the time value of money influenced economic performance indicators that multiple Brownfield expansion projects over time are more profitable than Greenfield projects of equivalent total design and operational capacities. The impact of these in the context of investor decisions is that greater monetary value is attained from the production of less volume of LNG products.

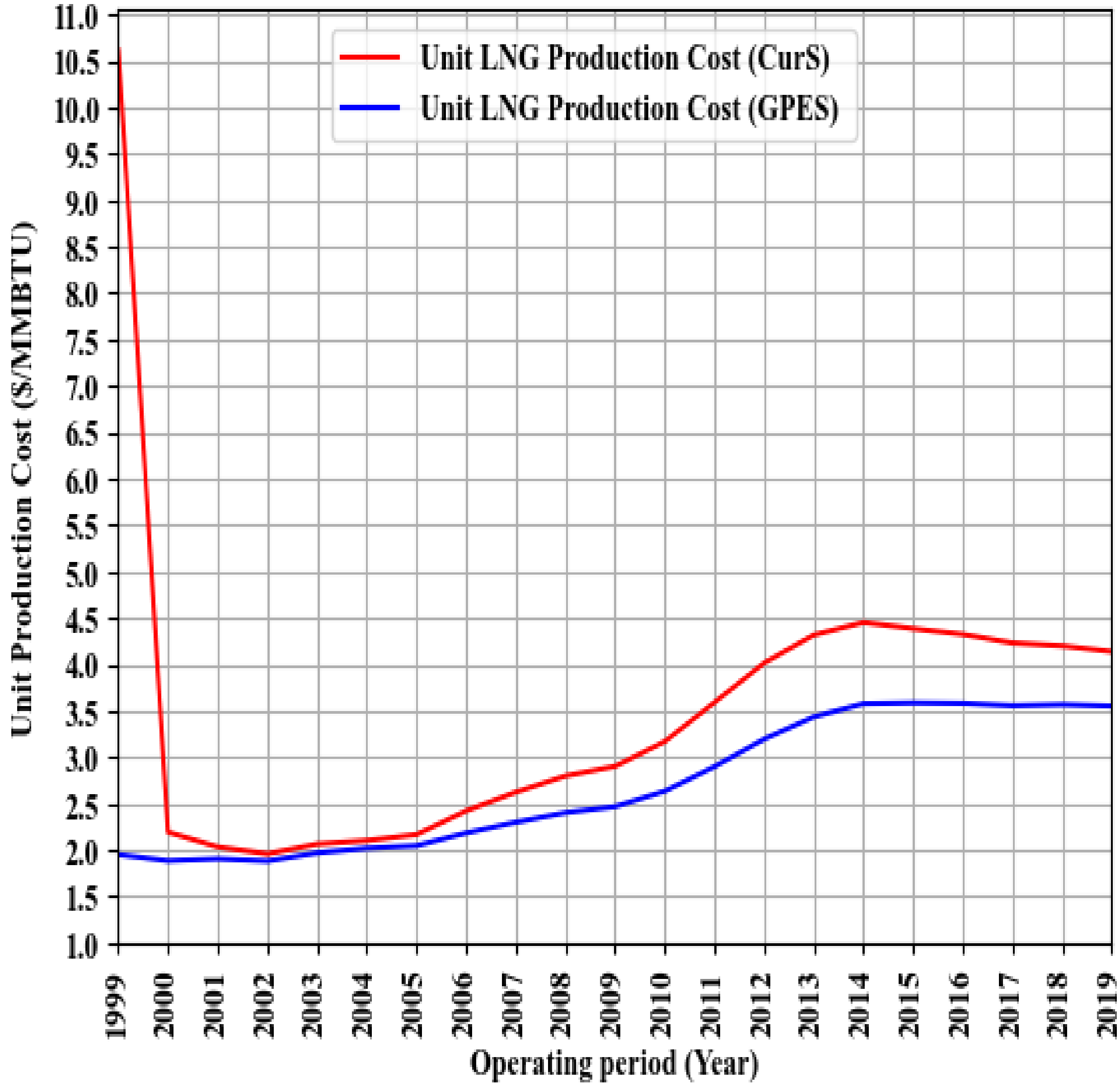

Figure 4.31: Unit cost profiles of the current LNG production project compared to the Greenfield project equivalent

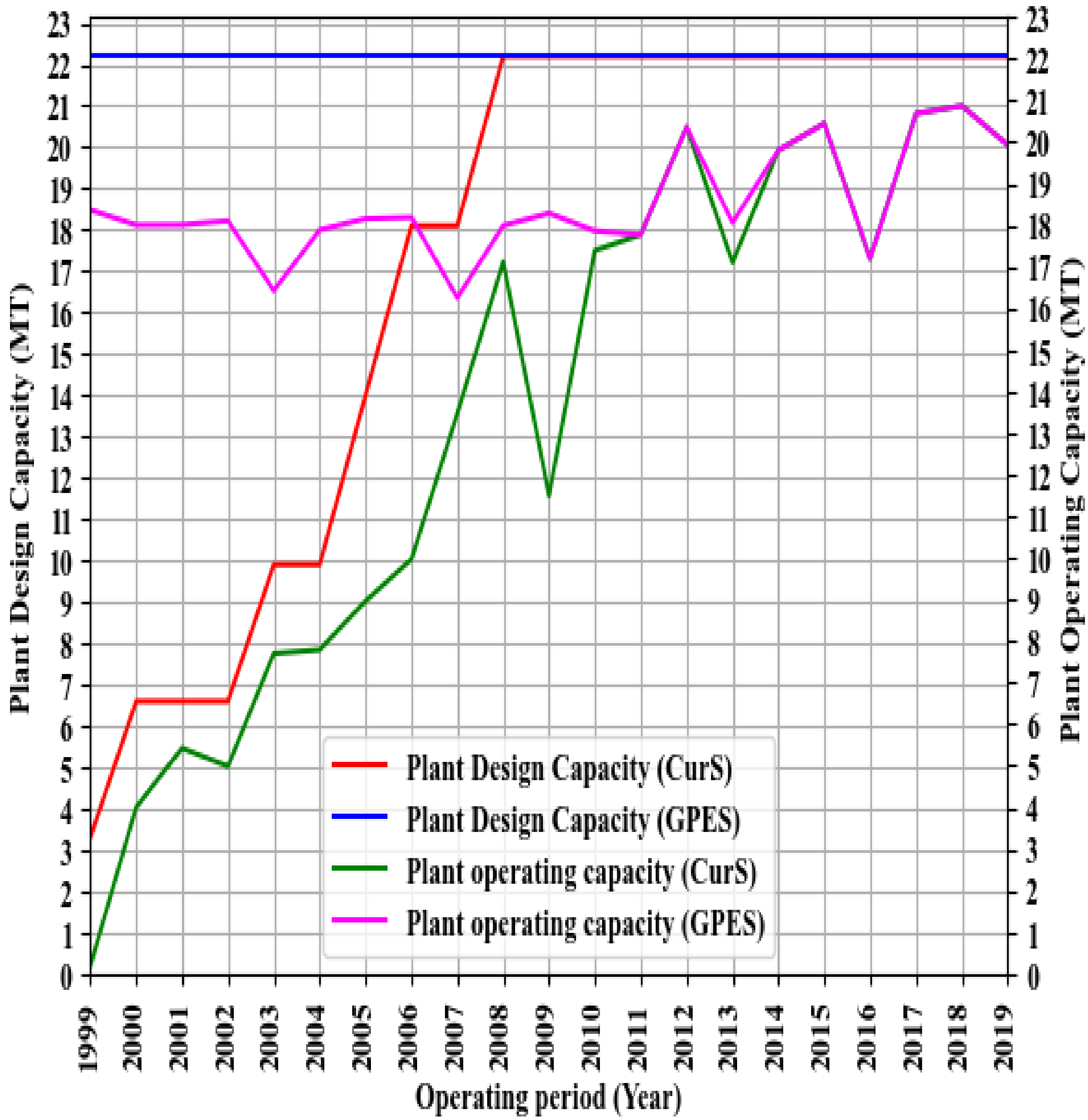

Figure 4.32: Compared plant design capacities and operating capacities of the current production scenario and the Greenfield project equivalent scenario

Furthermore, the NPV and PI results for the two scenarios reveal that although the NPV values are somewhat equal, there is a marked difference in the PI caused by the difference in the CAPEX values of the compared scenarios (GPES: \$10.68 $\times 10^9$; CurS: \$9.34 $\times 10^9$). Thus, it appears more viable to start up with LNG Greenfield projects of small capacities and gradually build up in increments of Brownfield expansions.

4.10.2 Effect of Train Capacities

The sensitivity of the model to the different train capacity scenarios ($TrCap_x$: $x =$ 3, 5, 10, 20, 30 MTPA) under the operating conditions of the firm within the study window showed as expected, that the TLCC varies in direct relation with the plant design and operating capacities of the different scenarios. However, it was observed that generally, the unit production cost gradually increased as the plant capacities increased.

This behaviour was further observed in the ROI, NPV, PI and IRR of the scenarios. As an example, the PI of $TrCap_3$ and $TrCap_{10}$ were about 149% and 133% respectively, while $TrCap_{30}$ was 125.92%, while the IRR was 25.96, 24.89 and 24.46 %, respectively (Figure 4.33). A similar observation regarding this behaviour was made by (Da Silva Sequeira, 2019). The obtained results imply that it is more profitable to invest in and operate smaller LNG production plants than large-sized plants.

4.10.3 Model sensitivity to changes in LNG feedstock price

It was observed that the TLCC of the LNG varies in the feed gas stock price (FGSP). Figure 4.34 shows that increases in the FGSPs caused corresponding TLCC increases for all scenarios considered. This outcome is expected because by implication, increases in FGSPs will impact and cause increases in corresponding feed and fuel gas expenses, thus adding to the overall LCC of the plant.

There was no observed impact of FGSP changes on revenue. This implied that LNG profit reduction was observed when FGSPs increased and vice-versa. In terms of profitability performance, it was observed that the PI of the project was higher for lower feedstock prices and *vice versa*. For example, a PI of 2.47 was observed for a feedstock price of $0.25C_{LNG}^{Gas}$ and 0.69 for $1.75C_{LNG}^{Gas}$ (Figure 4.34).

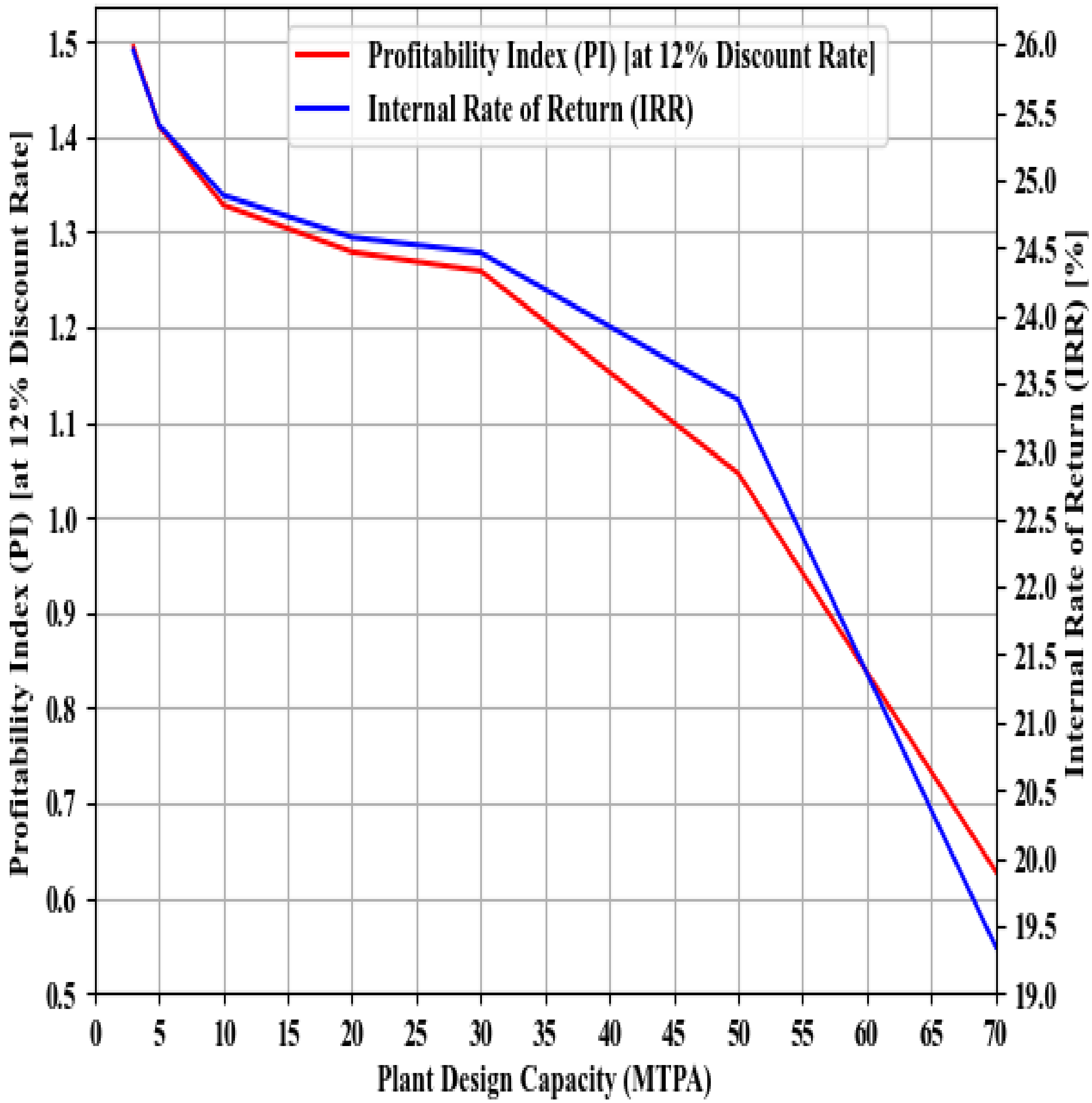

Figure 4.33: Profitability index and Internal rates of return for different LNG plant design capacities

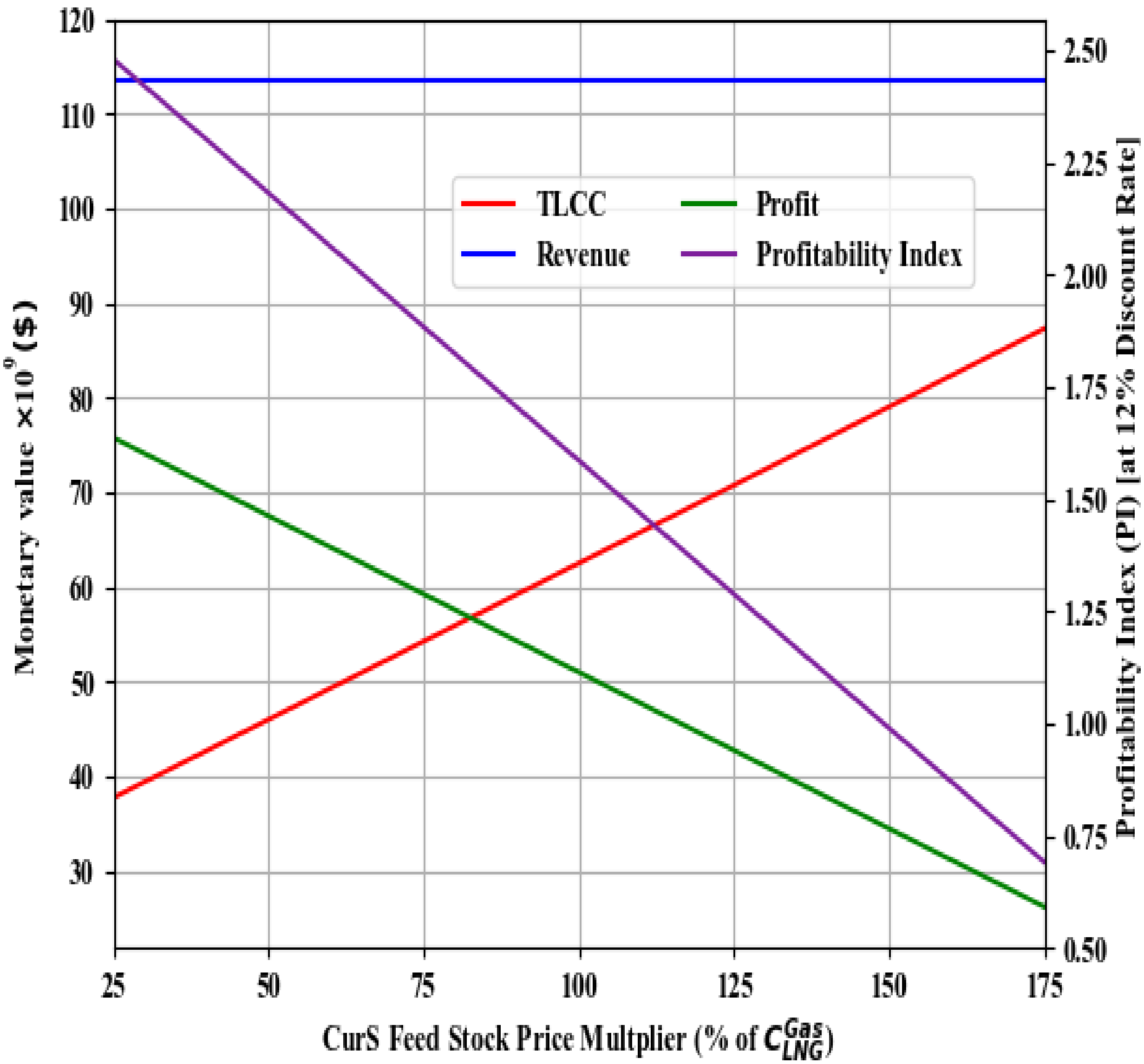

Figure 4.34: Effect of change of the feedstock price $\left(C_{LNG}^{Gas}\right)$ of the current production scenario (CurS) on the total life cycle cost, revenue, profit and profitability index

4.10.4 Plant Productivity

The investigation of different scenarios of the current LNGFWA plant productivity ($K^{PrC} = 9753$) revealed that lower plant productivity leads to the incurring of lower TLCC and *vice versa* (Figure 4.35). In the case of lowered TLCC, this was understood to occur as fewer resources needed for LNG production are utilised due to lowered productivity while the reverse is the case for higher TLCCs. Productivity changes affecting the TLCC occurred via corresponding changes in expenses at all LNG production sub-sectors (Feed gas supply, maintenance shipping and overhead) except the labour sector (Figure 4.35). This is expected as the number of human resources required for the project execution remained unchanged.

It was also observed that at the discount rate considered, the levels of plant productivity lower than $0.5968K^{PrC}$ produced negative NPVs implying the non-profitability of investments (Figure 4.36). In addition, the PI at $1.10.5968K^{PrC}$ (100% plant productivity) was obtained as 1.69, a value which is about 6% more than the PI observed at the current plant's productivity value ($K^{PrC} = 97.53\%$). These results underscore the need to ensure desired productivity by maintaining the right processes, equipment, human resources and adequate motivation.

4.10.5 Maintenance Effectiveness

It was observed that reductions in maintenance effectiveness $\left(f_{Mtce}^{Eff}\right)$ led to increases in total expenses that are linked to equipment maintenance (E_{xMtce}) and overhead (E_{xOH}). For example, when the maintenance subsystem performance was observed at $f_{Mtce}^{Eff} = 10\%$, E_{xMtce} (\$11.36 ×10^9) was more than three times that expended when f_{Mtce}^{Eff} was 90% (E_{xMtce} =\$3.44 ×10^9) (Figure 4.37A). In the case of E_{xOH} for the same scenario, the values were \$2.87 ×10^9 and \$2.62 ×10^9 respectively (Figure 4.37B).

It was made clear from the results that when the maintenance on equipment was not effective enough, it lead to increased maintenance material usage costs. In addition, it could potentially lead to OH costs due to increased maintenance actions as well as increased orders for equipment spares and maintenance materials.

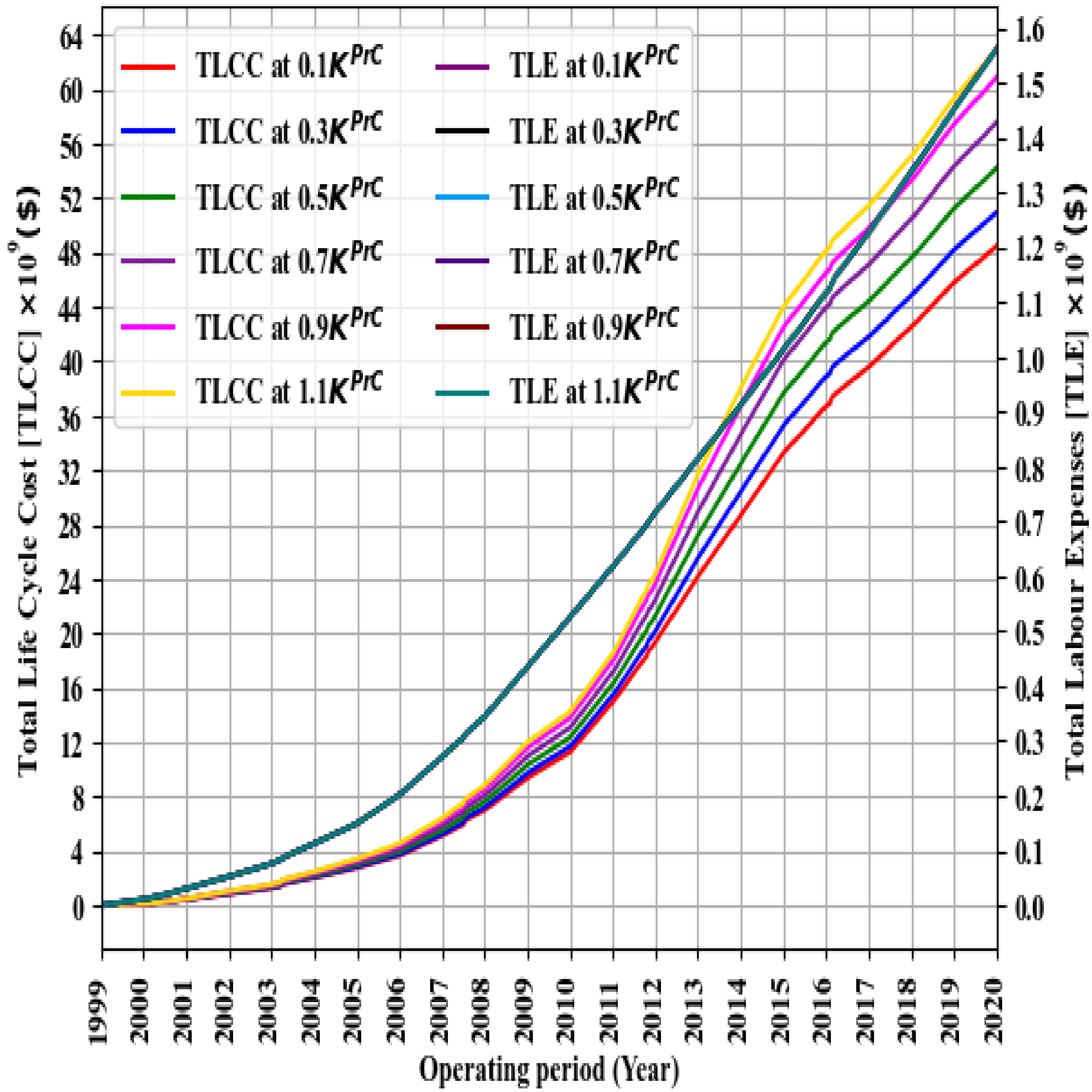

Figure 4.35: Total life cost and total labour expenses at different scenarios of the LNGFWA current plant productivity (K^{PrC}) value

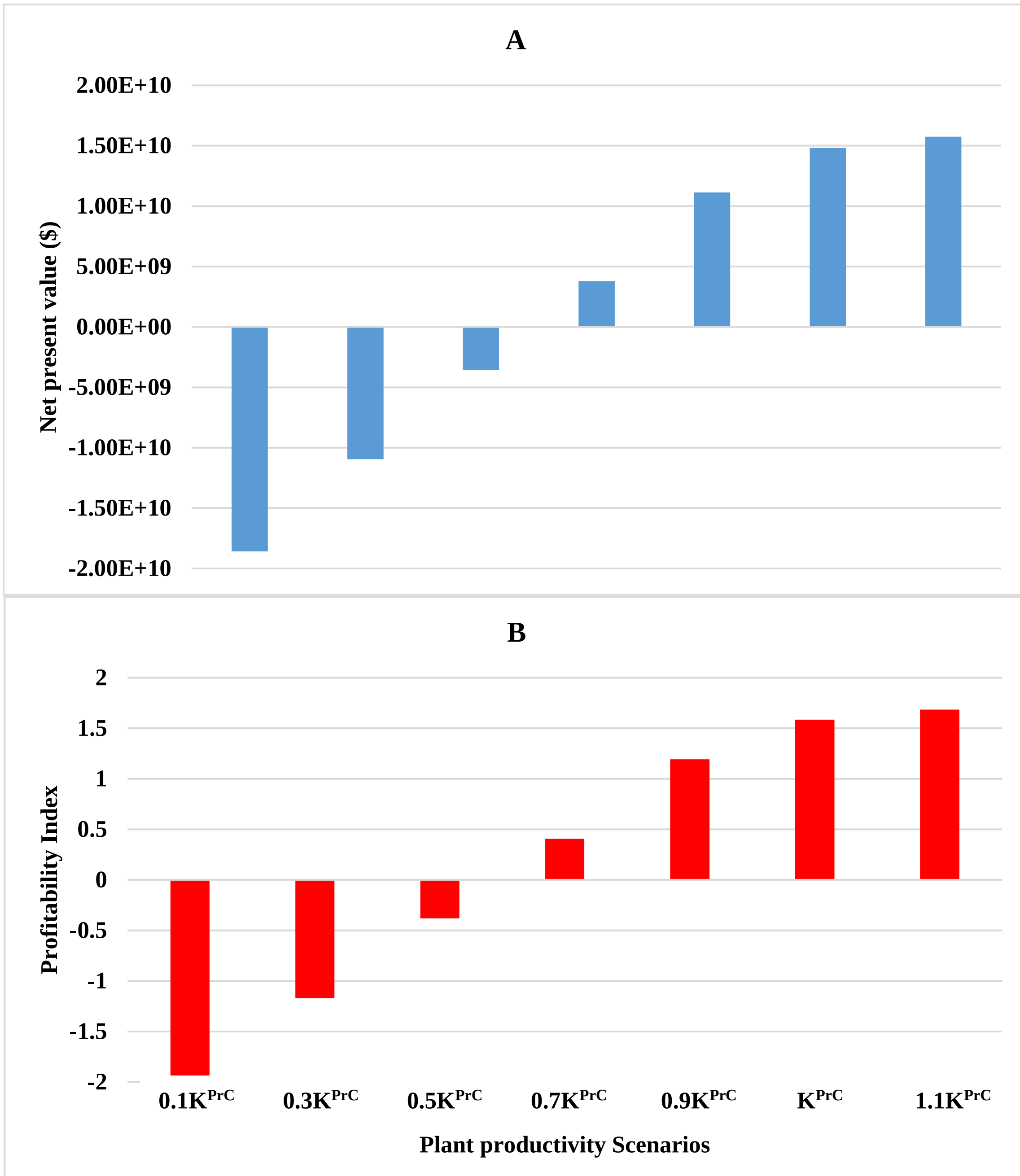

Figure 4.36: Net present values and profitability index values for corresponding plant productivity (xK^{PrC}) scenarios

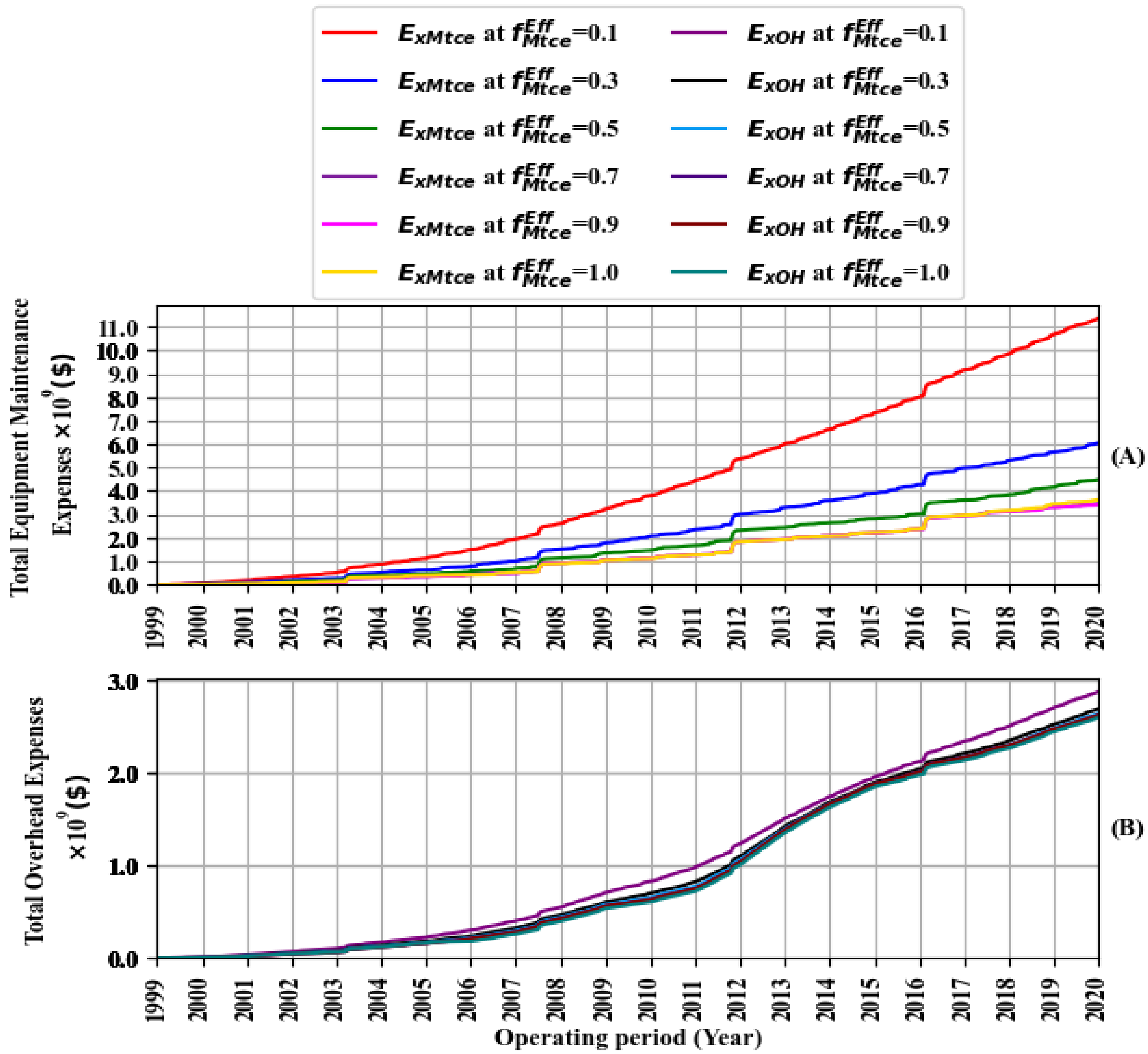

Figure 4.37: Effect of changes in maintenance effectiveness $\left(f_{Mtce}^{Eff}\right)$ on equipment maintenance expenses (E_{xMtce}) and overhead expenses (E_{xOH})

It was observed, however, that the TLCC increased and decreased correspondingly with respective increases and decreases in f_{Mtce}^{Eff} (Figure 4.38A). Further observation revealed that the drop in TLCC values at lowered f_{Mtce}^{Eff} values was caused by stoppages in LNG production activities due to increased unavailability of equipment (Figure 4.38A). This in turn affected the economic performance of the plant causing revenue reductions and lowered NPVs and PIs (Figure 4.38B). It was thus inferred from the results that poor maintenance effectiveness negatively affects LNG production and economic performances by increasing the costs incurred for extra spares for equipment maintenance materials, extra man-hours and loss of production and sales resulting from plant unavailability due to prolonged equipment downtime.

One observation of note was that a uniform increase in maintenance effectiveness produced corresponding concave increasing availability characteristics (Figure 4.38A). This implied that losses, revenue and profits occurring from plant downtime as a result of declining maintenance effectiveness, were likely to change non-linearly to the degree of f_{Mtce}^{Eff} in the plant. However, it was observed that this behaviour attained a plateau peak structure for the concerned quantities when $f_{Mtce}^{Eff} \geq 90\%$ implying that the best plant operation and economic performances are possible at equipment efficiencies between 0.9 and 1.

4.10.6 Maintenance strategy

The varying the firm's current equipment quality management parameter (P_k) in the plant to reflect the use of quality production equipment showed that increasing P_k values resulted in longer times to equipment failures. This resulted in lesser CM and PM frequencies. In addition, longer times to PM maintenance $\left(t_{TTPmk}^{Thr}\right)$ and increased system availability status (A_S^S) were observed. On the other hand, decreased P_k values caused increased equipment failure frequencies and shorter t_{TTPmk}^{Thr}, A_S^S were observed (Figure 4.39).

One interesting observation from the result is that although the plant availability currently stands at 89.86%, the system has a plant availability potential of up to 95.17% if the quality characteristics of the equipment are improved to the maximum.

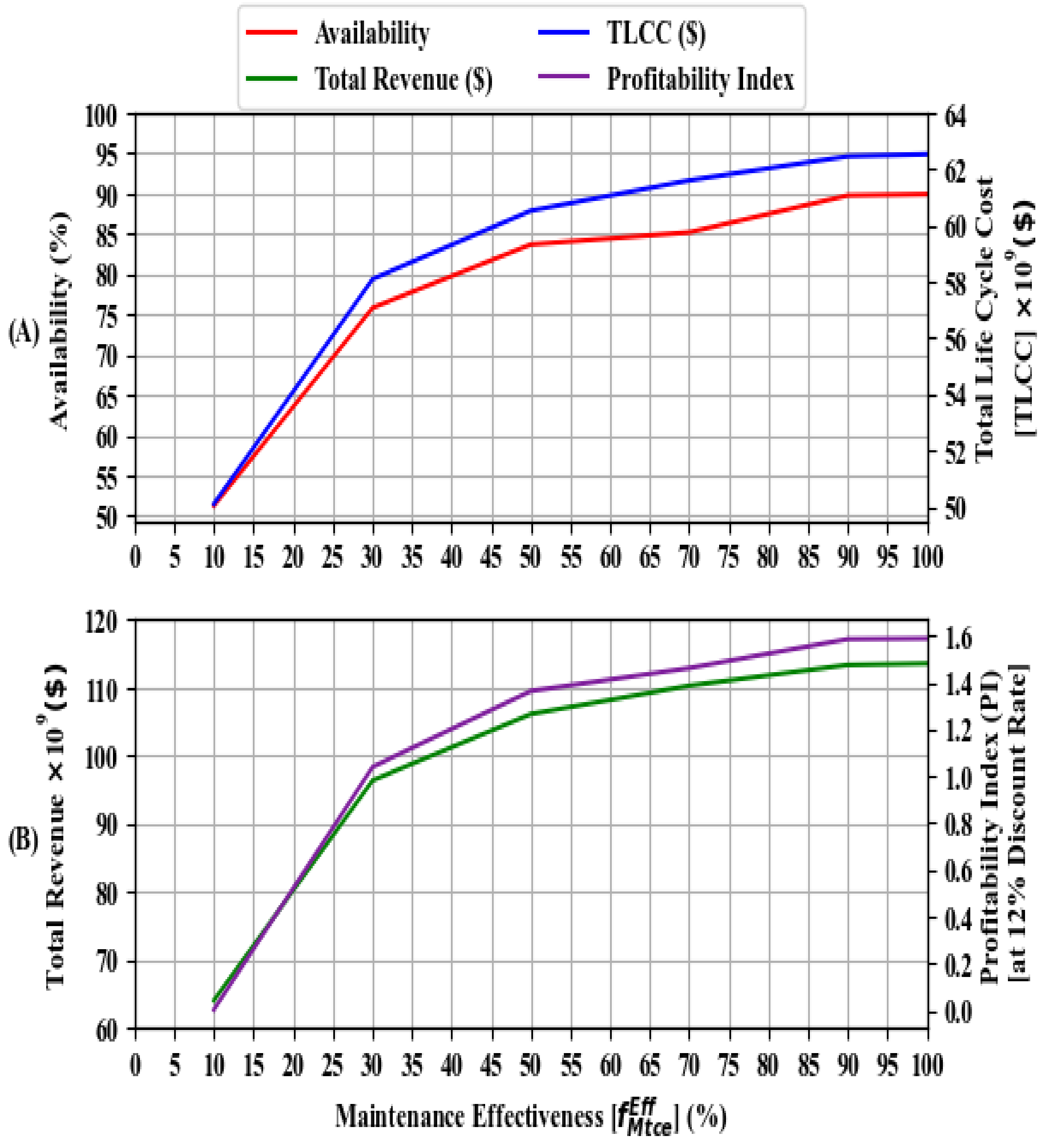

Figure 4.38: Effect of changes in maintenance effectiveness on availability, total life cycle cost, total revenue and profitability index

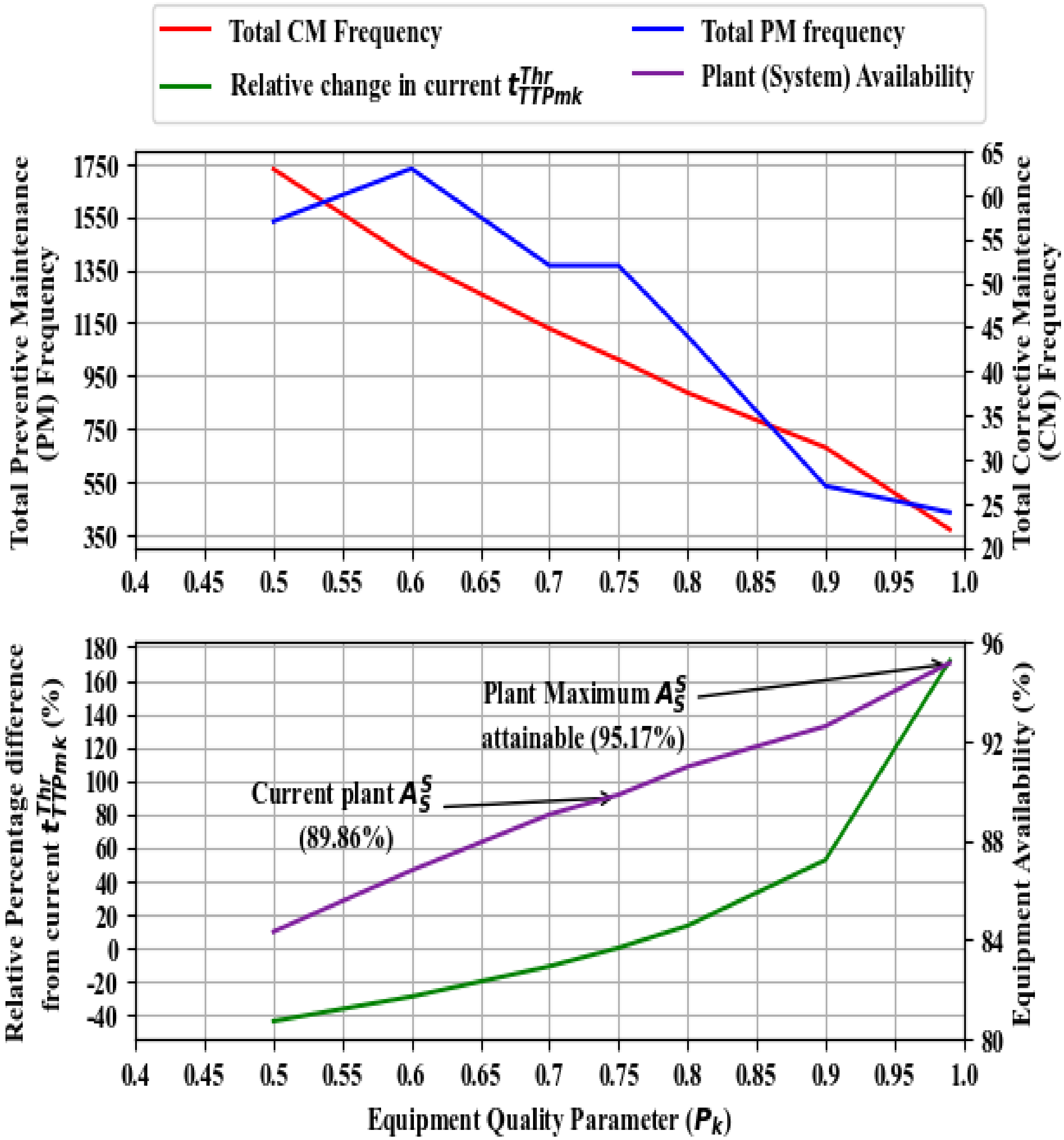

Figure 4.39: Effect of changes in equipment quality parameter on corrective and preventive maintenance frequencies, time to PM $\left(t^{Thr}_{TTPmk}\right)$ plant availability

The observed outcomes strengthen the argument for maintenance strategies that support the use of good quality equipment, reduction in equipment based-design and process cycle losses through thorough equipment sourcing procedures as well as the adoption of maintenance techniques that optimise the total equipment quality (Singh and Ahuja, 2012; Mokhatab *et al.*, 2014; Hung *et al.*, 2022).

4.10.7 Effect of charter speed

The current charter travel speed ($\bar{V} = 15.84\ knot/day$) falls just short of the range of charter speeds ($16 - 18\ 15.84\ knot/day$) maintained by LNG vessels in the global industry. The impact of varying $\bar{V}$ between extra slow streaming, slow streaming and normal vessel speeds ($\bar{V}_z$: $z = 9,11,13,15,17,21,23,25,27$) produced some interesting findings.

Figure 4.40 shows the impact of $\bar{V}_z$ on the amount of LNG produced, the number of shipment delivery, and delivery times. Figure 4.41 shows the effect of $\bar{V}_z$ on BOG generation, fuel requirement, BOG fuel fractions and BOG losses. The charter speed's impact on the cost of fuel and vessel charter is shown in Figure 4.42 while its effect on the TLCC, ROI, NPV and PI is displayed in Figure 4.43.

Firstly, it was observed that the maximum shipment deliveries were unaffected by charter speeds that are higher than 13 knot/day. However, a decline in the maximum number of shipment deliveries was observed to occur below the stated speed (Figure 4.41A). This implies that for the studied firm, LNG vessel operation below the speed of 13 knot/day will negatively affect expected LNG shipment delivery targets. This occurrence could lead to build-ups in storage facilities of production plants and possibly cause unplanned production stoppages and shutdowns. This would have an effect of lowered production output as was observed in the study (Figure 4.40B).

In addition, it was observed that the higher the charter speed, the higher the burn-off-gas (BOG) production rate by LNG transport vessels at sea (Figure 4.41A). As an example, for charter speeds of 13, 19 and 25 knots/day, the average daily BOG produced was 93.54, 94.52 and 95.01 tonnes/day equivalent to 4996.30, 5048.64, 5074.81 MMBTU/day respectively.

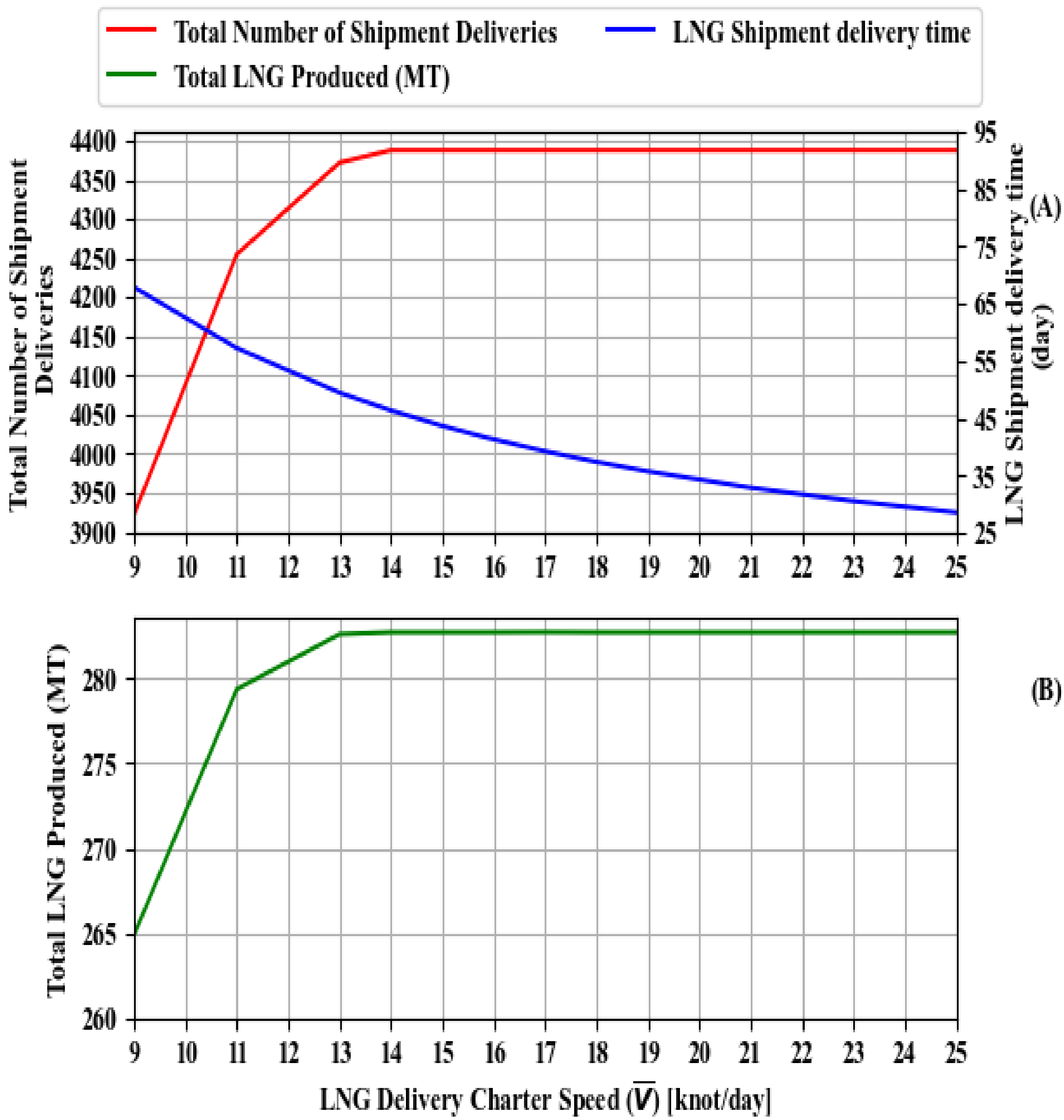

Figure 4.40: Effect of LNG delivery charter speed on the number of shipment delivery, delivery time, and total production volume

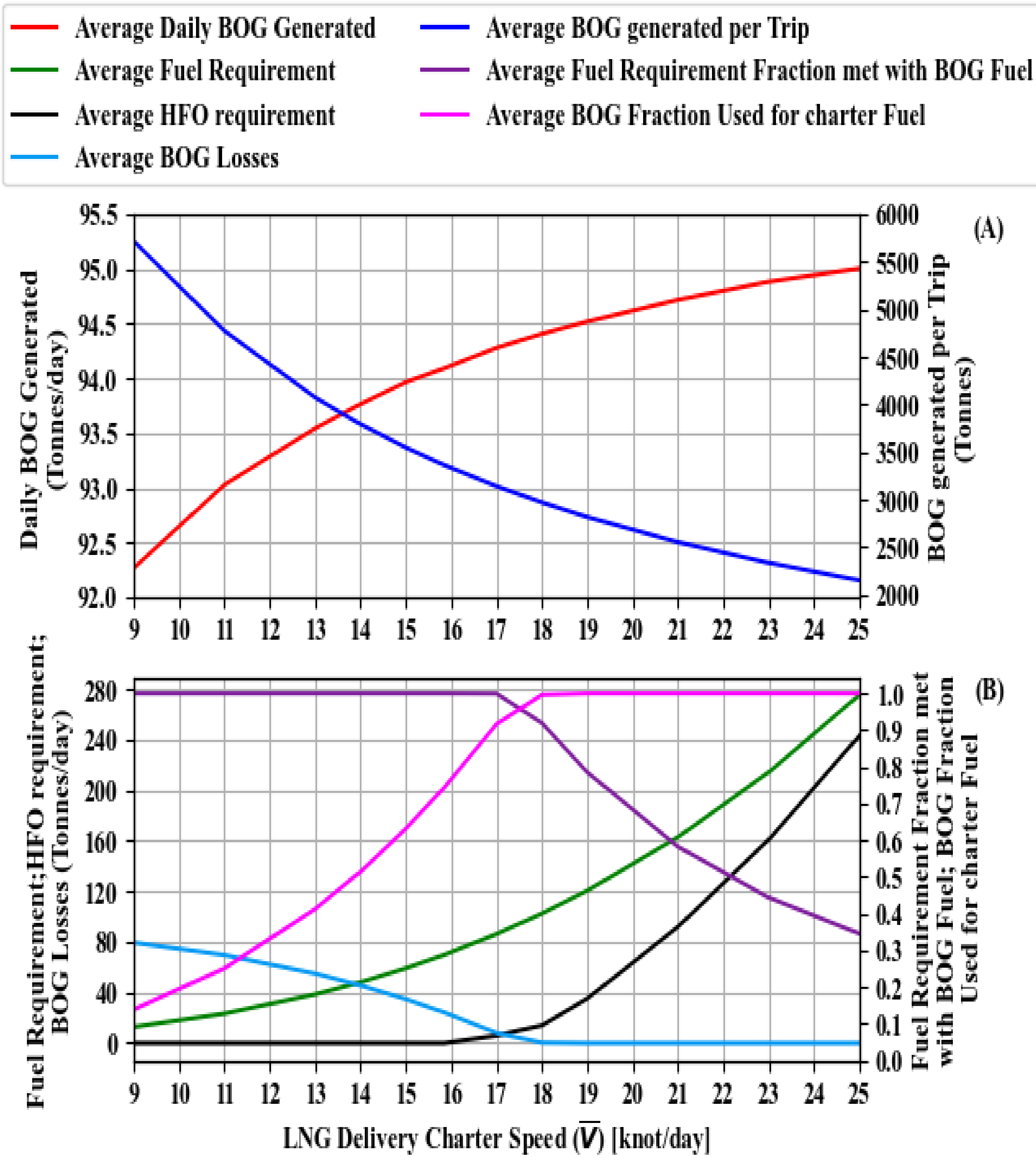

Figure 4.41: Effect of LNG charter speed on BOG generation, fuel requirement, BOG fuel fractions and BOG losses

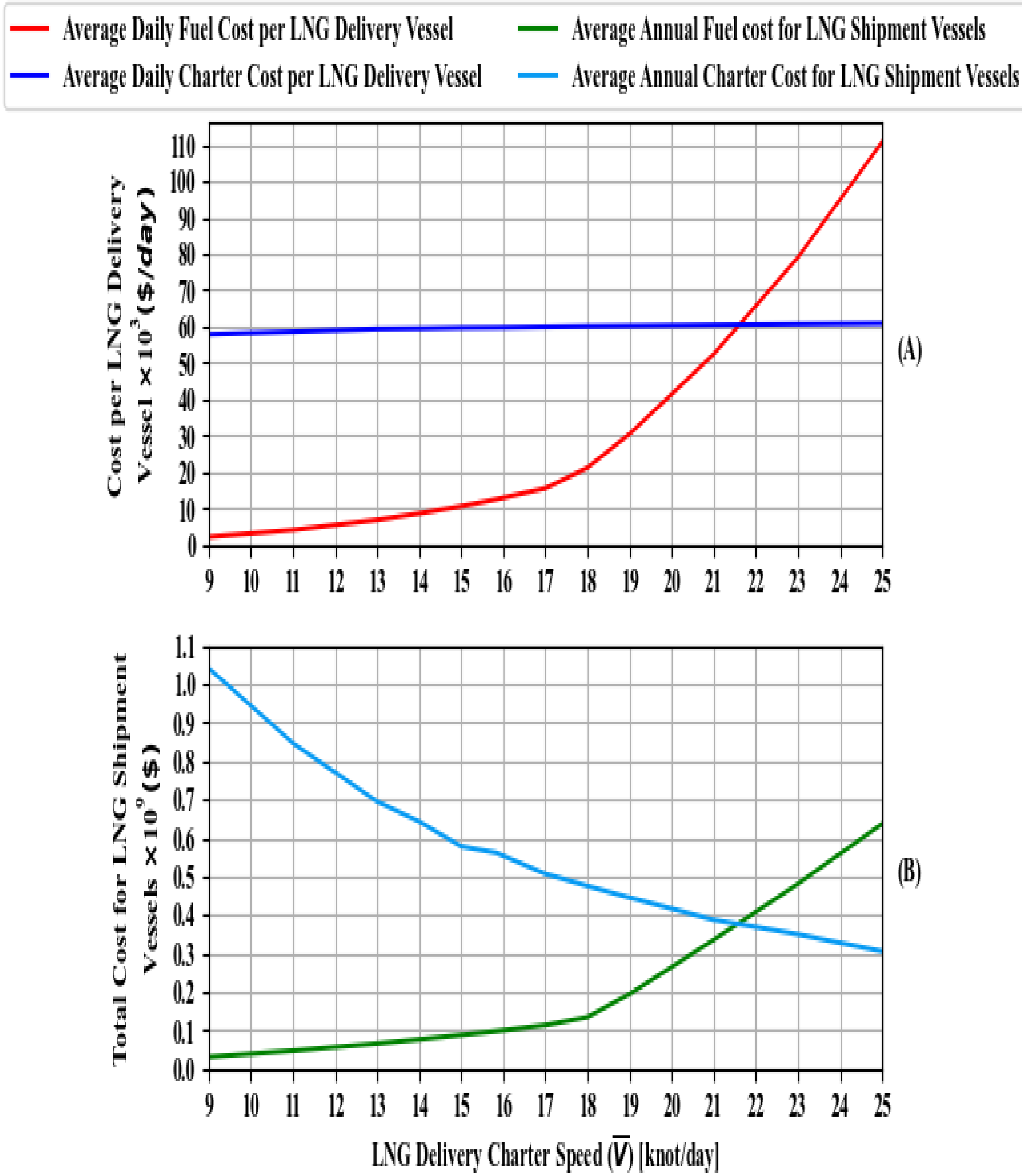

Figure 4.42: Impact of charter speed on fuel costs and charter costs for LNG shipment vessels

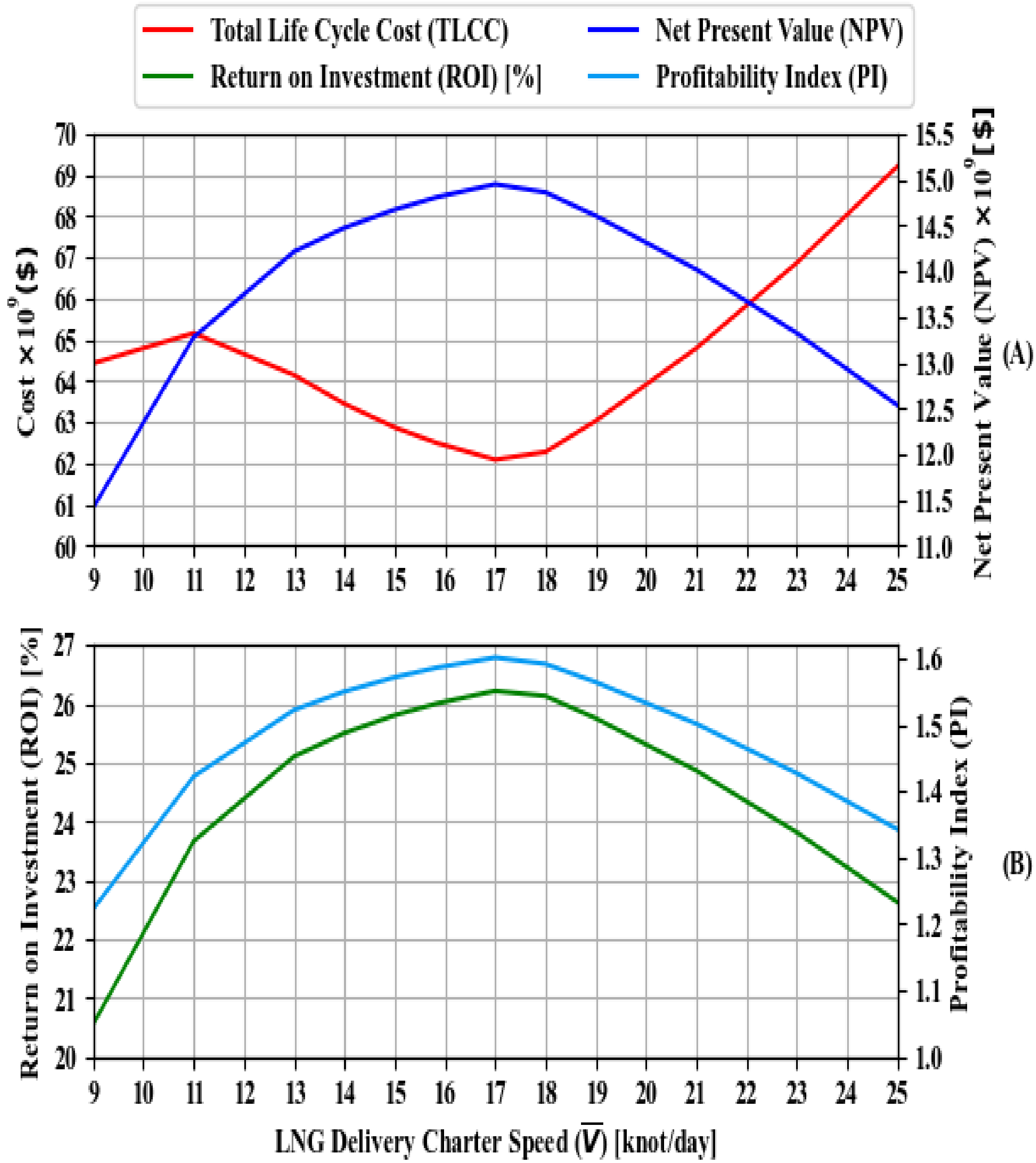

Figure 4.43: Effect of charter speed on total life cycle cost, net present value, return on investment and profitability index

However, lower charter speeds lead to an increase in the time spent by a vessel in transit thus affecting delivery times (Figure 4.40A). This caused an increase in the total volume of BOG generated per vessel trip (Figure 4.41A). Thus for the three cases being highlighted, the average BOG generated per trip was 4075.23, 2971.00 and 2151.96 tonnes/trip respectively.

Also, the percentage fraction of the BOG required as fuel for vessel power was observed to increase in exponential proportions to the charter speed. This caused the fraction of BOG used as fuel to increase with respect to increased charted speeds (Figure 4.41B). Some interesting observations were made from this behaviour and are here highlighted

(a) BOG losses decreased as the charter speed increased as larger proportions of BOG were consumed by vessels that operated at higher speeds.
(b) At charter speeds of 17 knots/day and above, BOG losses were zero as all BOG produced was used for fueling vessels.
(c) At charter speeds of 17 knots/day and above, BOG fuel became inadequate for laden and ballast journeys and heavy fuel oil (HFO) was used to augment this shortage.
(d) The amount of HFO requirement increased with respect to the increase in charter speed.

As a fallout of the observations highlighted, the unit cost of fueling the delivery vessels, increased in correspondence to the increment in charter speed (Figure 4.42A). In the context of the three charter speed cases (13, 19 and 25 knots/day) being highlighted, the respective unit fuel cost was $\$6.99\times10^3$, $\$30.55\times10^3$, and $\$110.72\times10^3$ corresponding to 63.58, 194.18 and 636.78 million dollars per year respectively. The results implied that operating the shipping vessels at lower speeds leads to lowered LCCs. However, as a result of spending more time in transit, the cost of vessel charter was observed to increase with decreasing charter speed (Figure 4.43B).

The conflicting impact of fuel cost and charter cost behaviour brings to the fore the need to determine a specific charter speed that just balances between minimising fuel costs and charter costs as well as being able to meet expected supply targets. The observation of the total shipping costs revealed 17 knots/day as the charter speed value that meets these requirements. It was observed that the minimum shipping cost of $\$12.18\times10^9$ and by extension a TLCC of $\$62.09\times10^9$ (Figure 4. 43A) corresponds to 17 knots/day. It was also observed that at this charter speed, the firm's LNG project accrued its highest ROI, NPV and PI (Figure 4. 43B).

CHAPTER FIVE

SUMMARY, CONCLUSION AND RECOMMENDATIONS

5.1 Summary

This study developed an LNG system Life Cycle based Cost estimation model using System Dynamics principles. Liquefied Natural gas cost-related quantities were identified by combining factory-work-participatory observation and literature review approaches. Inter-relationships between identified quantities were deduced and analyzed using causal loop and flow diagramming techniques. A set of differential equations of natural gas liquefaction process, plant maintenance activities and financial management processes were formulated applying the system dynamics methodology. Synthesizing these differential equations into a life cycle costing simulation model, economic evaluation was conducted for LNG business outcomes at different scenarios of LNG operations.

5.2 Conclusions

Based on the outcome of the study, the following conclusions were drawn:

(1) Capital expenditure (CAPEX) and operating expenditure (OPEX); NG-LNG prices; train capacity; required manpower; labour, discount and inflation rates; project life span (among others, see Table 4.1) were established as life cycle cost (LCC) drivers of the LNG system quantities;

(2) Operating performance-based inter-relationships among LNG system quantities have been established in form of causal loops and system flow diagrams and show that the total LNG shipment delivered is dependent on the production rate, OPEX fund availability, equipment availability, feed gas supply and workforce productivity;

(3) Dynamic governing equations with non-closed form characteristics describe the production, maintenance and financial and product supply processes of LNG sectors.

(4) Vensim PLE platform-based simulation model capable of determining the Life cycle and unit cost of a LNG project has been developed

(5) The investigated LNG plant's Greenfield CAPEX and Brownfield CAPEX were OPEX, 682.91×10^6, 476.47×10^6 \$/MTPA, respectively, while the total LCC and Unit production cost were \$$62.50\times10^9$ and 4.14 \$/MMBTU, respectively.

(6) The investigated LNG plant's made a return on investment of 26.01%, while its net present value and profitability index were \$$14.81\times10^9$ and 1.59, respectively.

5.3 Recommendations

In recent times, artificial intelligence predictive models have been found to favorably compare with the traditional approaches. The LNG cost drivers identified in this study may be useful independent variables for artificial neural network modeling LCC. This is more so given the large number of quantities (variables and parameters) and their complex interactions which the human capacity may not be able to fully understand or handled. The approach was however outside the scope of this study. It is hereby recommended for future investigations.

This model was developed for specifically for the life cycle cost analysis of the liquefied natural gas system. Nevertheless, the procedure for applying the system dynamics paradigm for life cycle costing proposed in the study has the potential to yield similar outcomes in petroleum refinery cost modeling based on the fact that LNG and refineries processes have similar operating sectors (Clews, 2016). In view of the significant contributions of this study, the method proposed could be attempted in Nigerian refineries as LCCs are useful tools for annual budgeting.

5.4 Contributions to Knowledge

The following are contributions to knowledge:

(1) A set of LNG Life Cycle Cost drivers;

(2) A system dynamics-based instrument for deriving LNG life cycle and unit costs.

(3) LNG factory operation simulator for selecting alternative LNG designs;

(4) LNG system causal loop and flow diagrams; and

(5) Governing dynamic equations of operating LNG sectors.

REFERENCES

Adebakin, I., and Ipaye, O. 2016. Project Delivery Delay: The Nigeria Experience. *IOSR Journal of Mechanical and Civil Engineering. 13*. 84-87. doi:10.9790/1684-1305058487

Adegbuyi, P., & Asapo, E. 2010. The Effect of Production Planning and Budgeting on Organizational Productivity. *Leonardo Electronic Journal of Practices and Technologies 9*.

Ajayeoba, A., Raheem, W., & Adebiyi, K. 2019. Development of a System Dynamic Model for Sawmill Safety System. *Advanced Engineering Forum. 32*. 63-74. doi:10.4028/www.scientific.net/AEF.32.63

Adekomaya, O., Jamiru, T., Sadiku, R., Huan, Z., and Sulaiman, M. 2016. Gas flaring and its impact on electricity generation in Nigeria. *Journal of Natural Gas Science and Engineering. 29*. 1-6. doi:https://doi.org/10.1016/j.jngse.2015.12.042

Agbon, I. S. 2000. *A Cost Effective Analysis of Nigerian LNG.* Paper presented at the Society of Petroleum Engineers International Oil and Gas Conference and Exhibition, Beijing, China.

Aisha, P. 2021. Top 2 Methods of Costing | Accounting. https://www.accountingnotes.net/cost-accounting/costing-methods/top-2-methods-of-costing-accounting/10169

Akina. 2021. Current status and future prospects of LNG fuel for ships. Retrieved 22 February, 2022 from https://www.mol-service.com/blog/lng-as-ships-fuel

Al-Hawari, T., Gailan Qasem, A., Smadi, H., Arauydah, H., & Al Theeb, N. 2022. The effects of pre or post delay variable changes in discrete event simulation and combined DES/system dynamics approaches in modelling supply chain performance. *Journal of Simulation 16*. 2: 147-165. doi:10.1080/17477778.2020.1764399

Al-Saadoon, F., & Nsa, A. 2009. Economics of LNG Projects. doi:10.2118/120745-MS

AlArjani, A., Nasseef, M. T., Kamal, S. M., Rao, B. V. S., Mahmud, M., & Uddin, M. S. 2022. Application of Mathematical Modeling in Prediction of COVID-19 Transmission Dynamics. *Arabian Journal for Science and Engineering 47*. 8: 10163-10186. doi:10.1007/s13369-021-06419-4

Andeobu, L., Hettihewa, S., and Wright, C. S. 2005. Risk management in the extractive industry: An empirical investigation of the Nigerian oil and gas industry. *Journal of Applied Business and Economics. 17*. 1. 86 - 102.

Andeobua, L., Hettihewa, S., and Wright, C. S. 2010. *Australian and Nigerian LNG Projects: Insights for resolving challenges facing new LNG projects.* Paper presented at the Proceedings of 4th Global Business and Finance Research Conference, Marriott Hotel, Melbourne, Australia. 25 - 27 May 2015.

Angelsen, S., Consulting, G., Tronskar, J., & Uznanski, D. 2006. *Maintenance and inspection planning for LNG liquefaction plants and terminals*.

Anosike, N., El-Suleiman, A., and Pilidis, P. 2016. Associated Gas Utilization Using Gas Turbine Engine, Performance Implication—Nigerian Case Study. *Energy and Power Engineering. 08*. 137-145. doi:10.4236/epe.2016.83012

Arabian Business. 2011. LNG insurance rates jump on lawless waters, piracy. Retrieved 28 June, 2022 from https://www.arabianbusiness.com/gcc/lng-insurance-rates-jump-on-lawless-waters-piracy-419273

Attah, E. E. 2020. *An analysis of the propulsion and powering options for LNG carriers.* (Doctor of Phylosophy), University College London, United Kingdom. Retrieved 23 June 2022 from: https://discovery.ucl.ac.uk/id/eprint/10119327/1/Ekanem%20Attah__Thesis.pdf

Aurich, J. C., Lauer, C., Faltin, M., & Schweitzer, E. 2009. Life cycle cost estimation for new developed manufacturing processes. *ZWF Zeitschrift fuer Wirtschaftlichen Fabrikbetrieb 104*: 720-724.

Axelsen, J. J. 2018. *A study of the operational patterns of LNG carriers from AIS data.* (Master in Engineering with specialization in Marine System Design Masters), Norwegian University of Science and Technology, Norway. Retrieved 23 June 2022 from https://ntnuopen.ntnu.no/ntnu-xmlui/bitstream/handle/11250/2564502/19159_FULLTEXT.pdf?sequence=1

Ayuk, N. J. 2022. No better time: African oil and gas capex spending reflects demand, creates opportunity. Retrieved 10 November, 2022 https://energychamber.org/no-better-time-african-oil-and-gas-capex-spending-reflects-demand-creates-opportunity/

Azar, A. 2012. System dynamics as a useful technique for complex systems. *International Journal of Industrial and Systems Engineering 10*: 377-410. doi:10.1504/IJISE.2012.046298

Azzi, A., Battini, D., Faccio, M., Persona, A., and Sgarbossa, F. 2014. Inventory holding costs measurement: A multi-case study. *The International Journal of Logistics Management. 25*. doi:10.1108/IJLM-01-2012-0004

Baatz, Y. 2018. Charterparties *Maritime Law* (4 ed.). Ed. Y. Baatz. New York, USA Informa Law from Routledge. Chapter 4: 251-311

Bae, S.-T., Cho, G.-S., and Hwang, H. S. 2007. Multi-state Availability Model for Manufacturing System Considering System Cost. *International Journal of Information Systems for Logistics and Management. 2*. 2. 93-98.

Bahgat, W. 2015. Proposed Method for Dealing with Boil-off Gas on board LNG Carriers during Loaded Passage. *International Journal of Multidisciplinary and Current Research. 3*. 508 - 512. doi:10.14741/Ijmcr/23213124/3.3.2015.20

Barclay, M., and Shukri, T. 2000. Enhanced single mixed refrigerant process for stranded gas liquefaction. Paper presented at the 79th Annual GPA Convention, Atlanta. Retrieved 30 June, 2022 from http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG%20Conferences/2007/fscommand/PO_24_Barclay_s.pdf

Barrass, C. B. 2004. *Ship Design and Performance for Masters and Mates*. London: Elsevier Butterworth-Heinemann.

Barrios, K. 2018. Should I hedge my bets and sign short-term shipping contracts? Retrieved 30 June, 2022 https://www.xeneta.com/blog/should-i-sign-short-term-shipping-contracts.

Basak, M., Perrons, R., & Coffey, V. 2019. Schedule overruns as a barrier for liquefied natural gas projects: A review of the literature and research agenda. *Energy Reports 5*: 210-220. doi:10.1016/j.egyr.2019.01.008

Bialystocki, N., and Konovessis, D. 2016. On the estimation of ship's fuel consumption and speed curve: A statistical approach. *Journal of Ocean Engineering and Science. 1*. 2. 157-166. doi:https://doi.org/10.1016/j.joes.2016.02.001

Bipul, N. 2016. *Impact of the U.S. shale gas export on East Asia LNG trading and pricing by 2020*. (Master of Science), Erasmus University Rotterdam, Netherland. Retrieved 23 June 2022 from: https://shareok.org/bitstream/11244/319697/1/2019_daSilvaSequeira_Pascoela_Thesis.pdf

Blank, L., and Tarquin, A. 2005. *Engineering economy* (7 ed.). New York, USA: McGraw-Hill.

Brehmer, B. 1989. *Feedback Delays and Control in Complex Dynamic Systems*, Berlin, Heidelberg.

Brignall, T. J., Fitzgerald, L., Johnston, R., and Silvestro, R. 1991. Product Costing in Service Organisations. *Management Accounting Research. 2*. 227-248. doi:10.1016/S1044-5005(91)70036-X

Buls, B. 2022. LNG marine fuel usage for ships is growing. Retrieved 02 August, 2022 from https://www.workboat.com/lng-marine-fuel-usage-for-ships-is-growing

Cacciapalle, M., Roberts, M., and Ott, C. 2021. Leave refrigerants out in the cold. Retrieved 10 October, 2022 from: https://www.airproducts.com/-/media/airproducts/files/en/lng/advantages-of-gas-expansion-processes_oct2021_article.pdf?la=enandhash=A20BF5ED98A22F8805A011D7598CA676

Calixto, E. 2016. *Gas and oil reliability engineering modeling and analysis* (2nd ed.). Oxford, United Kingdom: Gulf Professional Publishing.

Caro, J. J., & Möller, J. 2016. Advantages and disadvantages of discrete-event simulation for health economic analyses. *Expert Review of Pharmacoeconomics & Outcomes Research 16*. 3: 327-329. doi:10.1586/14737167.2016.1165608

Castillo, L., Nadales, R., González, C., Dorao, C. A., and Viloria, A. (2010). *Technology selection for liquefied natural gas (LNG) on baseload plants.* Paper presented at the International Gas Convention AVPG Caracas, Venezuela.

Caswell, C. 2019. Does (train) size really matter? Retrieved 16 June, 2022 from https://www.gti.energy/wp-content/uploads/2019/10/199-LNG19-05April2019-Caswell-Christopher-paper.pdf

Charles-Owaba, O. E., & Adebiyi, K. 2006. The development of manufacturing safety programme simulator. *Journal of Modelling in Management. 1*. 270-290. doi:10.1108/17465660610715249

Chandra, V. 2020. Why Is Natural Gas Priced Differently Around The World? . Retrieved 22 February, 2022 from: https://www.geoexpro.com/articles/2020/12/why-is-natural-gas-priced-differently-around-the-world

Chaplin, Z. 2017. Major accident hazard pipeline failure frequency calculation using fracture mechanics. *Safety and Reliability. 37*. 4. 217-232. doi:10.1080/09617353.2018.1524679

Chen, J. 2022. Profitability Index (PI): Definition, components, and formula. Retrieved 16 November, 2022 from: https://www.investopedia.com/terms/p/profitability.asp

Cheng, S.-R., Lin, B., Hsu, B.-M., and Shu, M.-H. 2009. Fault-tree analysis for liquefied natural gas terminal emergency shutdown system. *Expert Systems with Applications. 36*. 9. 11918-11924. doi:https://doi.org/10.1016/j.eswa.2009.04.011

Clancey, J. 2021. Process Costing: What It Is and Why It's Important. Retrieved 30 June, 2022 from https://www.netsuite.com/portal/resource/articles/accounting/process-costing.shtml

Clews, R. J. 2016. *Project finance for the international petroleum industry*. United Kingdom: Elsevier.

Collins, A. J., Sabz Ali Pour, F., & Jordan, C. A. 2023. Past challenges and the future of discrete event simulation. *The Journal of Defense Modeling and Simulation 20*. 3: 351-369. doi:10.1177/15485129211067175

Cox, K. 2022. Calculating the break-even analysis for your business. Retrieved 5 December, 2023 from: https://www.nav.com/blog/breakeven-analysis-calculation-1680530/

Coyle, D. A., Durr, C. A., and Hill, D. K. 1998. "Cost optimization," The contractor's approach. Retrieved 5 December, 2023 from: http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG%20Conferences/1998/Papers/7-3-Hill.PDF

Coyle, R. G. 1996. *System Dynamics Modelling: A practical approach*. United Kingdom: Chapman and Hall.

Cunha, S. 2012. *Comparison and Analysis of Pipeline Failure Statistics*. Paper presented at the Proceedings of the 2012 9th International Pipeline Conference IPC2012 Alberta, Canada.

Da Silva Sequeira, P. M. (2019). *Economy analysis comparison for liquefied natural gas and gas-to-liquid project in monetizing excessive natural gas production.* (Master of Science), University of Oklahoma, USA. Retrieved 23 June 2022 from: https://shareok.org/bitstream/11244/319697/1/2019_daSilvaSequeira_Pascoela_Thesis.pdf

Department of Energy. 2013. Liquefied natural gas: Understanding the basic facts. Retrieved 14 August, 2020 from: https://energy.gov/sites/prod/files/2013/04/f0/LNG_primerupd.pdf

Department of Petroleum Resources. 2018. 2017 Nigerian oil and gas industry annual report. Retrieved 03 January, 2022 from: https://www.nuprc.gov.ng/oil-gas-industry-annual-reports-ogiar/

Department of Petroleum Resources. 2019. 2018 Nigerian oil and gas industry annual report. Retrieved 03 January, 2022 from: https://www.nuprc.gov.ng/oil-gas-industry-annual-reports-ogiar/

DiNapoli, R. N., and Yost, C. C. 1998. LNG plant costs: present and future trends. 1 - 14. Retrieved 13 June, 2020 from: http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG%20Conferences/1998/Papers/7-4-DiNapoli.PDF

Dirk, P. 2009. Study of equipment prices in the power sector. Energy Sector Management Assistance Program (ESMAP) Technical Paper 122/09. Retrieved January 17, 2020 from: https://esmap.org/sites/default/files/esmap-files/TR122-09_GBL_Study_of_Equipment_Prices_in_the_Power_Sector.pdf

DNV. 2020. Where's LNG investment heading? Retrieved 30 June, 2022 https://www.dnv.com/oilgas/perspectives/wheres-lng-investment-heading.html

Doug Yates, P. E. 2002. Thermal efficiency - deign, life cycle and environmental considerations in LNG plant design. Retrieved 10 October, 2022 hhttps://static.conocophillips.com/files/resources/smid_016_thermal_efficiency.pdf

Drury, C. 2018. *Management and Cost Accounting* (10 ed.). Andover, Hampshire, United Kingdom: Cengage Learning EMEA.

Dugaal, A. 2022. The impact of budgetary control on manufacturing firms' financial performance Mogadishu - Somalia. *NeuroQuantology 20*: 4741-4755.

Dunn, R. L. 1999. Basic guide to maintenance benchmarking. 16. Retrieved 11 September, 2021 from: https://www.plantengineering.com/articles/basic-guide-to-maintenance-benchmarking/

Eaton, A., Hernandez, R., Risley, A., Hunter, P., Avidan, A., and Duty, J. 2004. Lowering lng unit costs through large and efficient lng liquefaction trains – what is the optimal train size? . Retrieved 16 June, 2022 from: https://static.conocophillips.com/files/resources/smid_016_aiche.pdf

Eikens, M. 2020. Economics of the lng value chain. Retrieved 13 August, 2022 from: https://www.econnectenergy.com/articles/economics-of-the-lng-value-chain#:~:text=Upstream%20development%3A%2010%2D11%20%25,%3A%2020%20%2D%2030%20%25%20of%20costs

Eise Fokkema, J., Buijs, P., and Vis, I. F. A. 2017. An investment appraisal method to compare LNG-fueled and conventional vessels. *Transportation Research Part D: Transport and Environment. 56*. 229-240. doi:https://doi.org/10.1016/j.trd.2017.07.021

Ejiogu, A. R. 2013. GAS flaring in nigeria: costs and policy. *Energy and Environment. 24*. 6. 983-998.

Elehinafe, F. B., Nwizu, C. I., Odunlami, O. B., and Ibukun, F. D. 2022. Natural Gas Flaring in Nigeria, its Effects and Potential Alternatives – A Review. *Journal of Ecological Engineering. 23*. 8. 141-151. doi:10.12911/22998993/149822

Emblemsvåg, J. 2003. *Life-Cycle Costing Using Activity-Based Costing and Monte Carlo Methods to Manage Future Costs and Risks*. USA: John Wiley and Sons, Inc., New Jersey.

engineerforum. 2022. Salary details Of Shell, Total, Mobil, Schlumberger, Chevron and NLNG. Retrieved 10 August, 2022 from: https://engineersforum.com.ng/2020/08/27/salary-details-of-shell-total-mobil-schlumberger-chevron-and-nlng/

Exchange Rates UK. 2022. US Dollar to Nigerian Naira Spot Exchange Rates for 2014. Retrieved 10 August, 2022 https://www.exchangerates.org.uk/USD-NGN-spot-exchange-rates-history-2014.html#:~:text=Average%20exchange%20rate%20in%202014%3A%20165.15%20NGN.

Eydman, M. 2017. Comparison of Job Order and Process Costing.

Farr, J. V., and Faber, I. 2019. *Engineering Economics of Life Cycle Cost Analysis*. USA: CRC Press.

Farsi, M., Erkoyuncu, J. A., & Harrison, A. 2020. *A Super Simple Life-cycle Cost Estimation Model with Minimum Data Requirement*. Paper presented at the 9th International Conference on Through-life Engineering Services Cranfield University, UK.

Fernández, I. A., Gómez, M. R., Gómez, J. R., and Insua, Á. B. 2017. Review of propulsion systems on LNG carriers. *Renewable and Sustainable Energy Reviews. 67*. 1395-1411. doi:https://doi.org/10.1016/j.rser.2016.09.095

Fisher, J., and Krumwiede, K. 2012. Product Costing Systems: Finding the Right Approach. *Journal of Corporate Accounting and Finance. 23*. doi:10.1002/jcaf.21752

Forto. 2016. Is it Time to Negotiate Long Term Freight Rates? Retrieved 30 June, 2022 https://forto.com/en/blog/time-negotiate-long-term-freight-rates/

Gallagher, P. 2018. A guide to FLNG (floating liquefied natural gas). Retrieved 16 June, 2022 from: https://www.oilandgasiq.com/fpso-flng/articles/guide-to-flng

Glerum, A. 2014. Static and dynamic mathematical models of behavior.

Gomez, M. 2013. LNG Capital Expenditure. 1 - 14. Retrieved 29 May, 2022 from: https://www.marinelink.com/news/expenditure-capital-lng359015

Gowid, S., Dixon, R., and Ghani, S. 2014. Optimization of reliability and maintenance of liquefaction system on FLNG terminals using Markov modelling. *International Journal of Quality and Reliability Management. 31*. doi:10.1108/IJQRM-12-2012-0156

Gowid, S., Dixon, R., and Ghani, S. 2015. Profitability, reliability and condition based monitoring of LNG floating platforms: A review. *Journal of Natural Gas Science and Engineering. 27*. 1495-1511. doi:https://doi.org/10.1016/j.jngse.2015.10.015

Grzesiak, S. 2018. Alternative Propulsion Plants for Modern LNG Carriers. *New Trends in Production Engineering. 1*. 1. 399-407. doi:doi:10.2478/ntpe-2018-0050

Gupta, B., and Prasad, K. S. 2003. Future of lng transportation: Various propulsion alternatives. Retrieved 16 November, 2022 from: https://www.dieselduck.info/machine/02%20propulsion/LNG%20Transport%207%20of%207.pdf

Habibullah, A., and Kikkawa, Y. 2018. *Strategies for LNG Project Development*.

Hajji, A., Chahartaghi, M., and Kahani, M. 2019. Thermodynamic analysis of natural gas liquefaction process with propane pre-cooled mixed refrigerant process (C3MR). *Cryogenics. 103*. 102978. doi:https://doi.org/10.1016/j.cryogenics.2019.102978

Hamoudi, K., Bellaouar, A., and Petiot, R. 2021. A Model of Systems Dynamics for Physical Flow Analysis in a Distribution Supply Chain. *Transport and Telecommunication Journal. 22*. 1. 98-108. doi:doi:10.2478/ttj-2021-0008

Harraz, H. 2016. Petroleum industry structure (Publication no. 10.13140/RG.2.1.4699.7363). Retrieved 21 March, 2022

Hassan, J., Thodi, P., and Khan, F. 2016. Availability analysis of a LNG processing plant using the Markov process. *Journal of Quality in Maintenance Engineering. 22*. 302-320. doi:10.1108/JQME-05-2012-0018

Henley, S. S., Golden, R. M., & Kashner, T. M. 2020. Statistical modeling methods: challenges and strategies. *Biostatistics & Epidemiology 4*. 1: 105-139. doi:10.1080/24709360.2019.1618653

Herdzik, J. 2015. Aspects of using lng as a marine fuel. *Journal of KONES. Powertrain and Transport. 19*. 201-209. doi:10.5604/12314005.1137919

Hirschhausen, C. v., Neumann, A., Ruester, S., and Auerswald, D. 2008. Advice on the opportunity to set up an action plan for the promotion of LNG chain investments - economic, market, and financial point of view -final report. Retrieved 30 June, 2022 https://globallnghub.com/articles/action-plan-for-the-promotion-of-lng-chain-investment

Hönig, V., Prochazka, P., Obergruber, M., Smutka, L., and Kučerová, V. 2019. Economic and technological analysis of commercial LNG production in the EU. *Energies. 12*. 8. 1565.

Houwer, H. M. 2015. Unlocking the supply chain for LNG project success. Retrieved October 9, 2021 from: https://assets.kpmg/content/dam/kpmg/pdf/2015/03/unlocking-supply-chain-LNG-project-success.pdf

Hu, W., Camacho, E. F., and Xie, L. 2014. Feedforward and Feedback Control of Dynamic Systems. *IFAC Proceedings Volumes. 47*. 3. 7741-7748. doi:https://doi.org/10.3182/20140824-6-ZA-1003.02313

Hung, Y.-H., Li, L. Y. O., and Cheng, T. C. E. 2022. Uncovering hidden capacity in overall equipment effectiveness management. *International Journal of Production Economics. 248*. 108494. doi:https://doi.org/10.1016/j.ijpe.2022.108494

IEA. 2020. Gas 2020. Retrieved 30 June, 2022 https://www.iea.org/reports/gas-2020

Inkpen, A., and Moffett, M. H. 2011. *The global oil gas industry: Management, strategy and finance*. Oklahoma, USA: PennWell Corporation.

International Energy Agency. 2003. South American Gas (Publication no. doi:https://doi.org/10.1787/9789264195820-en). Retrieved 9 July, 2022 from: https://www.oecd-ilibrary.org/content/publication/9789264195820-en

International Gas Union. 2012a. 2011 World LNG report. Retrieved 17 June, 2022 from: https://www.igu.org/resources/?pages=6andsection=

International Gas Union. 2012b. Natural Gas Conversion Pocketbook. Retrieved March 10, 2020 from: http://members.igu.org/old/IGU%20Events/wgc/wgc-2012/wgc-2012-proceedings/publications/igu-publications

International Gas Union. 2013. 2013 World LNG report. Retrieved 17 June, 2022 from: https://www.igu.org/resources/?pages=5andsection=

International Gas Union. 2014. 2014 World LNG report. Retrieved 17 June, 2022 from: https://www.igu.org/resources/?pages=5andsection=

International Gas Union. 2015. 2015 World LNG report. Retrieved 17 June, 2022 from: https://www.igu.org/resources/?pages=5andsection=

International Gas Union. 2017. 2017 World LNG report. Retrieved 17 June, 2022 from: https://www.igu.org/resources/?pages=3andsection=

International Gas Union. 2018. 2018 World LNG report. Retrieved 17 June, 2022 from: https://www.igu.org/resources/?pages=2andsection=8

International Gas Union. 2019. 2019 World LNG report. Retrieved 17 June, 2022 from: https://www.igu.org/resources/?pages=2andsection=

International Gas Union. 2020. 2020 World LNG report. Retrieved 17 June, 2022 from: https://www.igu.org/resources/#igu-reports

International Gas Union. 2022. 2022 World LNG report. Retrieved 17 June, 2022 from: https://www.igu.org/resources/#igu-reports

Ismaila, U., Jung, W., and Park, C. Y. 2022. Delay Causes and Types in Nigerian Power Construction Projects. *Energies. 15*. 3. 814.

Itegboje, J. O. 2018. *The growth of agency labour in the Nigerian oil industry and its challenges for trade union organisation.* (Doctor of Philosophy), University of Salford, United Kingdom. Retrieved 23 June 2022 from: https://usir.salford.ac.uk/47339/1/C__Users_bwp366_Desktop_JOAN%20FINAL%20PhD%20THESIS.pdf

JASE-W. 2022. High-efficiency Ethane and LPG Recovery Process (Publication no. doi:https://doi.org/10.1787/9789264195820-en). Retrieved 7 December, 2022 https://www.jase-w.eccj.or.jp/technologies/pdf/oil_refinery_chemicals/P-08.pdf

Jenkins, S. 2017. Current economic trends: CEPCI January (Prelim.) and December (Final). Retrieved 2 February 2022, from Gulf Publushing Holdings LLC https://www.chemengonline.com/current-economic-trends-cepci-january-prelim-and-december-final

Jovanoski, B., Minovski, R., Voessner, S., & Lichtenegger, G. 2012. Combining system dynamics and discrete event simulations - Overview of hybrid simulation models. *Journal of Applied Engineering Science 10*: 135-142. doi:10.5937/jaes10-2512

Kadarova, J., Kobulnický, J., and Teplická, K. 2015. Product Life Cycle Costing. *Applied Mechanics and Materials. 816*. 547-554. doi:10.4028/www.scientific.net/AMM.816.547

Kalikatzarakis, M., Theotokatos, G., Coraddu, A., Sayan, P., and Wong, S. Y. 2022. Model based analysis of the boil-off gas management and control for LNG fuelled vessels. *Energy. 251*. 123872. doi:https://doi.org/10.1016/j.energy.2022.123872

Kar, S. K. 2019. Energy security and sustainability: Role of natural gas in indian context. *PDPU Journal of Energy and Management. 3*. 2.

Kawauchi, Y., and Rausand, M. 1999. Life Cycle Cost (LCC) Analysis in Oil and Chemical Process Industries.

Keller, P. 2021. The Outlook for LNG as a Marine Fuel. Retrieved 22 February, 2022 https://maritime-executive.com/editorials/the-outlook-for-lng-in-2021

Khan, M. I., and Islam, M. R. 2007. *Transportation, Processing, and Refining Operations*. Houston, USA: Gulf Publishing Company.

Khan, M. S., Karimi, I. A., and Wood, D. A. 2017. Retrospective and future perspective of natural gas liquefaction and optimization technologies contributing to efficient LNG supply: A review. *Journal of Natural Gas Science and Engineering. 45*. 165-188. doi:https://doi.org/10.1016/j.jngse.2017.04.035

Kim, K., Park, K., Roh, G., and Chun, K. 2019. Case Study on Boil-Off Gas (BOG) Minimization for LNG Bunkering Vessel Using Energy Storage System (ESS). *Journal of Marine Science and Engineering. 7*. 30. 1-18. doi:10.3390/jmse7050130

Kiriya, N. 2000. Statistical study on reliability of ship equipment and safety management — reliability estimation for failures on main engine system by ship reliability database system *Bulletin of the JIME. 29*. 2. 64-70.

Kohler, T., Bruentrup, M., Key, R. D., and Edvardsson, T. 2014. Choose the best refrigeration technology for small-scale LNG production. Retrieved 20 August, 2021 from: https://www.linde-engineering.com/en/images/41469_ePrint.pdf_tcm19-129829.pdf

Kolosowski, M., and Chwastyk, P. 2014. Economic Aspects of Company Processes Improvement. *Procedia Engineering. 69*. 222-230. doi:https://doi.org/10.1016/j.proeng.2014.02.225

Kotzot, H., Durr, C., Coyle, D., and Caswell, C. 2009. Five major factors in LNG plant design. Retrieved 28 June, from 2022 https://www.hartenergy.com/news/five-major-factors-lng-plant-design-50357

Koul, S., Falebita, O., Akinbami, J.-F., and Akarakiri, J. 2016. System dynamics, uncertainty and hydrocarbon resources modelling: A systematic review. *Renewable and Sustainable Energy Reviews. 59*. 199-205. doi:10.1016/j.rser.2015.12.088

Kouzelis, K., Frouws, K., and van Hassel, E. 2022. Maritime fuels of the future: what is the impact of alternative fuels on the optimal economic speed of large container vessels. *Journal of Shipping and Trade. 7*. 1. 23. doi:10.1186/s41072-022-00124-7

Kowgier, H. 2022. Selected Mathematical-Economics Theoretical Models of the Static Equilibrium of the Demand-Supply Type. *Procedia Computer Science. 207*. 1850-1860. doi:https://doi.org/10.1016/j.procs.2022.09.243

Kwang Pil, C., Rausand, M., and Vatn, J. 2008. Reliability assessment of reliquefaction systems on LNG carriers. *Reliability Engineering and System Safety. 93*. 9. 1345-1353. doi:https://doi.org/10.1016/j.ress.2006.11.005

Lawrence, G. 2012. Cost estimating for turnarounds *Petroleum Technology Quarterly. Q1*. 33-43.

Lee, H.-J., Yoo, S.-H., and Huh, S.-Y. 2020. Economic benefits of introducing LNG-fuelled ships for imported flour in South Korea. *Transportation Research Part D: Transport and Environment. 78*. 102220. doi:https://doi.org/10.1016/j.trd.2019.102220

Lee, I., Cho, S., Lee, S., and Moon, I. 2016. Case Studies for SMR Natural Gas Liquefaction Plant by Capacity in Small Scale Gas Wells through Cost Analysis. *Journal of the Korean Institute of Gas. 20*. 46-51. doi:10.7842/kigas.2016.20.3.46

Lee, I., Park, J., and Moon, I. 2017. Key Issues and Challenges on the Liquefied Natural Gas (LNG) Value Chain: A Review from the Process Systems Engineering Point-of-View. *Industrial and Engineering Chemistry Research. 57*. doi:10.1021/acs.iecr.7b03899

Lepădatu, G. 2011. The Importance Of The Cost Information In Making Decisions. *Romanian Economic Business Review, Romanian-American University. 6*. 1. 52-66. doi:10.1080/00207233.2012.677581

Lessner, J. A. 1991. *Traps to avoid in product costing*: American Institute of Certified Public Accountants.

Lewis, C. D. 1982. *Industrial and Business Forecasting Methods: A Practical Guide to Exponential Smoothing and Curve Fitting*: Butterworth Scientific.

Li, Y. 2022. Mathematical Modeling Methods and Their Application in the Analysis of Complex Signal Systems. *Advances in Mathematical Physics 2022*: 1816814. doi:10.1155/2022/1816814

livebunkers. 2022. Types of Fuels used in Ships (Bunker, Bunkering). Retrieved 30 June, 2022 https://www.livebunkers.com/types-fuels-used-ships-bunker-bunkering

Luijk, N. v., Dawson, J., and Cook, A. 2020. Analysis of heavy fuel oil use by ships operating in Canadian Arctic waters from 2010 to 2018. *FACETS. 5*. 1. 304-327. doi:10.1139/facets-2019-0067

Lyridis, D. V. 2022. Spot Charter Rate Forecast for Liquefied Natural Gas Carriers. *Journal of Marine Science and Engineering. 10*. 9. 1270.

Malaret, F. J. 2015. Understanding RAM analysis and typical availability values for LNG plants. Retrieved 8 July, 2022 http://gasprocessingnews.com/features/201504/understanding-ram-analysis-and-typical-availability-values-for-lng-plants.aspx

Mannan, S. 2012. Chapter 39 - Liquefied Natural Gas *Lees' Loss Prevention in the Process Industries (Fourth Edition)*. Ed. S. Mannan. Oxford Butterworth-Heinemann. Chapter: 2492-2506.

Marine Online. 2022. Port Calculator. Retrieved 28 June, 2022 from: https://www.marineonline.com/tools/port-charges-dues-calculator

Meher-Homji, C., Pelagotti, A., and Weyermann, H. 2007. Gas turbines and turbocompressors for LNG service. *Proceedings of the Thirty-sixth Turbomachinery Symposium, 36*. 228. Retrieved 13 May, 2020 from: https : / /hdl .handle .net /1969 .1 /163150

Meira, E., Cyrino Oliveira, F. L., & de Menezes, L. M. 2022. Forecasting natural gas consumption using Bagging and modified regularization techniques. *Energy Economics 106*: 105760. doi:https://doi.org/10.1016/j.eneco.2021.105760

Mentari, D., and Daryanto, W. M. 2018. Capital budgeting model and sensitivity analysis of the project feasibility in vietnam for the period of 2019-2037. *International Journal of Business, Economics and Law. 17*. 2. 21-28. doi:10.3390/en15103510

Mersin, K., Alkan, G., and Mısırlıoğlu, T. 2017. A new method for calculating fuel consumption and displacement of a ship in maritime transport. *Cogent Engineering. 4*. 1. 1415107. doi:10.1080/23311916.2017.1415107

MetGroup. 2021. Shale gas definition, production, and uses. Retrieved 18 June 2022 from: https://group.met.com/en/media/energy-insight/shale-gas

Michelsen, F., Lund, B., & Halvorsen, I. 2010. Selection of optimal, controlled variables for the TEALARC LNG process. *Industrial & Engineering Chemistry Research - Ind Eng Chem RES 49*. doi:10.1021/ie100081j

Mokhatab, S., Mak, J. Y., Valappil, J. V., and Wood, D. A. 2014. *Handbook of Liquefied Natural Gas*. United Kingdom: Elsevier Inc.

Mokhatab, S., and Messersmith, D. 2018. Liquefaction technology selection for baseload LNG plants. Retrieved 2 February 2022 from: https://www.hydrocarbonprocessing.com/magazine/2018/july-2018/bonus-report-lng-technology/liquefaction-technology-selection-for-baseload-lng-plants

Molnar, G. 2022. Economics of Gas Transportation by Pipeline and LNG *The Palgrave Handbook of International Energy Economics*. Eds. M. Hafner and G. Luciani. Cham Springer International Publishing. Chapter: 23-57.

Mousavi, A., Mohammadzadeh, M., & Zare, H. 2022. Developing a System Dynamic Model for Product Life Cycle Management of Generic Pharmaceutical Products: Its Relation with Open Innovation. *Journal of Open Innovation: Technology, Market, and Complexity 8*. 1: 14. doi:https://doi.org/10.3390/joitmc8010014

Nagi, C. A., Dulu Appah, and Chukwu, G. 2016. Comparative Economic Analysis of Gas to Liquid and Liquefied Natural Gas Technologies. *International Journal of Scientific and Engineering Research. 7*. 6. 258-275.

Nasr, G. G., and Connor, N. E. 2014. *Natural gas engineering and safety challenges: Downstream process, analysis, utilization and safety*. Switzerland: Springer International Publishing.

Newnan, D. G., Eschenbach, T. G., and Lavelle, J. P. 2012. *Engineering Economics Analysis* (11 ed.). New York: Oxford University Press.

Nigerian Liquefied Natural Gas. 2019. 2019 Facts and Figures. 100. Retrieved 15 Nov, 2020 from: https://www.nigerialng.com/media/Publications/FACTS%20and%20FIGURES%202019%202nd%20Edition_.pdf

Nigerian Liquefied Natural Gas. 2020. 2020 Facts and Figures. 100. Retrieved 12 January, 2021 from: https://www.nigerialng.com/media/Publications/FACTS%20and%20FIGURES%202020.pdf

NS Energy. 2019. Nigeria LNG Plant Expansion, Bonny Island. Retrieved 12 January, 2021 from: https://www.nsenergybusiness.com/projects/nigeria-lng-plant-expansion-bonny-island/

Numaguchi, H., Satoh, T., Ishida, T., Matsumoto, S., Hino, K., and Iwasaki, T. 2009. Japan's first dual-fuel diesel-electric propulsion liquefied natural gas (LNG) carrier. *Mitsubishi Heavy Industries Technical Review. 46*. 1. 1-4.

Odedairo, B. O., Alaba, E. H., and Edem, I. 2020. A system dynamics model to determine the value of inventory holding cost *Journal of Engineering Studies and Research. 26*. 3. 112-123. doi:https://doi.org/10.29081/jesr.v26i3.213

Odumugbo, C. A. 2010. Natural gas utilisation in Nigeria: Challenges and opportunities. *Journal of Natural Gas Science and Engineering. 2*. 6. 310-316. doi:https://doi.org/10.1016/j.jngse.2010.08.004

Oiltanking. 2022. Heavy Fuel Oil (HFO). Retrieved 16 November, 2022: https://www.oiltanking.com/en/news-info/glossary/heavy-fuel-oil-hfo.html#:~:text=Heavy%20fuel%20oils%20are%20referred,this%20type%20of%20marine%20fuel.

Olujobi, O. J. 2020. Nigeria’s upstream petroleum industry’s contracts: The hurdles and the legal stopgaps. *The Gravitas Review of Business and Property Law. 11*. 4. 17.

Oluwagbemiga, O. E., Olugbenga, O. M., and Zaccheaus, S. A. 2014. Cost Management Practices and Firm’s Performance of Manufacturing Organizations *International Journal of Economics and Finance. 6*. 6. 234-239. doi:DOI: 10.12735/jbm.v3i3p08

Omar, M. N. B. 2016. *Thermodynamic and Economic Evaluation on Existing and Perspective Processes for Liquefaction of Natural Gas in Malaysia.* (Masters), Technische Universität Berlin (TU Berlin), Berlin.

oneclicklca. 2021. Life Cycle Costing in Construction. https://www.oneclicklca.com/building-life-cycle-costing-in-construction/

Pajączek, K., Kostowski, W., and Stanek, W. 2020. Natural gas liquefaction using the high-pressure potential in the gas transmission system. *Energy. 202*. 117726. doi:https://doi.org/10.1016/j.energy.2020.117726

Panneerselvam, R. 2012. *Engineering economics* (11 ed.). New Delhi, India: PHI Learning Private Limited.

Petro Online. 2014. Upstream, midstream and downstream – Understanding the three petroleum markets. Retrieved 9 September, 2022 from: https://www.petro-online.com/news/fuel-for-thought/13/breaking-news/upstream-midstream-and-downstream-ndash-understanding-the-three-petroleum-markets/32165

Petrovich, B., Rogers, H., Hecking Harald, Schulte , S., and Weiser, F. 2017. Future European Gas Transmission Bottlenecks in Differing Supply and Demand Scenarios. Retrieved October 9, 2021 from: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/06/Future-European-Gas-Transmission-Bottlenecks-in-Differing-Supply-and-Demand-Scenarios-NG-119.pdf

Pflueger, B. 2005. How to Calculate Machinery Ownership and Operating Costs from Extension Circulars http://openprairie.sdstate.edu/extension_circ/485

Pinto, J., Sverdrup, H., and Diemer, A. 2019. Integrating life cycle analysis into system dynamics: the case of steel in Europe. *Environmental Systems Research. 8*. doi:10.1186/s40068-019-0144-2

placbillstrack. 2020. Gas flaring (prohibition and punishment) bill, 2020. Retrieved 8 July, 2022 from: https://placbillstrack.org/upload/SB174.pdf

Plomaritou, E. 2014. A review of shipowner's and charterer's obligations in various types of charter. *Journal of Shipping and Ocean Engineering. 4*. 307-321. doi:doi:10.1515/bejeap-2016-0026

Ports.com. 2022. Sea route and distance. Retrieved 28 June, 2022 from: http://ports.com/sea-route/

Rahn, A., Wicke, K., & Wende, G. 2022. Using Discrete-Event Simulation for a Holistic Aircraft Life Cycle Assessment. *Sustainability 14*. 17: 10598.

Raj, R., Ghandehariun, S., Kumar, A., Geng, J., and Linwei, M. 2016a. A techno-economic study of shipping LNG to the Asia-Pacific from Western Canada by LNG carrier. *Journal of Natural Gas Science and Engineering. 34*. 979-992. doi:https://doi.org/10.1016/j.jngse.2016.07.024

Raj, R., Suman, R., Ghandehariun, S., Kumar, A., and Tiwari, M. 2016b. A techno-economic assessment of the liquefied natural gas (LNG) production facilities in Western Canada. *Sustainable Energy Technologies and Assessments. 18*. doi:10.1016/j.seta.2016.10.005

Rasberger, W. 2007. A fresh look at LNG process efficiency. Retrieved 10 October, 2022 https://static.conocophillips.com/files/resources/smid_016_weldonspaperlngindustry.pdf

Recruitment Zilla. 2022. NLNG Salary Structure by Job Title 2022 (Updated). Retrieved 10 August, 2022 from: https://recruitmentzilla.com/nlng-salary-structure

ReliaSoft. 2015. Life Data Analysis Reference. 438. Retrieved Jun. 13, 2019 from: http://www.ReliaSoft.com

Research And Technology Organisation. (2007). *Methods and Models for Life Cycle Costing* (TR-SAS-054). Retrieved 14 June, 2023 from: https://www.sto.nato.int/publications/STO%20Technical%20Reports/RTO-TR-SAS-054/$$TR-SAS-054-ALL.pdf

Richardson, G. P. 2001. System dynamicsSystem dynamics *Encyclopedia of Operations Research and Management Science*. Eds. S. I. Gass and C. M. Harris. New York, NY Springer US. Chapter: 807-810.

Robinson, S. 2022. Exploring the relationship between simulation model accuracy and complexity. *Journal of the Operational Research Society*: 1-20. doi:10.1080/01605682.2022.2122740

Rodrigue, J.-P. 2020. *The geography of transport systems*. New York: Routledge.

Rodrigues, A., and Bowers, J. 1996. System dynamics in project management: a comparative analysis with traditional methods. *System Dynamics Review. 12*. 2. 121-139.

Rogers, H. 2018. The LNG shipping forecast: costs rebounding, outlook uncertain. 18. Retrieved 8 January, 2021 from: https://www.oxfordenergy.org/publications/lng-shipping-forecast-costs-rebounding-outlook-uncertain/

Rowley, W. J. 2017. *The Guide to Energy Arbitrations* (3 ed.). Lancaster Road, London: Law Business Research Limited.

Ruegg, R. T., and Marshall, H. E. 1990. Internal Rate-of-Return (IRR) *Building Economics: Theory and Practice*. Boston, MA Springer US. Chapter: 67-78.

Salem, A., Elgohary, M., and Seediek, I. 2014. Overview of alternative fuels with emphasis on the potential of LNG as future marine fuel. *Proceedings of the Institution of Mechanical Engineers, Part M: Journal of Engineering for the Maritime Environment*. doi:10.1177/1475090214522778

Sarkara, A., Behera, D. K., Kumar, S., and Singha, M. 2012. Life cycle reliability assessment of rukhia gas turbine power plant in Tripura. *International Journal of Current Engineering and Technology. 2*. 1. 184-195.

Sedlaczek, R. (2008). *Boil-off in large- and small-scale LNG chains.* (Diploma Masters), trondheim. Retrieved 23 June 2022 from https://ntnuopen.ntnu.no/ntnu-xmlui/bitstream/handle/11250/2564502/19159_FULLTEXT.pdf?sequence=1

Selcuk, O., Turkoglu, H., Polat, G., and Hajdu, M. 2022. An integrative literature review on the causes of delays in construction projects: evidence from developing countries. *International Journal of Construction Management*. 1-13. doi:10.1080/15623599.2022.2135939

Seo, Y., Jung, J. Y., Han, S., and Kang, K. 2020. Availability estimation of air compression and nitrogen generation systems in lng-fpso depending on design stages. *Applied Sciences. 10*. 8657. doi:10.3390/app10238657

Serpi, A., and Porru, M. 2019. Propulsion Systems. Retrieved 2 May, 2022 from: https://doi.org/10.5772/intechopen.73998 10.5772/intechopen.73998

Seuring, S., Schmidt, W.-P., Ciroth, A., Rebitzer, G., Huppes, G., and Lichtenvort, K. 2008. Modeling for Life Cycle Costing. Chapter: 17-34.

Shakirov, A. 2020. Expert commentary - LNG shipping market: shipping cost slightly declining. Retrieved 02 August, 2022: https://www.gecf.org/events/expert-commentary-lng-shipping-market-shipping-cost-slightly-declining

Shakirov, A. 2021. New trends on the global market of LNG carriers. Retrieved 02 August, 2022 https://www.gecf.org/events/expert-commentary-new-trends-on-the-global-market-of-lng-carriers

Shaw, K. 2022. What is Break-Even Point and How it Can Lead to Success. Retrieved 30 December, 2022 https://simplypayme.com/blog/calculate-break-even-point-bep/

Shim, J., & Cho, H. C. 2019. Forecasting LNG prices with the kernel vector autoregressive model. *Geosystem Engineering 23*: 1-6. doi:10.1080/12269328.2019.1664337

Sievanen, M., and Tornberg, K. 2002. Process-based costing: The best of activity-based costing. *AACE International. Transactions of the Annual Meeting. 15*. CSC151-CSC156.

Simeon, E. D., and Daniel, E. V. 2018. Employee casualisation and cost reduction in Nigeria's oil and gas and banking sectors. *International Journal for Research in Business, Management and Accounting. 4*. 12. 17 - 26.

Singh, K., and Ahuja, I. 2012. Transfusion of Total Quality Management and Total Productive Maintenance: A literature review. *International Journal of Technology. 12*. doi:10.1504/IJTPM.2012.050135

Sinha, R. P., and Wan Nik, W. M. N. 2012. Investigation of propulsion system for large LNG ships. *IOP Conference Series: Materials Science and Engineering. 36*. 012004. doi:10.1088/1757-899x/36/1/012004

SINTEF Industrial Management. 2002. *Offshore Reliability Data Handbook* (4th ed.). Norway: OREDA Participants; Det Norske Veritas.

Škoda, M., Sláviková, G., and Lajčin, D. 2014. The only Correct Calculation Method in Cost Management: From Activity Based Costing Perspective

Journal of Business and Management. 3. 3. 8 -18. doi:DOI: 10.12735/jbm.v3i3p08

Songhurst, B. 2014. *LNG plant cost excalation* (O. I. f. E. Studies Ed.). England: Oxford Institute for Energy Studies.

Songhurst, B. 2018. *LNG Plant Cost Reduction 2014–18* (O. I. f. E. Studies Ed.). England: Oxford Institute for Energy Studies.

Sterman, J. 2000. *Business Dynamics: Systems Thinking and Modeling for a Complex World*: Irwin/McGraw-Hill.

Sterman, J. D. 1989. Misperceptions of feedback in dynamic decision making. *Organizational Behavior and Human Decision Processes. 43*. 3. 301-335. doi:https://doi.org/10.1016/0749-5978(89)90041-1

Steuer, C. 2019. *Outlook for competitive LNG supply* (O. I. f. E. Studies Ed.). England: Oxford Institute for Energy Studies.

Styliadis, T., and Koliousis, I. 2017. LNG operations: Safety issues and procedures. 24. Retrieved 03 March, 2022 from: https://businessdocbox.com/Green_Solutions/77800372-Lng-operations-safety-issues-and-procedures-styliadis-theodore-koliousis-ioannis-deparment-of-maritime-studies-university-of-piraeus.html

Tagliaferri, C., Clift, R., Lettieri, P., and Chapman, C. 2017. Liquefied natural gas for the UK: a life cycle assessment. *The International Journal of Life Cycle Assessment. 22*. 12. 1944-1956. doi:10.1007/s11367-017-1285-z

Tamura, I., Tanaka, T., Kagajo, T., Kuwabara, S., Yoshioka, T., Nagata, T., . . . Ishitani, H. 2001. Life cycle CO 2 analysis of LNG and city gas. *Applied Energy - APPL ENERG. 68*. 301-319. doi:10.1016/S0306-2619(00)00062-3

Tarver, E. 2022. How do you find the break-even point using a payback period? Retrieved 13 December, 2022 from: https://www.investopedia.com/ask/answers/072215/how-do-you-find-breakeven-point-using-payback-period.asp#

Thomas, S., and Dawe, R. 2003. Review of Ways to Transport Natural Gas Energy From Countries Which Do Not Need the Gas for Domestic Use. *Energy. 28*. 1461-1477. doi:10.1016/S0360-5442(03)00124-5

Thoms, B. 2011. A Dynamic Social Feedback System to Support Learning and Social Interaction in Higher Education. *TLT*. *4*. 340-352. doi:10.1109/TLT.2011.9

Thomson, H., Corbett, J. J., and Winebrake, J. J. 2015. Natural gas as a marine fuel. *Energy Policy*. *87*. 153-167. doi:https://doi.org/10.1016/j.enpol.2015.08.027

Thornton, G. 2019. U.S. LNG offers long-term investment returns. Retrieved 16 November, 2022 from https://www.grantthornton.com/library/articles/energy/2019/LNG-offers-long-term-investment-returns.aspx

Tractebel Engineering, S. A. 2015. Mini / Micro LNG for commercialization of small volumes of associated gas. Retrieved 2 February 2022 https://openknowledge.worldbank.org/bitstream/handle/10986/25919/112131.pdf?sequence=4

transportgeography. 2017. Fuel consumption by containership sizeand speed. Retrieved 24 March, 2022 https://transportgeography.org/contents/chapter4/transportation-and-energy/fuel-consumption-containerships/

Troelsen, T. 2006. Dynamic Costing. Retrieved 25/01/2020 from Troels Troelsen andVentures Publishing https://bookboon.com/en/dynamic-costing-1-ebook

Tu, H. 2019. Options and Evaluations on Propulsion Systems of LNG Carriers. Chapter.

Uhler, A. D., Stout, S. A., Douglas, G. S., Healey, E. M., and Emsbo-Mattingly, S. D. 2016. 13 - Chemical character of marine heavy fuel oils and lubricants *Standard Handbook Oil Spill Environmental Forensics (Second Edition)*. Eds. S. A. Stout and Z. Wang. Boston Academic Press. Chapter: 641-683.

UK Defence Club. 2021. LNG charters common issues. Retrieved 30 June, 2022 https://www.ukdefence.com/fileadmin/uploads/uk-defence/Documents/UKDC-LNG-Charterparties-2021-WEB2.pdf

US Department of Energy. 2020. Liquefied natural gas value chain. Retrieved 29 May 2022, from Gulf Publushing Holdings LLC https://www.energy.gov/sites/default/files/2020/10/f79/LNG%20Value%20Chain%20Fact%20Sheet_1.pdf8

US Energy Information Aministration [EIA]. 2022. Natural gas explained: Where our natural gas comes from. Retrieved 29 November 2022 eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php#:~:text=Natural%20gas%20is%20produced%20from,U.S.%20total%20natural%20gas%20consumption.

USDA, and USEA. 2016. Understanding Natural Gas and LNG Options. (DE-FE0024160.). Retrieved 20 January, 2020 https://www.energy.gov/sites/prod/files/2016/12/f34/Understanding%20Natural%20Gas%20and%20LNG%20Options.pdf

Vandoorne, R., & Gräbe, P. J. 2018. Stochastic rail life cycle cost maintenance modelling using Monte Carlo simulation. *Proceedings of the Institution of Mechanical Engineers, Part F: Journal of Rail and Rapid Transit 232*. 4: 1240-1251. doi:10.1177/0954409717714645

Vasili, M., Hong, T. S., Ismail, N., and vasili, M. 2011. *Maintenance Optimisation Models: A Review and Analysis.* Paper presented at the Proceedings of the 2011 International Conference on Industrial Engineering and Operations management, Kuala Lumpur, Malaysia, 22-24 January, 2011.

Veskovic, D., Beard, J., Roberts, M., and Graham, D. 2022. Decarbonize LNG liquefaction with pre-combustion CO2 capture technology. Gas Processing and LNG. Retrieved 26 December 2022 https://www.airproducts.com/-/media/airproducts/files/en/lng/decarbonize-lng-liquefaction-reprint-gas-processing-and-lng-jun2022.pdf?la=enandhash=C7ABA4227B1404A51E48282A44B9544D

Walia, D., Huria, J., and Cordero, I. 2010. Equipment maintenance and repair. *Community eye health. 23*. 73. 26-29.

Wang, N., Chang, Y.-C., & El-Sheikh, A. 2012. Monte Carlo simulation approach to life cycle cost management. *Structure and Infrastructure Engineering 8*: 739-746. doi:10.1080/15732479.2010.481304

White, J. A., Grasman, K. S., Case, K. E., Needy, K. L., and Pratt, D. B. 2020. *Fundamentals of engineering economic analysis* (2 ed.). USA: John Wiley and Sons, Inc.

wikipedia. 2022. List of countries by natural gas proven reserves. Retrieved 16 November, 2022 https://en.wikipedia.org/wiki/List_of_countries_by_natural_gas_proven_reserves

Woodward, D. G. 1997. Life cycle costing—Theory, information acquisition and application. *International Journal of Project Management. 15*. 6. 335-344. doi:https://doi.org/10.1016/S0263-7863(96)00089-0

World Bank. 2022. Commodity price data (The pink sheet). Retrieved 17 June, 2022 https://thedocs.worldbank.org/en/doc/5d903e848db1d1b83e0ec8f744e55570-0350012021/related/CMO-Historical-Data-Annual.xlsx

Xie, Y. 2011. Values and limitations of statistical models. *Res Soc Stratif Mobil 29*. 3: 343-349. doi:10.1016/j.rssm.2011.04.001

Xu, J., Testa, D., and Mukherjee, P. K. 2015. The Use of LNG as a Marine Fuel: The International Regulatory Framework. *Ocean Development and International Law. 46*. 3. 225-240. doi:10.1080/00908320.2015.1054744

Xu, X., Chen, J. L.-Q., and Xie, X. Q. 2009. Framework of a Product Lifecycle Costing System. *Journal of Computing and Information Science in Engineering 6*. 1. 69-77.

Yu-Lee, R. T. 2002. *Explicit Cost Dynamics: An Alternative to Activity-based Costing*. USA: John Wiley and Sons.

Zhang, J., Meerman, H., Benders, R., and Faaij, A. 2020. Comprehensive review of current natural gas liquefaction processes on technical and economic performance. *Applied Thermal Engineering. 166*. 114736. doi:https://doi.org/10.1016/j.applthermaleng.2019.114736

APPENDIX A

SOURCE CODE FOR THE SYSTEM DYNAMICS BASED LIQUEFIED NATURAL GAS LIFE CYCLE COSTING (SD-LNG-LCC) MODEL

Funded Budget Inflow
IF THEN ELSE(Time=0, CAPEX Budget/"Budget Availability Factor (BAF)",IF THEN ELSE (MODULO(POP,12*"Mnth-Desired Time Window Converter")=0,Annual OPEX Budget/"Budget Availability Factor (BAF)" ,0))

CAPEX Fund (CF)
IF THEN ELSE(Total CF Fund<=0,IF THEN ELSE(CF Delay Factor=1,"CAPEX Fund (CF)",0) ,0)

OPEX Fund InFlow
IF THEN ELSE(Total CF Fund>0,IF THEN ELSE(MODULO(POP,12*"Mnth-Desired Time Window Converter")=0,IF THEN ELSE(Funded Budget >= (Funded Budget InFlow*"Budget Implementation Level (BIL)")/"OPEX Fund Availability Factor (FAF)",(Funded Budget InFlow*"Budget Implementation Level (BIL)")/"OPEX Fund Availability Factor (FAF)" ,Funded Budget/"OPEX Fund Availability Factor (FAF)"),0) ,0)

CAPEX Budget
(Bulk Materials Cost+Construction Cost+Engineering and Proj Mgt Cost+Equipment Cost+Owners Cost)

Owners Total Cost
"Owners Cost Per Unit Plant Design Capacity (PDC)"*"Greenfield Plant Design Capacity (GPDC)"

Total Bulk Materials Cost
(Bulk Material Cost Per Unit GPDC*"Greenfield Plant Design Capacity (GPDC)")+(Bulk Material Cost Per Unit BPDC*"Brownfield Plant Design Capacity (BPDC)")

Total Construction Cost
(Construction Cost Per Unit GPDC*"Greenfield Plant Design Capacity (GPDC)")+(Construction Cost Per Unit BPDC*"Brownfield Plant Design Capacity (BPDC)")

Total Engineering and Proj Mgt Cost
Engineering and Proj Mgt Cost Per Unit PDC*"Greenfield Plant Design Capacity (GPDC)"

Total Equipment Cost
(Equipment Cost Per Unit GPDC*"Greenfield Plant Design Capacity (GPDC)")+(Equipment Unit Cost Per Unit BPDC*"Brownfield Plant Design Capacity (BPDC)")

Total OPEX Fund
OPEX Fund Inflow-Equipment Mtce Fund Inflow-Feed Gas Fund Inflow-Fuel Gas Fund Inflow-Labour Fund Inflow-OOC Fund Inflow

Equipment Mtce Fund Inflow
IF THEN ELSE("Total OPEX Fund (With Feed Cost consideration)">0,IF THEN ELSE(Total CF Fund>0,Equipment Mtce FF*Equipment Mtce FIL*"Total OPEX Fund (With Feed Cost consideration)" *"OPEX Fund Availability Factor (FAF)",0) ,0)

Feed Gas Fund Inflow
IF THEN ELSE("Total OPEX Fund (With Feed Cost consideration)">0, IF THEN ELSE(Total CF Fund>0,Feed Gas FF*Feed Gas FIL*"Total OPEX Fund (With Feed Cost consideration)" *OPEX FAF ,0),0)

Fuel Gas Fund Inflow
IF THEN ELSE("Total OPEX Fund (With Feed Cost consideration)">0,IF THEN ELSE(Total CF Fund>0,Fuel Gas BF*Fuel Gas FIL*"Total OPEX Fund (With Feed Cost consideration)" *OPEX FAF ,0) ,0)

Labour Fund Inflow
IF THEN ELSE("Total OPEX Fund (With Feed Cost consideration)">0,IF THEN ELSE(Total CF Fund>0,"Labour Funding Factor (FF)"*Labour FIL*"Total OPEX Fund (With Feed Cost consideration)" *OPEX FAF ,0) ,0)

OOC Fund Inflow
IF THEN ELSE("Total OPEX Fund (With Feed Cost consideration)">0,IF THEN ELSE(Total CF Fund>0,OOC FF*OOC FIL*"Total OPEX Fund (With Feed Cost consideration)" *OPEX FAF ,0) ,0)

Equipment Mtce FF
IF THEN ELSE(Equipment Mtce OPEX Factor>0, Equipment Mtce OPEX Factor,IF THEN ELSE("LNG Stock Price (Gas)">0,16.51/100 ,3.08/100))

Feed Gas FF
IF THEN ELSE(Feed Gas OPEX Factor>0, Feed Gas OPEX Factor, IF THEN ELSE("LNG Stock Price (Gas)">0,15.19/100 ,84.22/100))

Fuel Gas FF
IF THEN ELSE(Fuel gas OPEX factor>0, Fuel gas OPEX factor,IF THEN ELSE("LNG Stock Price (Gas)">0,50.22/100 ,9.34/100))

Labour Funding Factor (FF)
IF THEN ELSE(Total Labour OPEX Factor>0, Total Labour OPEX Factor,IF THEN ELSE("LNG Stock Price (Gas)">0,6.83/100 ,1.27/100))

OOC FF
IF THEN ELSE (OOC OPEX factor>0, OOC OPEX factor,IF THEN ELSE("LNG Stock Price (Gas)">0,11.25/100 ,2.09/100))

Equipment Mtce Fund

Equipment Mtce Fund Inflow-Equipment Mtce Expenditure Flow-Unused EMF Outflow

Feed Gas Fund
Feed Gas Fund Inflow-Feed Gas Expenses Flow-Unused FGF Outflow

Fuel Gas Fund
Fuel Gas Fund Inflow-Fuel Gas Expenditure Flow-Unused FuGF Outflow

Labour Fund
Labour Fund Inflow-Labour Expenditure Flow-Unused LF Outflow

Overhead/Other (OOC) Fund
OOC Fund Inflow-OOC Expenditure Flow-Unused OOC Fund Outflow

Equipment Mtce Expenditure Flow
IF THEN ELSE(Equipment Mtce Fund>0,IF THEN ELSE(Equipment Mtce Fund>=(Periodic Maintenance Cost*(1+Equipment Mtce FLF)),(Periodic Maintenance Cost*(1+Equipment Mtce FLF)),Equipment Mtce Fund/"OPEX Fund Availability Factor (FAF)") ,0)

Feed Gas Expenses Flow
IF THEN ELSE("Feed Gas Fund (FGF)">0, IF THEN ELSE("Feed Gas Fund (FGF)" >=(Periodic Gas Usage Cost*(1+Feed Gas FLF)),((Periodic Gas Usage Cost*(1+Feed Gas FLF)))/OPEX FAF,"Feed Gas Fund (FGF)"/OPEX FAF),0)

Fuel Gas Expenditure Flow
IF THEN ELSE(Fuel Gas Fund>0,IF THEN ELSE(Fuel Gas Fund>=(Periodic Energy Cost*(1+Fuel Gas FLF)),Periodic Energy Cost*(1+Fuel Gas FLF),Fuel Gas Fund/OPEX FAF) ,0)

Labour Expenditure Flow
IF THEN ELSE(Labour Fund>0,IF THEN ELSE(Labour Fund>=(Periodic Labour Cost*(1+"Labour Fund Leakage Factor (FLF)")),(Periodic Labour Cost*(1+"Labour Fund Leakage Factor (FLF)")),Labour Fund/OPEX FAF) ,0)

OOC Expenditure Flow
IF THEN ELSE("Overhead/Other (OOC) Fund">0,IF THEN ELSE("Overhead/Other (OOC) Fund">= (Periodic OOC cost*(1+OOC FLF)),(Periodic OOC cost*(1+OOC FLF)),"Overhead/Other (OOC) Fund"/OPEX FAF) ,0)

Unused EMF Outflow
IF THEN ELSE(Equipment Mtce Fund Inflow>0,UEMFO Factor*"Equipment Mtce Fund (EMF)" ,0)

Unused FGF Outflow
IF THEN ELSE(Feed Gas Fund Inflow>0,UFGFO Factor*"Feed Gas Fund (FGF)" ,0)

Unused FuGF Outflow
IF THEN ELSE(Fuel Gas Fund Inflow>0,UFuGFO Factor*"Fuel Gas Fund (FuGF)" ,0)

Unused LF Outflow

IF THEN ELSE(Labour Fund Inflow>0,ULFO Factor*"Labour Fund (LF)" ,0)

Unused OOC Fund Outflow
IF THEN ELSE(OOC Fund Inflow>0,UOOCFO Factor*"Overhead/Other (OOC) Fund",0)

Total Equipment Mtce Expenses
Equipment Mtce Expenditure Flow

Total Feed Gas Expenses
Feed Gas Expenses Flow

Total Fuel Gas Expenses
Fuel Gas Expenditure Flow

Total Labour Expenses
Labour Expenditure Flow

Total OOC Expenses
OOC Expenditure Flow

##
##############**The Production Operations Sector**

Plant Operation Window (POW)
-POW Wind Up Rate (Lower Boundary condition: Plant Useful Life)

POW Wind Up Rate
IF THEN ELSE(Total CF Fund>0,IF THEN ELSE(("Equipment Mtce Fund (EMF)"+"Feed Gas Fund (FGF)"+"Fuel Gas Fund (FuGF)"+"Labour Fund (LF)"+"Overhead/Other (OOC) Fund")>0 :AND: "Plant Operation Window (POW)">0 ,TIME STEP ,IF THEN ELSE("Plant Operation Window (POW)"<Plant Useful Life :AND: "Plant Operation Window (POW)">0,TIME STEP ,0)) ,0)

NG Stock
-NG Stock Depletion Rate

NG Stock Depletion Rate
IF THEN ELSE(NG Stock>0,IF THEN ELSE((NG Stock/Plant Unit Operation Window)>(NG Stock Joint Use Factor*Feed Gas Rate),NG Stock Joint Use Factor*Feed Gas Rate ,(NG Stock/Plant Unit Operation Window)) ,0)

NG Available For Production
Feed Gas Rate-NG Utilisation Rate

Feed Gas Rate
IF THEN ELSE(Feed Gas Accessibility Delay=0, IF THEN ELSE((NG Available For Production*Feed Gas Supply Frequency)<((Gas Delivery Volume*Feed Gas Supply Frequency)*(1+"Natural Gas (NG) Plant Capacity Factor")), IF THEN ELSE(((NG Available For Production*Feed Gas Supply Frequency)+(Gas Delivery Volume*Feed Gas Supply Frequency))<=((Gas Delivery Volume*Feed Gas Supply Frequency)*(1+"Natural

Gas (NG) Plant Capacity Factor")),Gas Delivery Volume,((Gas Delivery Volume*Feed Gas Supply Frequency)*(1+"Natural Gas (NG) Plant Capacity Factor"))-(NG Available For Production*Feed Gas Supply Frequency)),0) ,0)

NG Utilisation Rate
LNG Production Start Rate

Gas Delivery Volume
IF THEN ELSE("Feed Gas Fund (FGF)">0,IF THEN ELSE(NG Stock>0,IF THEN ELSE(NG Stock>=Desired Gas Usage Volume,Desired Gas Usage Volume*Gas Delivery Capability Factor,NG Stock*Gas Delivery Capability Factor),0) ,0)

Gas Delivery Capability Factor
1

Desired Gas Usage Volume
IF THEN ELSE(("PPLR (Gas equivalent)"/"Natural Gas (NG) Conversion Factor")<=(Desired Prod Start Volume),"PPLR (Gas equivalent)"/"Natural Gas (NG) Conversion Factor" ,IF THEN ELSE((Desired Prod Start Volume)<=("PPLR (Gas equivalent)"/"Natural Gas (NG) Conversion Factor"),Desired Prod Start Volume ,0))

"PPLR (Gas equivalent)"
"Perceived Plant LNG Requirement (PPLR)"*"M^3 Gas per M^3 LNG Converter"

"Perceived Plant LNG Requirement (PPLR)"
IF THEN ELSE(((Customer Order)/"Natural Gas (NG) Conversion Factor")>="Periodic Plant Capacity (LNG)","Periodic Plant Capacity (LNG)" ,Customer Order)

Customer Order
"Periodic Plant Capacity (LNG)"*Customer Order Fraction

"Periodic Plant Capacity (LNG)"
IF THEN ELSE(TA Mtce Action=0,("Desired LNG Stock (M^3)")/(Plant Useful Life) ,0)

Accumulated Orders (CO)
Customer Order Rate-Order Release Rate

CO Rate
IF THEN ELSE(Order Receipt Policy on TA Mtce=1,"Customer Order (CO)",IF THEN ELSE(TA Mtce Action
=0,"Customer Order (CO)",0))

Customer Order
IF THEN ELSE(("Periodic Plant Capacity (LNG)"*Customer Order Fraction)>"Periodic Plant Capacity (LNG)","Periodic Plant Capacity (LNG)"*"Natural Gas (NG) Conversion Factor","Periodic Plant Capacity (LNG)"*Customer Order Fraction*"Natural Gas (NG) Conversion Factor")

Production Order (PO) rate

IF THEN ELSE(TA Mtce Action=0,IF THEN ELSE((Accumulated Cos*PO Frequency)>(("Periodic Plant Capacity (LNG)"*"Natural Gas (NG) Conversion Factor")*PO Frequency),("Periodic Plant Capacity (LNG)"*"Natural Gas (NG) Conversion Factor")*PO Frequency,(Accumulated Cos*PO Frequency)) ,0)

Order Release Rate
IF THEN ELSE(Target Delivery Delay=1,IF THEN ELSE(Accumulated Orders>0 :AND:Produced LNG>0,IF THEN ELSE(Accumulated Orders>=Produced LNG,Produced LNG,Accumulated Orders) ,0) ,0)

##
###########

#Production Workforce Management Sub-Sector

Active Production Personnel
Integ(Active PP Inflow-Active Production Personnel Outflow-Active PP Firing Rate)
Initial Value (0)

Active PP Inflow
IF THEN ELSE(System Availability Status=1,IF THEN ELSE(Required Prod Workforce>0,IF THEN ELSE((Required Prod Workforce)<=(Active Production Personnel*Active PP Assignment Factor),0 ,IF THEN ELSE(Required Prod Workforce-(Active Production Personnel*Active PP Assignment Factor)<=(Inactive Production Personnel*Active PP Assignment Factor),Required Prod Workforce-(Active Production Personnel*Active PP Assignment Factor) ,(Inactive Production Personnel*Active PP Assignment Factor))),IF THEN ELSE(Constrained Labour for Production<=(Active Production Personnel*Active PP Assignment Factor)
,0 ,IF THEN ELSE((Constrained Labour for Production-(Active Production Personnel*Active PP Assignment Factor))<=(Inactive Production Personnel*Active PP Assignment Factor),(Constrained Labour for Production-(Active Production Personnel*Active PP Assignment Factor)) ,(Inactive Production Personnel*Active PP Assignment Factor)))),0)

Active PP Outflow
IF THEN ELSE(System Availability Status=1,IF THEN ELSE(Required Prod Workforce Backlog>0,IF THEN ELSE(Required Prod Workforce Backlog>=(Active Production Personnel*Active PP Assignment Termination Factor),0 ,(Active Production Personnel*Active PP Assignment Termination Factor)-Required Prod Workforce Backlog),IF THEN ELSE(Constrained Labour for Production>=(Active Production Personnel*Active PP Assignment Termination Factor),0 ,(Active Production Personnel*Active PP Assignment Termination Factor)-Constrained Labour for Production)),(Active Production Personnel*Active PP Assignment Termination Factor))

Recruited Production Workforce
IF THEN ELSE(Production Recruitment Delay="Recruitment (Rec.) Delay Period",IF THEN ELSE(Production Personnel<("Max. Prod Workforce No. Allowable"),IF THEN ELSE((Production Personnel+"Prod. Workforce for Recruitment")>=("Max. Prod

Workforce No. Allowable"),("Max. Prod Workforce No. Allowable")-Production Personnel ,"Prod. Workforce for Recruitment") ,0) ,0)

Max. Prod Workforce No. Allowable
integer(LNG Desired Workforce*(1+Desired Workforce Upper Tolerance))

Active PP Firing Rate
IF THEN ELSE(Non Economic Related Firing<=Active Production Personnel,Non Economic Related Firing*Active PP Firing Frequency ,Active Production Personnel*Active PP Firing Frequency)

PP Firing Rate
IF THEN ELSE(POP>0,IF THEN ELSE(System Availability Status=0,IF THEN ELSE((Total Production Personnel*Inactive PP Firing Frequency)>"Min Prod Workforce No. Allowable",(Total Production Personnel*Inactive PP Firing Frequency)-"Min Prod Workforce No. Allowable" ,0),IF THEN ELSE(Production Workforce Recruitment In Progress=1,0 ,IF THEN ELSE(No Production Workforce Recruitment In Progress=1,IF THEN ELSE((Total Production Personnel*Inactive PP Firing Frequency)>"Min Prod Workforce No. Allowable", IF THEN ELSE(Inactive Production Personnel>0,IF THEN ELSE((((Total Production Personnel-Active Production Personnel)*Inactive PP Firing Frequency)-Active PP Inflow)>=((Inactive Production Personnel*Inactive PP Firing Frequency)-Active PP Inflow), IF THEN ELSE(((Inactive Production Personnel*Inactive PP Firing Frequency)-Active PP Inflow)>="Min Prod Workforce No. Allowable",((Inactive Production Personnel*Inactive PP Firing Frequency)-Active PP Inflow)-"Min Prod Workforce No. Allowable",((Inactive Production Personnel*Inactive PP Firing Frequency)-Active PP Inflow)) ,0),0),0),0))),0)

Prod. Workforce for Recruitment
Integ(Prod Workforce Recruitment Rate-Recruited PP Release Rate)
Initial value(0)

Prod Workforce Recruitment Rate
IF THEN ELSE(Production Recruitment Delay=0,IF THEN ELSE(Production Workforce Recruitment Request>0,Production Workforce Recruitment Request*Operations Resource Availability Factor,0) ,0)

Recruited PP Release Rate
IF THEN ELSE(Production Recruitment Delay="Recruitment (Rec.) Delay Period":AND:System Availability Status=1,"Prod. Workforce for Recruitment",0)

Recruited PP Release Rate
IF THEN ELSE(Production Recruitment Delay="Recruitment (Rec.) Delay Period":AND:System Availability Status=1,"Prod. Workforce for Recruitment"*Recruited PP Release Frequency,0)

Constrained Workforce for Production
IF THEN ELSE(Workforce Estimated for Production>=0,IF THEN ELSE(Workforce Estimated for Production<=Labour From Budget Capability,IF THEN ELSE(Workforce Estimated for Production<="Max. Prod Workforce No. Allowable",Workforce Estimated

for Production,"Max. Prod Workforce No. Allowable") ,IF THEN ELSE(Labour From Budget Capability<="Max. Prod Workforce No. Allowable",Labour From Budget Capability ,"Max. Prod Workforce No. Allowable")),0)

Labour From Budget Capability
IF THEN ELSE((((Production Operators Fund)/Operations Labour Wage Rate)-(integer((Production Operators Fund)/Operations Labour Wage Rate)))>=0.5 ,integer ((Production Operators Fund)/Operations Labour Wage Rate)+1 ,integer((Production Operators Fund)/Operations Labour Wage Rate))

Workforce Perceived for Production
IF THEN ELSE (Perceived Production Workforce Capability>0,IF THEN ELSE(NG Available For Production<"Periodic Plant Capacity (Gas Equivalent)",NG Available For Production/(Perceived Production Workforce Capability),"Periodic Plant Capacity (Gas Equivalent)"/(Perceived Production Workforce Capability)) ,0)

Perceived Production Workforce Capability
Expected Production Workforce Capability*(Operations Productivity/Facility Location Factor)

##
##############**The Maintenance Operations Sector**

**#$$$
$$$$$$**

 # Equipment Maintenance Subsector

CT1 Degradation Level
Integ(CT1 Degradation Rate-CT1 Degradation Reduction Rate)
Initial Value(0)

CT1 Degradation Rate
IF THEN ELSE(POP>0 :AND: POP<=Plant Useful Life, IF THEN ELSE(System Failure=0 ,TIME STEP,0) ,0)

CT1 Degradation Reduction Rate
IF THEN ELSE(CT1 Mtce Process>0, IF THEN ELSE(CT1 Degradation Level>0 ,CT1 Degradation Level ,0),0)

CT1 Mtce Process
Integ(CT1 Mtce Rate-CT1 Restart Rate)

CT1 Mtce Rate
IF THEN ELSE("CT1 Manpower and Material Availability"=1,IF THEN ELSE(CT1 Restart Rate<=0,IF THEN ELSE(CT1 Mtce Action=1,TIME STEP ,0) ,0) ,0)

CT1 Restart Rate
IF THEN ELSE(CT1 Mtce Process=integer(CT1 Intervention Period):AND:CT1 Mtce Process<>0,CT1 Mtce Process ,0)

CT1 Manpower and Material Availability
Max("CT1 CM-PM MMA",CT1 TA MMA)

CT1 CM-PM MMA
IF THEN ELSE("Spare Availbility for CM/PM">0,IF THEN ELSE(CT1 Mtce Manpower Availability=1 ,1 ,0),0)

CT1 TA MMA
IF THEN ELSE(Spare Availbility for TA>0,IF THEN ELSE(CT1 Mtce Manpower Availability=1 ,1 ,0),0)

CT1 Mtce Action
Max(IF THEN ELSE((CT1 Unplanned Mtce Action=1 :OR:CT1 Mtce Mode=3),1 ,0),Max(IF THEN ELSE((CT1 TA Mtce Action=1 :OR:CT1 Mtce Mode=1),1 ,0),IF THEN ELSE((CT1 Prev Mtce Action=1 :OR:CT1 Mtce Mode=2) ,1 ,0)))

CT1 Unplanned Failure (UF)
IF THEN ELSE((CT1 Failure Probability>="CT1 Random Failure Prob." :AND: "CT1 Random Failure Prob.">0),1 ,0)

CT1 Prev Mtce Action
IF THEN ELSE("CT1 Prev Mtce (PM) Action Signal"=1 :AND:"CT1 CM-PM MMA"=1,IF THEN ELSE(Time to TA Mtce>0,IF THEN ELSE((CT1 PM Intervention Period)<Time to TA Mtce,1 ,0) ,0) ,0)

CT1 Unplanned Mtce Action
IF THEN ELSE(("CT1 Unplanned Failure (UF)"=1 :OR: CT1 UF Signal>0):AND:"CT1 CM-PM MMA"=1 ,IF THEN ELSE (Time to TA Mtce>0,IF THEN ELSE((CT1 CM Intervention Period)<Time to TA Mtce,1 ,0) ,0) ,0)

CT1 Intervention Period
IF THEN ELSE(CT1 Mtce Mode=1,"CT1 T.A. Mtce Intervention period" ,IF THEN ELSE(CT1 Mtce Mode=2,CT1 PM Intervention Period ,IF THEN ELSE(CT1 Mtce Mode=3,CT1 CM Intervention Period ,0)))

CT1 CM Intervention Period
IF THEN ELSE ((("CT1 CM/PM Time"/("CM Log. Factor"*CM Efficiency*Mtce Effectiveness))-integer(("CT1 CM/PM Time"/("CM Log. Factor"*CM Efficiency*Mtce Effectiveness))))>=0.5,integer(("CT1 CM/PM Time"/("CM Log. Factor"*CM Efficiency*Mtce Effectiveness)))+1 ,integer(("CT1 CM/PM Time"/("CM Log. Factor"*CM Efficiency*Mtce Effectiveness))))

CT1 PM Personnel Pre-Request
IF THEN ELSE(PM Threshold Period for E(k)-CT1 Degradation Level=CT1 PM Request Window,IF THEN ELSE(Time to TA Mtce>0,IF THEN ELSE((CT1 Time to PM+CT1 PM Intervention Period)<Time to TA Mtce,1 ,0) ,0),0)

CT1 Downtime
IF THEN ELSE(CT1 UF=1 :OR: CT1 Mtce Rate=1 :OR: (CT1 Mtce Rate=0 :AND: CT1 Mtce Action=1:AND:"CT1 Manpower and Material Availability"=0),TIME STEP ,0)

CT1 Time to PM
"PM Threshold Period for E(k)"-"E(k) Degradation Level"

CT1 Failure Probability
1-(exp(-1*((("E(k) Degradation Level")/"E(k) Weibull Eta")^"E(k) Weibull Beta")))

CT1 Prev Mtce (PM) Action Signal
IF THEN ELSE("E(k) Time to PM" <=0 :AND: "E(k) UF Signal"=0,1 ,0)

CT1 CM/PM Mtce Workforce Required
"CT1 CM/PM Personnel In"-"CT1 CM/PM Personnel Out"

CT1 CM/PM Periodic Mtce Workforce Required
IF THEN ELSE(POP>0 :AND:POP<=Plant Useful Life,IF THEN ELSE(CT1 Manpower Mode Requested =1,IF THEN ELSE("CT1 CM/PM Mtce Workforce Required">0,0 ,IF THEN ELSE((("CT1 CM/PM Mtce Manhour Required"/"CT1 CM/PM Time")-integer("CT1 CM/PM Mtce Manhour Required"/"CT1 CM/PM Time"))>=0.5,integer("CT1 CM/PM Mtce Manhour Required"/"CT1 CM/PM Time")+1,integer("CT1 CM/PM Mtce Manhour Required"/"CT1 CM/PM Time"))) ,IF THEN ELSE(CT1 Manpower Mode Requested=3,IF THEN ELSE("CT1 CM/PM Mtce Workforce Required">0,0 ,IF THEN ELSE((("CT1 CM/PM Mtce Manhour Required"/"CT1 CM/PM Time")-integer("CT1 CM/PM Mtce Manhour Required"/"CT1 CM/PM Time"))>=0.5,integer("CT1 CM/PM Mtce Manhour Required"/"CT1 CM/PM Time")+1,integer("CT1 CM/PM Mtce Manhour Required"/"CT1 CM/PM Time"))) ,0)) ,0)

CT1 CM/PM Required Periodic Mtce Workforce Met (RPMWM)
IF THEN ELSE("CT1 CM/PM Personnel Request Out">0,"CT1 CM/PM Mtce Workforce Required"/RPMWM Frequency,0)

CT1 TA Periodic Mtce Workforce Required
IF THEN ELSE(POP>0 :AND:POP<=Plant Useful Life :AND:CT1 TA Request In=1,IF THEN ELSE(CT1 TA Mtce Workforce Required>0,0 ,IF THEN ELSE((((CT1 TA Mtce Manhour Required*CT1 TA Required Mtce Workforce Frequency)/CT1 Actual TA Mtce Duration)-integer((CT1 TA Mtce Manhour Required*CT1 TA Required Mtce Workforce Frequency)/CT1 Actual TA Mtce Duration))>=0.5,integer((CT1 TA Mtce Manhour Required*CT1 TA Required Mtce Workforce Frequency)/CT1 Actual TA Mtce Duration)+1, integer((CT1 TA Mtce Manhour Required*CT1 TA Required Mtce Workforce Frequency)/CT1 Actual TA Mtce Duration))) ,0)

CT1 TA Mtce Workforce Required
CT1 TA Periodic Mtce Workforce Required-CT1 TA Required Periodic Mtce Workforce Met

CT1 TA Periodic Mtce Workforce Required
IF THEN ELSE(POP>0 :AND:POP<=Plant Useful Life :AND:CT1 TA Request In=1,IF THEN ELSE(CT1 TA Mtce Workforce Required>0,0 ,IF THEN ELSE((((CT1 TA Mtce Manhour Required*CT1 TA Required Mtce Workforce Frequency)/CT1 Actual TA Mtce Duration)-integer((CT1 TA Mtce Manhour Required*CT1 TA Required Mtce Workforce Frequency)/CT1 Actual TA Mtce Duration))>=0.5,integer((CT1 TA Mtce Manhour

Required*CT1 TA Required Mtce Workforce Frequency)/CT1 Actual TA Mtce Duration)+1, integer((CT1 TA Mtce Manhour Required*CT1 TA Required Mtce Workforce Frequency)/CT1 Actual TA Mtce Duration))) ,0)

CT1 TA Required Periodic Mtce Workforce Met
IF THEN ELSE(CT1 Periodic Mtce Workers Request Met (TA)>0,CT1 TA Mtce Workforce Required*"CT1 TA Required Periodic Mtce Workforce Met (RPMWM)" ,0)

CT1 No. of. Mtce. Workers Request
IF THEN ELSE(CT1 Request Dun=1,CT1 TA Mtce Workforce Required ,0)+IF THEN ELSE(CT1 Request Dun=2 :OR:CT1 Request Dun=3,"CT1 CM/PM Mtce Workforce Required" ,0)

CT1 RD In
CT1 Manpower Mode Requested

CT1 Manpower Mode Requested
IF THEN ELSE(CT1 UF Personnel Request=1,3 ,IF THEN ELSE("CT1 CM/PM Personnel Request"=1 :AND:CT1 Time to PM=3,2 ,IF THEN ELSE(CT1 TA Personnel Request=1 :AND:Time to TA Mtce=3,1 ,IF THEN ELSE(System CM Intervention Time >= Time to TA Mtce :AND: System CM Intervention Time>0,1 ,0))))

CT1 Request Dun
"E(k) Workers Request Signal Start"-"E(k) Mtce Workers Request Signal End"

CT1 Mtce Workers Request Signal Start
"CT1 Manpower Mode Requested"

"CT1 Mtce Workers Request Signal End"
IF THEN ELSE ("E(k) Assigned Mtce Workers">0,IF THEN ELSE("E(k) No. of. Mtce. Workers Requests"<="E(k) Assigned Mtce Workers","E(k) Request Dun" ,0),IF THEN ELSE("E(k) Cancelled Mtce Workers Requirements">0, "E(k) Request Dun",0))

CT1 Assigned Mtce Workers
CT1 Labour Requirement Outflow-CT1 Cancelled Maintenance Workers Requirements

CT1 Assigned Mtce Workers Inflow
IF THEN ELSE(CT1 Available Mtce Labour>0,IF THEN ELSE("AMW (CT1) In"<=CT1 Available Mtce Labour,"AMW (CT1) In",CT1 Available Mtce Labour),0)

CT1 Assigned Mtce Workers Sink
IF THEN ELSE(CT1 Assigned Mtce Workers>0,IF THEN ELSE("CT1 No. of. Mtce. Workers Request"<=CT1 Assigned Mtce Workers,CT1 Assigned Mtce Workers ,0),0)

CT1 Available Mtce Labour
CT1 Available Mtce Labour Inflow-CT1 Cancelled Maintenance Workers Requirements-CT1 Assigned Mtce Workers Inflow

CT1 Available Mtce Labour Inflow
IF THEN ELSE(CT1 Manpower Mode Requested<>0, "E(k) No. of. Mtce. Workers Requests" ,0)

CT1 Cancelled Maintenance Workers Requirements
IF THEN ELSE(CT1 Available Mtce Labour Inflow>0,IF THEN ELSE(CT1 Available Mtce Labour>0,CT1 Available Mtce Labour,0) ,0)

AMW (CT1) In
IF THEN ELSE("AMW (CT1)"<"CT1 No. of. Mtce. Workers Request", IF THEN ELSE(Mtce Recruitment In Process=0,IF THEN ELSE(Inactive Mtce Personnel>0,IF THEN ELSE(Inactive Mtce Personnel>=Total Requested Mtce Labour, If Then Else(CT1 Mtce Assignment Delay= CT1 Mtce Assignment Delay Period, "CT1 No. of. Mtce. Workers Request" ,0),0) ,0),0),0)

AMW (CT1) Out
IF THEN ELSE("AMW (CT1)">0, IF THEN ELSE(CT1 Restart Rate>0 :AND:CT1 Mtce Rate=0,"AMW (CT1)" ,IF THEN ELSE(CT1 Restart Rate=0 :AND:CT1 Mtce Rate=0,IF THEN ELSE(CT1 Available Mtce Labour Inflow>0, If Then Else(CT1 Mtce Assignment Completion Delay= CT1 Mtce Assignment Completion Delay Period, "AMW (CT1)" ,0) ,0) ,0)),0)

CT1 PM Recruitment Countdown
IF THEN ELSE(("CT1 Time to PM"-"Recruitment (Rec.) Delay Period")>=0,"CT1 Time to PM"-"Recruitment (Rec.) Delay Period" ,200000)

CT1 Mtce Personal Perceived Active and Unavailable
IF THEN ELSE((CT1 Intervention Period-CT1 Mtce Process)>"Recruitment (Rec.) Delay Period","AMW (CT1)" ,0)

System Failure
Max(VLVS Downtime,Max(PPNG Downtime,Max(OTHR Downtime,Max(MfHE Downtime,Max (MCHE Downtime,Max (GTHS Downtime,Max (GTD Downtime,Max (GST2 Downtime,Max(GST1 Downtime,Max(CT1 Downtime,CT2 Downtime))))))))))

Time to TA Mtce Start
IF THEN ELSE(System CM Intervention Time >= Time to TA Mtce :AND: System CM Intervention Time>0,Time to TA Mtce,IF THEN ELSE(POP>0 :AND:POP<=Plant Useful Life,IF THEN ELSE(CT1 Mtce Mode<>1,IF THEN ELSE(TA Mtce Done=0,TIME STEP ,0) ,0),0))

TA Mtce Start Initiation
IF THEN ELSE(TA Mtce Done=1,IF THEN ELSE(Time to TA Mtce<=0, ABs(Time to TA Mtce)+"Turnaround (TA) Mtce Interval",0),0)

Inactive Mtce Personnel
Mtce Personnel Inflow+"MW (CT1) Out"+"MW (CT2) Out"+"MW (GST1) Out"+"MW (GST2) Out"+"MW (GTD) Out"+"MW (GTHS) Out"+"MW (MCHE) Out"+"MW (MFHE) Out"+"MW (OTHR) Out"+"MW (PPNG) Out"+"MW (TRPN) Out"+"MW (VLVS) Out"-Mtce Personnel Outflow-"AMW (CT1) In"-"MW (CT2) In"-"MW (GST1) In"-"MW (GST2) In"-"MW (GTD) In"-"MW (GTHS) In"-"MW (MCHE) In"-"MW (MFHE) In"-"MW (OTHR) In"-"MW (PPNG) In"-"MW (TRPN) In"-"MW (VLVS) In"

Mtce Personnel Inflow

IF THEN ELSE(Mtce Recruitment Delay="Recruitment (Rec.) Delay Period",IF THEN ELSE(Total Mtce Personnel in Service<("Max. Mtce Workforce No. Allowable"),IF THEN ELSE((Total Mtce Personnel in Service+Workforce for Mtce Recruitment)>=("Max. Mtce Workforce No. Allowable"),("Max. Mtce Workforce No. Allowable")-Total Mtce Personnel in Service ,Workforce for Mtce Recruitment) ,0),0)

Mtce Personnel Outflow
IF THEN ELSE(POP>0,IF THEN ELSE(Mtce Budget capability>Total Mtce Personnel in Service,IF THEN ELSE(Workforce Assignment Process<=0:OR:Workforce Assignment Process End=1,IF THEN ELSE(Total Mtce Personnel in Service>"Min Mtce Workforce No. Allowable",IF THEN ELSE(Active Mtce Personnel>="Min Mtce Workforce No. Allowable"

,Inactive Mtce Personnel ,Total Mtce Personnel in Service-"Min Mtce Workforce No. Allowable") ,0),0),IF THEN ELSE(Inactive Mtce Personnel>=(Total Mtce Personnel in Service-Mtce Budget capability),(Total Mtce Personnel in Service-Mtce Budget capability),Inactive Mtce Personnel)) ,0)

Workforce for Maintenance Recruitment
Mtce Recruitment Rate-Mtce Personnel Flow In

Mtce Recruitment Rate
IF THEN ELSE(Mtce Recruitment Delay=0,IF THEN ELSE(Constrained Mtce Personnel Gap>0,IF THEN ELSE(((Constrained Mtce Personnel Gap*Mtce Resource Availability Factor)-integer(Constrained Mtce Personnel Gap*Mtce Resource Availability Factor))>=0.5,integer(Constrained Mtce Personnel Gap*Mtce Resource Availability Factor)+1 ,integer(Constrained Mtce Personnel Gap*Mtce Resource Availability Factor)) ,0) ,0)

Constrained Mtce Personnel Gap
IF THEN ELSE(Desired Mtce Personnel Gap>=0,IF THEN ELSE((Desired Mtce Personnel Gap+Total Mtce Personnel in Service)<=Mtce Fund capability,Desired Mtce Personnel Gap ,IF THEN ELSE(Total Mtce Personnel in Service>=Mtce Fund capability,0 ,Mtce Fund capability-Total Mtce Personnel in Service)), 0)

Desired Mtce Personnel Gap
"Personnel Gap (Non-Regular Mtce)"+"Personnel Gap (Regular Mtce)"

Personnel Gap (Regular Mtce)
IF THEN ELSE(Mtce Personnel Gap>0,IF THEN ELSE((Mtce Personnel Gap+Total Mtce Personnel in Service)<="Min Mtce Workforce No. Allowable",Mtce Personnel Gap ,IF THEN ELSE(Total Mtce Personnel in Service>="Min Mtce Workforce No. Allowable",0 ,"Min Mtce Workforce No. Allowable"-Total Mtce Personnel in Service)) ,0)

Personnel Gap (Non-Regular Mtce)
IF THEN ELSE("Personnel Gap (Regular Mtce)">=0,IF THEN ELSE((Mtce Personnel Gap+Total Mtce Personnel in Service)>"Min Mtce Workforce No. Allowable",IF THEN ELSE((Mtce Personnel Gap+Total Mtce Personnel in Service)<="Max. Mtce Workforce No. Allowable",Mtce Personnel Gap ,(Mtce Personnel Gap+Total Mtce Personnel in

Service)-"Max. Mtce Workforce No. Allowable") ,IF THEN ELSE(Total Mtce Personnel in Service<="Min Mtce Workforce No. Allowable","Min Mtce Workforce No. Allowable"-Total Mtce Personnel in Service,0)) ,0)

Mtce Personnel Gap
Personnel Rquired for Mtce

Personnel Rquired for Mtce
Personnel required for TA Mtce+"Personnel Required. for CM Mtce"+Personnel Required for PM

Personnel Required for CM Mtce
IF THEN ELSE("Unplanned Mtce Rec. Decision">=1,IF THEN ELSE(CM Workforce Pressure-integer(CM Workforce Pressure)>=0.5,integer(CM Workforce Pressure)+1 ,integer(CM Workforce Pressure)) ,0)

Personnel Required for PM

IF THEN ELSE("Decision for PM Rec."=1 :AND:"PM personnel Rec. Window"=1,PM Workforce Pressure ,0)

Personnel required for TA Mtce
IF THEN ELSE("Decision for TA Rec."=1,IF THEN ELSE("TA Personnel Rec. Window"=0,TA Mtce Workforce Pressure ,IF THEN ELSE("TA Personnel Rec. Window">0,IF THEN ELSE(System CM Intervention Time >= Time to TA Mtce :AND: System CM Intervention Time>0,TA Mtce Workforce Pressure ,0) ,0)) ,0)

PM Workforce Rec. Countdown
MIN(TRPN PM Recruitment Countdown,MIN(OTHR PM Recruitment Countdown,MIN(PPNG PM Recruitment Countdown,MIN(GTHS PM Recruitment Countdown,MIN(VLVS PM Recruitment Countdown,MIN(GST2 Recruitment Countdown,MIN(GST1 Recruitment Countdown,MIN(MCHE PM Recruitment Countdown,MIN(MfHE PM Recruitment Countdown,MIN(GTD PM Recruitment Countdown,MIN(CT1 PM Recruitment Countdown,CT2 PM Recruitment Countdown)))))))))))

CM Workforce Pressure
IF THEN ELSE(Perceived Personnel Available for Mtce Service>0,IF THEN ELSE((Tot CM Manpower Requests+Tot PM Manpower Requests)>Perceived Personnel Available for Mtce Service,IF THEN ELSE(((Tot CM Manpower Requests/(Tot CM Manpower Requests+Tot PM Manpower Requests))*((Tot CM Manpower Requests+Tot PM Manpower Requests)-Perceived Personnel Available for Mtce Service))-integer(((Tot CM Manpower Requests/(Tot CM Manpower Requests+Tot PM Manpower Requests))*((Tot CM Manpower Requests+Tot PM Manpower Requests)-Perceived Personnel Available for Mtce Service)))>=0.5,integer(((Tot CM Manpower Requests/(Tot CM Manpower Requests+Tot PM Manpower Requests))*((Tot CM Manpower Requests+Tot PM Manpower Requests)-Perceived Personnel Available for Mtce Service)))+1 ,integer(((Tot CM Manpower Requests/(Tot CM Manpower Requests+Tot PM Manpower

Requests))*((Tot CM Manpower Requests+Tot PM Manpower Requests)-Perceived Personnel Available for Mtce Service)))) ,0),0)

PM Workforce Pressure
IF THEN ELSE("PM Workforce Rec. Countdown">=1 :AND:PM Mtce Personnel Request=1,IF THEN ELSE((Tot CM Manpower Requests+Tot PM Manpower Requests)>Perceived Personnel Available for Mtce Service,IF THEN ELSE(((Tot PM Manpower Requests/(Tot CM Manpower Requests+Tot PM Manpower Requests))*((Tot CM Manpower Requests+Tot PM Manpower Requests)-Perceived Personnel Available for Mtce Service))-integer(((Tot PM Manpower Requests/(Tot CM Manpower Requests+Tot PM Manpower Requests))*((Tot CM Manpower Requests+Tot PM Manpower Requests)-Perceived Personnel Available for Mtce Service)))>=0.5,integer(((Tot PM Manpower Requests/(Tot CM Manpower Requests+Tot PM Manpower Requests))*((Tot CM Manpower Requests+Tot PM Manpower Requests)-Perceived Personnel Available for Mtce Service)))+1 ,integer(((Tot PM Manpower Requests/(Tot CM Manpower Requests+Tot PM Manpower Requests))*((Tot CM Manpower Requests+Tot PM Manpower Requests)-Perceived Personnel Available for Mtce Service)))),0) ,0)

TA Mtce Workforce Pressure
IF THEN ELSE("TA Workforce Rec. Countdown">=0 :AND:TA Personnel Request=1,IF THEN ELSE((Perceived Personnel Available for Mtce Service-"Tot. TA Man Power Requirement")<0,("Tot. TA Man Power Requirement"-Perceived Personnel Available for Mtce Service) ,0) ,0)

Perceived Personnel Available for Mtce Service
Total Mtce Personnel in Service-Mtce Personal Perceived Active and Unavailable

Mtce Personal Perceived Active and Unavailable
CT1 Mtce Personal Perceived Active and Unavailable+CT2 Mtce Personal Perceived Active and Unavailable+GTD Mtce Personal Perceived Active and Unavailable+MfHE Mtce Personal Perceived Active and Unavailable+MCHE Mtce Personal Perceived Active and Unavailable+GST1 Mtce Personal Perceived Active and Unavailable+GST2 Mtce Personal Perceived Active and Unavailable+VLVS Mtce Personal Perceived Active and Unavailable+GTHS Mtce Personal Perceived Active and Unavailable+PPNG Mtce Personal Perceived Active and Unavailable+OTHR Mtce Personal Perceived Active and Unavailable+TRPN Mtce Personal Perceived Active and Unavailable

Inventory on hand
Integ(Inventory Receiving Rate-Inventory Utilisation Rate)
Initial Value(CM/PM Material Order Units)

Inventory Utilisation Rate
IF THEN ELSE(Inventory on hand>0,IF THEN ELSE(Inventory on hand>=(Periodic Material Usage Rate/Inventory Usage Efficiency Factor),Periodic Material Usage Rate/Inventory Usage Efficiency Factor ,0) ,0)

Delayed Inventory
Integ(Inventory Order Rate-Inventory Arrival Rate)

Initial Value(0)

CM/PM Material Order Units
Desired PM Usage Period*PM Mtce Expense Rate

Inventory Order Rate
IF THEN ELSE(Inventory Lot Size for Order>0,IF THEN ELSE(Delayed Inventory<=0,Inventory Lot Size for Order ,IF THEN ELSE(Delayed Inventory ="CM/PM Material Order Units" :AND: Inventory Lot Size for Order=TA Mtce Material Order Units,Inventory Lot Size for Order,IF THEN ELSE(Delayed Inventory=TA Mtce Material Order Units :AND: Inventory Lot Size for Order="CM/PM Material Order Units",Inventory Lot Size for Order ,0))),0)

Inventory Arrival Rate
IF THEN ELSE(Delayed Inventory>0,IF THEN ELSE(Delayed Inventory<=0.3*"CM/PM Material Order Units",Delayed Inventory ,IF THEN ELSE("(TA/CM/PM) ID Period">0,IF THEN ELSE(Delayed Inventory>=("CM/PM Material Order Units"+TA Mtce Material Order Units),("CM/PM Material Order Units"+TA Mtce Material Order Units),Delayed Inventory),IF THEN ELSE("(CM/PM) ID Period">0 :AND:"(TA/CM/PM) ID Period"<=0,IF THEN ELSE(Delayed Inventory>="CM/PM Material Order Units","CM/PM Material Order Units",Delayed Inventory),IF THEN ELSE(TA ID Period>0 :AND:"(CM/PM) ID Period"<=0,IF THEN ELSE(Delayed Inventory>=TA Mtce Material Order Units,TA Mtce Material Order Units,Delayed Inventory),0)))),0)

CM/PM Material Order Units
Desired PM Usage Period*PM Mtce Expense Rate

TA Mtce Material Order Units
TA Mtce Expense Rate*Desired TA Mtce Usage Period

Inventory Lot Size for Order
IF THEN ELSE (Inventory on hand< Reorder Point, IF THEN ELSE((Inventory on hand-Reorder Point)< "CM/PM SPandO Costs per Intervention", IF THEN ELSE(Delayed Inventory <=0, IF THEN ELSE(System UF=1, IF THEN ELSE(System CM Intervention Time < Time to TA Mtce, IF THEN ELSE((Inventory on hand +"Used Material (TA)")< "TA SPandO Costs per Intervention", IF THEN ELSE(ABs(Time to TA Mtce)<=Average Lead Time, IF THEN ELSE("Equipment Mtce Fund (EMF)">=("CM/PM Material Order Units"+TA Mtce Material Order Units),("CM/PM Material Order Units"+TA Mtce Material Order Units) ,"Equipment Mtce Fund (EMF)") , IF THEN ELSE("Equipment Mtce Fund (EMF)">="CM/PM Material Order Units","CM/PM Material Order Units" ,"Equipment Mtce Fund (EMF)")), "CM/PM Material Order Units") ,0), IF THEN ELSE((Inventory on hand +"Used Material (TA)")< "TA SPandO Costs per Intervention", IF THEN ELSE(ABs(Time to TA Mtce)<=Average Lead Time, IF THEN ELSE("Equipment Mtce Fund (EMF)">=("CM/PM Material Order Units"+TA Mtce Material Order Units),("CM/PM Material Order Units"+TA Mtce Material Order Units) ,"Equipment Mtce Fund (EMF)") , IF THEN ELSE("Equipment Mtce Fund (EMF)">="CM/PM Material Order Units","CM/PM Material Order Units" ,"Equipment

Mtce Fund (EMF)")), "CM/PM Material Order Units")) , IF THEN ELSE(Delayed Inventory= TA Mtce Material Order Units, IF THEN ELSE(System UF=1, IF THEN ELSE(System CM Intervention Time < Time to TA Mtce, IF THEN ELSE("Equipment Mtce Fund (EMF)">="CM/PM Material Order Units","CM/PM Material Order Units" ,"Equipment Mtce Fund (EMF)") ,0) , IF THEN ELSE("Equipment Mtce Fund (EMF)">="CM/PM Material Order Units","CM/PM Material Order Units" ,"Equipment Mtce Fund (EMF)")) ,0)) ,0), IF THEN ELSE(Time to TA Mtce <=Average Lead Time, IF THEN ELSE(Delayed Inventory <=0, IF THEN ELSE((Inventory on hand +"Used Material (TA)")< "TA SPandO Costs per Intervention", IF THEN ELSE(Earliest PM Time<=Average Lead Time, IF THEN ELSE("Equipment Mtce Fund (EMF)">=("CM/PM Material Order Units"+TA Mtce Material Order Units),("CM/PM Material Order Units"+TA Mtce Material Order Units) ,"Equipment Mtce Fund (EMF)"), IF THEN ELSE("Equipment Mtce Fund (EMF)">= TA Mtce Material Order Units, TA Mtce Material Order Units ,"Equipment Mtce Fund (EMF)")),0) , IF THEN ELSE(Delayed Inventory= "CM/PM Material Order Units", IF THEN ELSE((Inventory on hand +"Used Material (TA)")< "TA SPandO Costs per Intervention", IF THEN ELSE("Equipment Mtce Fund (EMF)">= TA Mtce Material Order Units, TA Mtce Material Order Units ,"Equipment Mtce Fund (EMF)"),0) ,0)) ,0))

Total Life Cycle Cost (TLCC)
Integ(TLCC Rate)
Initial Value(0)

Feed Gas Expenses Flow
IF THEN ELSE("LNG Stock Price (Gas)">0,IF THEN ELSE(("Feed Gas Fund (FGF)"/Plant Unit Operation Window)>0,IF THEN ELSE(("Feed Gas Fund (FGF)"/Plant Unit Operation Window)>=((Periodic Feed Gas Usage Cost*(1+Feed Gas FLF))),(Periodic Feed Gas Usage Cost*(1+Feed Gas FLF)),("Feed Gas Fund (FGF)"/Plant Unit Operation Window)) ,0) ,IF THEN ELSE(("Feed Gas Fund (FGF)"/Plant Unit Operation Window)>0,IF THEN ELSE(("Feed Gas Fund (FGF)"/Plant Unit Operation Window)>=((Perodic Feed Gas Usage Cost 2*(1+Feed Gas FLF))),(Perodic Feed Gas Usage Cost 2*(1+Feed Gas FLF)),("Feed Gas Fund (FGF)"/Plant Unit Operation Window)) ,0))

LNG Stock Price (Cubic Metre gas)
IF THEN ELSE("LNG Stock Price (Gas)">0,"LNG Stock Price (Gas)"*Site Complexity Factor*Site Location Factor ,0)

Periodic Feed Gas Usage Cost
Production Start Rate*"LNG Stock Price (Cubic Metre gas)"

Fuel Gas Expenditure Flow
IF THEN ELSE("Fuel Gas Fund (FuGF)">0,IF THEN ELSE(("Fuel Gas Fund (FuGF)"/Plant Unit Operation Window)>=("Periodic Energy Cost"*(1+Fuel Gas FLF)),("Periodic Energy Cost"*(1+Fuel Gas FLF)),("Fuel Gas Fund (FuGF)"/Plant Unit Operation Window)) ,0)

Periodic Energy Cost

System Availability Status*Periodic Energy Usage*LNG Price

Periodic Energy Usage
((Gas Volume Used for Fuel/"M^3 Gas per M^3 LNG Converter"))*"mmBTU/cubic metre (LNG) converter"

Labour Expenditure Flow
IF THEN ELSE("Labour Fund (LF)">0, IF THEN ELSE("Labour Fund (LF)">=((Periodic Labour Cost*(1+"Labour Fund Leakage Factor (FLF)")))/Inflation Factor,(Periodic Labour Cost*(1+"Labour Fund Leakage Factor (FLF)"))/Inflation Factor,IF THEN ELSE("Labour Fund (LF)">=("Labour Fund (LF)"*OPEX FAF)/Inflation Factor,("Labour Fund (LF)"*OPEX FAF)/Inflation Factor ,"Labour Fund (LF)")),0)

Periodic Labour Cost
Maintenance Labour Cost+Production Labour Cost

Maintenance Labour Cost
((Inactive Mtce Personnel+Active Mtce Personnel)*Maintenance Labour Rate)/Inflation Factor

Production Labour Cost
Total Production Personnel*Operations Labour Wage Rate

Depreciation Expenses InFlow
Periodic Depreciation Expenses/Depreciation Expense Rate Factor

Maintenance Expenditure Flow
IF THEN ELSE("Equipment Mtce Fund (EMF)">0,IF THEN ELSE(("Equipment Mtce Fund (EMF)"/Plant Unit Operation Window)>=((Periodic Maintenance Cost*(1+Equipment Mtce FLF)))/Inflation Factor,(Periodic Maintenance Cost*(1+Equipment Mtce FLF))/Inflation Factor,("Equipment Mtce Fund (EMF)"/Plant Unit Operation Window)) ,0)

Periodic Depreciation Expenses
Integ(Periodic DP Expenses Rate)
Initial value(0)

Periodic Depreciation Expenses Rate
IF THEN ELSE((Plant Useful Life-POP)>=1,IF THEN ELSE(POP<=(Plant Useful Life),((ECF Outflow-Plant Salvage value)+Capital Interest Rate)/(Plant Useful Life-POP),0) ,0)

OH Expenditure Flow
IF THEN ELSE("Overhead/Other (OH) Fund">0,IF THEN ELSE(("Overhead/Other (OH) Fund"/Plant Unit Operation Window)>= (Periodic OH Cost*(1+OH FLF)),(Periodic OH Cost*(1+OH FLF)),("Overhead/Other (OH) Fund"/Plant Unit Operation Window)) ,0)

#$$$

#ECONOMIC ANALYSIS SUBSECTOR

Unit LNG Production Cost
IF THEN ELSE(Total LNG Shipped>0,("Total Life Cycle Cost (TLCC)")/(Total LNG Shipped*"mmBTU/cubic metre (LNG) converter"),0)

Total Revenue
Integ(Revenue Inflow)
Initial Value(0)

Periodic Revenue
("Shipping Rate (mmBTU)")*LNG Price

Shipping Rate (mmBTU)
(Shipping Rate*"mmBTU/cubic metre (LNG) converter")

Discounted Total Profit
Discounted Total Profit Flow In
Initial Value(0)

Discounted Total Profit Flow In
Discounted Periodic Profit

Discounted Periodic Profit
IF THEN ELSE(Discount Factor>0,Periodic LNG Profit/Discount Factor ,0)

Discount Factor
IF THEN ELSE(POP>0,(1+Periodic Discount Rate)^POP ,0)

Periodic LNG Profit
("Shipping Rate (mmBTU)"*LNG Price)-TLCC Rate

Periodic Discount Rate
(Discount Rate/(12*"Mnth-Desired Time Window Converter"))

Pay Back Period (PBP)
IF THEN ELSE(Cash Flow>0,IF THEN ELSE(POP>0,IF THEN ELSE(MODULO(POP,(12*"Mnth-Desired Time Window Converter"))=0,(Total CAPEX/(Cash Flow/(POP/(12*"Mnth-Desired Time Window Converter")))) ,0) ,0) ,0)

Cash Flow (NPV)
Integ(Cash Flow (NPV) Rate)
Initial Value(0)

Cash Flow Rate (NPV)
(Periodic LNG Profit+Depreciation Expenses InFlow)/discount Factor

ROI (NPV)
IF THEN ELSE(POP>0,IF THEN ELSE(MODULO(POP,(12*"Mnth-Desired Time Window Converter"))=0,100*(Discounted Total Profit/(POP/(12*"Mnth-Desired Time Window Converter")))/"Capital Investment (NPV)",0) ,0)

Capital Investment (NPV)
"Capital Investment (NPV) Rate"

Capital Investment (NPV) Rate
IF THEN ELSE(Discount Factor>0,(CAPEX Fund Inflow+"OPEX (Less DP Cost) Rate"+Total Interest On Capital Rate)/Discount Factor ,0)

APPENDIX B

QUANTITY SPECIFICATIONS FOR LIQUEFIED NATURAL GAS SUB SECTORS

Table B1: Specification of quantities for the budgeting and funding sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
1	Annual Equipment Maintenance Expenses	C_{XMtce}^{Annual}	$/Year	Output	Output
2	Annual OPEX (Less FG and DP Costs)	C_{XLFD}^{Annual}	$/Year	Auxiliary	Auxiliary
3	Annual OPEX (Less FG and DP Costs)/CAPEX Ratio	P_{CF}^{xLFD}	%/Year	Output	Output
4	Annual OPEX (Less FuG, FG and DP Costs)	C_{XLFuFD}^{Annual}	$/Year	Auxiliary	Auxiliary
5	Annual OPEX (Less FuG, FG and DP Costs)/CAPEX Ratio	P_{CF}^{xLFuFD}	%/Year	Output	Output
6	Average Annual Production Cost	$\bar{C}_{Prod}^{Annual}$	$/Year	Output	Output
7	Breakeven Quantity	V_{Even}^{Break}	$cm^3 LNG$	Output	Output
8	Breakeven Period	t_{Even}^{Break}	Time	Output	Output
9	Brownfield Plant Design Capacity (BPDC)	B_{Dsgn}^{Cap}	MTPA	Input	Input
10	Bulk Material Cost Per Unit BPDC	C_{BM}^{UCap}	$/MTPA	Input	Input
11	Bulk Material Cost Per Unit GPDC	C_{GM}^{UCap}	$/MTPA	Input	Input
12	CAPEX Budget	$\hat{B}_{EX}^{C}$	$	Auxiliary	Auxiliary
13	CAPEX Fund (CF)	$\hat{F}_{EX}^{C}$	$	Auxiliary	Auxiliary
14	CAPEX Funding Factor	Ψ_{EX}^{C}	Dmnl	Input	Input
15	CAPEX Fund Inflow	$\dot{F}_{EX}^{C}$	$/Time	Rate	Rate
16	Cash Flow (NPV)	G_{Cash}^{NPV}	$	State	State
17	Cash Flow Rate (NPV)	$\dot{G}_{Cash}^{NPV}$	$/Time	Rate	Rate
18	Construction Cost Per Unit BPDC	C_{BC}^{UCap}	$/MTPA	Input	Input
19	Construction Cost Per Unit GPDC	C_{GC}^{UCap}	$/MTPA	Input	Input
20	Depreciation Consideration factor	K_D	Dmnl	Input	Input

Table B1 (continued): Specification of quantities for the budgeting and funding sector

	Quantity				
SN	Description	Symbol	Dimension	Sector Type	System Type
21	Depreciation Expenses Inflow	$\dot{E}_{xDP}$	$/Time	Rate	Rate
22	Depreciation Expense Rate Factor	f_{DP}^{Exp}	1/Time	Input	Input
23	Discount Factor	f^{Disc}	Dmnl	Auxiliary	Auxiliary
24	Discount Rate	r^{Disc}	%/Year	Input	Input
25	Discounted Pay Back Period (PBP)	t_{Back}^{Pay}	Year	Output	Output
26	Discounted Periodic Profit	$\ddot{G}_{LNG}^{Disc}$	$/Time	Auxiliary	Auxiliary
27	Engineering and Project Management Cost per Unit BPDC	C_{BEpm}^{UCap}	$/MTPA	Input	Input
28	Engineering and Project Management Cost per Unit GPDC	C_{GEpm}^{UCap}	$/MTPA	Input	Input
29	Equipment Cost Per Unit BPDC	C_{BE}^{UCap}	$/MTPA	Input	Input
30	Equipment Cost Per Unit GPDC	C_{GE}^{UCap}	$/MTPA	Input	Input
31	Equipment Maintenance Expenditure Flow	$\dot{E}_{xMtce}$	$/Time	Rate	Rate
32	Equipment Maintenance Fund (EMF)	F_{Mtce}	$	State	State
33	Equipment Maintenance Funding Factor (FF)	K_{Mtce}^{FF}	Dmnl	Input	Input
34	Equipment Maintenance Fund Inflow	$\dot{F}_{Mtce}$	$/Time	Rate	Rate
35	Equipment Maintenance Fund Implementation Level (FIL)	K_{Mtce}^{IL}	Dmnl	Input	Input
36	Equipment Maintenance Fund Leakage Factor (FLF)	K_{Mtce}^{FLF}	Dmnl	Input	Input
37	LNG Cost Per Shipping Trip	$C_{Trpn}^{ShipLNG}$	$/Trip	Input	Input
38	Feed Gas Expenses Flow	$\dot{E}_{xFG}$	$/Time	Rate	Rate
39	Feed Gas Fund	F_{FG}	$	State	State
40	Feed Gas Funding Factor	K_{FG}^{FF}	Dmnl	Input	Input
41	Feed Gas Fund Inflow	$\dot{F}_{FG}$	$/Time	Rate	Rate
42	Feed Gas Fund Leakage Factor	K_{FG}^{FLF}	Dmnl	Input	Input
43	Fuel Gas Expenditure Flow	$\dot{E}_{xFuG}$	$/Time	Rate	Rate

Table B1 (continued): Specification of quantities for the budgeting and funding sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
44	Fuel Gas Fund	F_{FuG}	$	State	State
45	Feed Gas Fund Implementation Level	K_{FG}^{IL}	Dmnl	Input	Input
46	Fuel Gas Funding Factor	K_{FuG}^{FF}	Dmnl	Input	Input
47	Fuel Gas Fund Inflow	$\dot{F}_{FuG}$	$/Time	Rate	Rate
48	Fuel Gas Fund Implementation Level	K_{FuG}^{IL}	Dmnl	Input	Input
49	Fuel Gas Fund Leakage Factor	K_{FuG}^{FLF}	Dmnl	Input	Input
50	Fund Access Factor	f_{Fund}^{Access}	Dmnl	Input	Input
51	Funded Budget	B^{T}	$	State	State
52	Funded Budget Inflow	$\dot{B}^{T}$	$/Time	Rate	Rate
53	Gas Volume Used as Fuel	$\dot{V}_{FuG}$	$cm^3 gas$	Input	Auxiliary
54	Greenfield Plant Design Capacity (GPDC)	G_{Dsgn}^{Cap}	MTPA	Input	Input
55	Inflation Factor	f^{Infl}	Dmnl	Input	Input
56	Interest on Capital Policy	K_{CF}^{Intrst}	Dmnl	Input	Input
57	Inventory Ordering Costs (IOC)	$\ddot{C}_{Ord}^{Inv}$	$/hour	Auxiliary	Auxiliary
58	IOC Fraction	f_{Ord}^{I}	Dmnl	Input	Input
59	Inventory Holding Costs (IHC)	$\ddot{C}_{Hold}^{Inv}$	$/Time	Auxiliary	Auxiliary
60	IHC Fraction	f_{Hold}^{I}	Dmnl	Input	Input
61	Labour Expenditure Flow	$\dot{E}_{xLab}$	$/Time	Rate	Rate
62	Labour Fund	F_{Lab}	$	State	State
63	Labour Funding Factor	K_{Lab}^{FF}	Dmnl	Input	Input
64	Labour Fund Inflow	$\dot{F}_{Lab}$	$/Time	Rate	Rate
65	Labour Fund Implementation Level	K_{Lab}^{IL}	Dmnl	Input	Input
66	Labour Fund Leakage Factor	K_{Lab}^{FLF}	Dmnl	Input	Input
67	LNG Price	C^{LNG}	$\$/mmBTU$	Input	Input
68	LNG Stock Price (Gas)	C_{LNG}^{Gas}	$\$/cm^3 Gas$	Input	Input
69	Maintenance Labour Cost	$\ddot{C}_{Mtce}^{Lab}$	$/Time	Input	Auxiliary
70	Maintenance Labour Wage Rate	C_{mtce}^{Wage}	$/ManTime	Input	Input

Table B1 (continued): Specification of quantities for the budgeting and funding sector

SN	Quantity Description	Symbol	Dimension	Sector Type	System Type
71	Maintenance Operators Budget Factor	K_{BF}^{MP}	Dmnl	Input	Input
72	Maintenance Operators Fund	B_{MP}	$	Output	Auxiliary
73	Miscellaneous Maintenance Costs	C_{Mtce}^{MMC}	$/Time	Auxiliary	Auxiliary
74	MMC Factor	f_{Mtce}^{MMC}	%	Input	Input
75	MMBTU-LNG Converter	f_{LNG}^{mmBTU}	$\frac{mmBTU}{m_{LNG}^{3}}$	Input	Input
76	OPEX Fund Availability Factor (FAF)	Ω_{EX}^{O}	1/Time	Input	Input
77	OPEX Fund Inflow	$\dot{F}_{EX}^{O}$	$/Time	Rate	Rate
78	OPEX Fund Implementation Level (FIL)	F_{IL}^{O}	Dmnl	Input	Input
79	OPEX (Less DP Cost) Rate	$\dot{E}_{xD}^{Less}$	$/Time	Rate	Rate
80	OPEX (Less DP Cost)	E_{xD}^{Less}	$	State	State
81	OPEX (Less FG and DP Costs)	E_{xFD}^{Less}	$	State	State
82	OPEX (Less FG and DP Costs) Rate	$\dot{E}_{xFD}^{Less}$	$	Rate	Rate
83	OPEX (Less FuG, FG and DP Costs)	E_{xFuFD}^{Less}	$	State	State
84	OPEX (Less FuG, FG and DP Costs)	$\dot{E}_{xFuFD}^{Less}$	$	Rate	Rate
85	OPEX [Less overhead (OH), Feed gas	$\dot{E}_{OF}^{Less}$	$/Time	Auxiliary	Auxiliary
86	OH Expenditure Flow	$\dot{E}_{xOH}$	$/Time	Rate	Rate
87	OH Fund	F_{OH}	$	State	State
88	OH Funding Factor	K_{OH}^{FF}	Dmnl	Input	Input
89	OH Fund Inflow	$\dot{F}_{OH}$	$/Time	Rate	Rate
90	OH Fund Implementation Level	K_{OH}^{IL}	Dmnl	Input	Input
91	OH Fund Leakage Factor	K_{OH}^{FLF}	Dmnl	Input	Input
92	Owners Cost Per Unit BPDC	C_{BOwn}^{UCap}	$/MTPA	Input	Input
93	Owners Cost Per Unit GPDC	C_{GOwn}^{UCap}	$/MTPA	Input	Input
94	Owners Total Cost	C_{Own}^{Tot}	$	Auxiliary	Auxiliary
95	Periodic Depreciation Expenses	$\ddot{E}_{xDP}$	$	State	Output
96	Periodic Depreciation Expenses Rate	$\dddot{E}_{xDP}$	$/Time	Output	Auxiliary
97	Periodic Energy Cost	$\ddot{C}_{Energy}^{Usage}$	$/Time	Auxiliary	Auxiliary

Table B1 (continued): Specification of quantities for the budgeting and funding sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
98	Periodic Energy usage	$\ddot{E}_{Energy}^{Usage}$	$/Time	Auxiliary	Auxiliary
99	Periodic Feed Gas Usage Cost	$\ddot{C}_{FG}^{Usage}$	$/Time	Auxiliary	Auxiliary
100	Periodic Discount Rate	$\ddot{R}^{Disc}$	%/Time	Auxiliary	Auxiliary
101	Periodic Interest On Capital Rate	$\dot{C}_{CF}^{Intrst}$	$/Time	Rate	Rate
102	Periodic LNG Profit	$\ddot{G}_{LNG}$	$/Time	Auxiliary	Auxiliary
103	Periodic LNG Shipping Cost	$\ddot{C}_{Trpn}^{LNG}$	$/Time	Auxiliary	Auxiliary
104	Periodic Maintenance Cost	$\ddot{C}_{Mtce}$	$/Time	Auxiliary	Auxiliary
105	Periodic OPEX Budget	$\hat{B}_{EX}^{O}$	$	Input	Input
106	Periodic OPEX Budgeting Factor	Ψ_{EX}^{O}	Dmnl	Input	Input
107	Periodic OPEX Fund	$\hat{F}_{EX}^{O}$	$	Auxiliary	Auxiliary
108	Periodic OPEX (Less [FG] and DP Cost)	$\ddot{E}_{xFGDP}^{Less}$	$/Time	Auxiliary	Auxiliary
109	Periodic OH Cost	C_{OH}^{O}	$/Time	Input	Input
110	Periodic Revenue	$\ddot{G}_{Rev}$	$/Time	Auxiliary	Auxiliary
111	Periodic Shipment Delivered	$\ddot{V}_{delvd}^{Ship}$	m_{LNG}^{3}	Input	Input
112	Plant Operating Period (POP)	t^{*}	Time	Input	Auxiliary
113	Plant Salvage value	C_{slvg}	$	Auxiliary	Auxiliary
114	Plant Useful Life	P_{L}	Time	Input	Input
115	Previous activity-based OPEX Rate	$C_{PrevAct}^{OPEX}$	$/Time	Input	Input
116	Production Labour Cost	$\ddot{C}_{Prod}^{Lab}$	$/Time	Auxiliary	Auxiliary
117	Production Labour Wage Rate	W_{Prod}^{Wage}	$/ManTime	Input	Auxiliary
118	Production Operators Fund	B_{PP}	$	Output	Output
119	Production Start Rate	$\dot{V}_{start}^{LNG}$	$m_{gas}^{3}/Time$	Input	Rate
120	Profit per Unit LNG	G_{LNG}^{Unit}	$	Output	Output
121	Return On Investment [ROI]	P_{ROI}	%	Output	Output
122	Revenue Inflow	$\dot{G}_{Rev}$	$/Time	Auxiliary	Auxiliary
123	Site Complexity Factor	f_{Site}^{Cmplx}	Dmnl	Input	Input
124	Site Location Factor	f_{Site}^{Loc}	Dmnl	Input	Input

Table B1 (continued): Specification of quantities for the budgeting and funding sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
125	Shipping Expenditure Flow	$\dot{E}_{xTrpn}$	\$/Time	Rate	Rate
126	Shipping Funding Factor	K_{Trpn}^{FF}	Dmnl	Input	Input
127	Shipping Fund	F_{Trpn}	\$	State	State
128	Shipping Fund Inflow	$\dot{F}_{Trpn}$	\$/Time	Rate	Rate
129	Shipping Fund Implementation Level (FIL)	K_{Trpn}^{IL}	Dmnl	Input	Input
130	Shipping Fund Leakage Factor (FLF)	K_{Trpn}^{FLF}	Dmnl	Input	Input
131	Shipping Rate	$\dot{V}_{LNG}^{shipped}$	$m^3/Time$	Input	Rate
132	Shipping Rate (mmBTU)	$\dot{V}_{LNGBTU}^{shipped}$	mmBTU/Time	Auxiliary	Auxiliary
133	System Availability Status	A_S^S	Dmnl	Input	Auxiliary
134	Total Bulk Materials Cost	C_M^T	\$	Auxiliary	Auxiliary
135	Total CAPEX Fund (CF)	$\hat{F}_{EX}^{TC}$	\$	State	State
136	Total Construction Cost	C_c^T	\$	Auxiliary	Auxiliary
137	Total Depreciation Expenses	D^T	\$	State	State
138	Total Discounted Profit Flow In	$\dot{G}_{LNG}^{Disc}$	\$/Time	Auxiliary	Auxiliary
139	Total Discounted Profit	G_{LNG}^{Disc}	\$	State	State
140	Total Discounted Profit	G_{LNG}^{NDisc}	\$	State	State
141	Total Engineering and Project Management Cost	C_{Epm}^T	\$	Auxiliary	Auxiliary
142	Total Equipment Cost	C_E^T	\$	Auxiliary	Auxiliary
143	Total Equipment Maintenance Expenses	E_{xMtce}	\$	State	State
144	Total Feed Gas Expenses	E_{xFG}	\$	State	State
145	Total Fuel Gas Expenses	E_{xFuG}	\$	State	State
146	Total Investment	C_{Inv}^{Tot}	\$	Auxiliary	Auxiliary
147	Total Labour Expenses	E_{xLab}	\$	State	State
148	Total Life Cycle Cost (TLCC)	C_{LCC}^{Tot}	\$	State	State
149	TLCC Rate	$\dot{C}_{LCC}^{Tot}$	\$/Time	Rate	Rate

Table B1 (continued): Specification of quantities for the budgeting and funding sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
150	Total LNG Shipped	$V_{LNG}^{shipped}$	m^3	State	State
151	Total Non-Discounted Profit Flow In	$\dot{G}_{LNG}^{NDisc}$	$/Time	Auxiliary	Auxiliary
152	Total OH Expenses	E_{xOH}	$	State	State
153	Total OPEX Fund	$\hat{F}_{EX}^{TO}$	$	State	State
154	Total Periodic Interest on Capital	$\dot{E}_{CF}^{Intrst}$	$	Rate	Rate
155	Total Periodic Maintenance Cost	$\ddot{C}_{Mtce}^{Tot}$	$/Time	Auxiliary	Auxiliary
156	Total Production Personnel	W_{Prod}^{Tot}	Man	Input	Auxiliary
157	Total Revenue	G_{Rev}^{Tot}	$	State	State
158	Total Shipping Expenses	E_{xTrpn}	$	State	State
159	Unit LNG Production Cost	$C_{Prod}^{UnitLNG}$	$/MMBTU	Output	Output
160	Operating Time -Year Conversion Factor	f_{Yr}^{POP}	$Time/Year$	Input	Input

Table B2: Quantity specification for the production operation sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
1	Active Production Personnel (PP)	f_{PAsign}^{WAct}	$1/Time$	Input	Auxiliary
2	Active PP Assignment Termination	f_{PTerm}^{WAct}	$1/Time$	Input	Input
3	Active PP	W_{Prod}^{Act}	Man	State	State
4	Active PP Firing Frequency	f_{PFire}^{WAct}	$1/Time$	Input	Input
5	Active PP Firing Rate	$\dot{W}_{PFire}^{Act}$	Man/Time	Rate	Rate
6	Active Production Personnel In Flow	$\dot{W}_{prod}^{ActIn}$	Man/Time	Rate	Rate
7	Active Production Personnel Outflow	$\dot{W}_{prod}^{ActOut}$	Man/Time	Rate	Rate
8	Available LNG Storage Limit	V_{SLim}^{LNG}	m^3	Auxiliary	Auxiliary
9	Available LNG Storage Limit (Gas Equivalent)	V_{SLim}^{LNGge}	m_{gas}^3	Auxiliary	Auxiliary
10	Brownfield Plant Design Capacity	B_{Dsgn}^{Cap}	MTPA	Auxiliary	Auxiliary
11	Brownfield Unit Train Capacity	V_{Tr}^{B}	MTPA/Train	Input	Input
12	Charter Travel Time	t_{Trvl}^{Ship}	$Time$	Input	Input
13	Constrained Workforce for Production	W_{Prod}^{Con}	Man/Time	Auxiliary	Auxiliary
14	Current Plant Capacity (CPP)	P_{CC}	MTPA	Auxiliary	Auxiliary
15	Customer Order (CO)	V^{co}	m^3	Input	Input
16	Accumulated Cos	V_{order}^{cust}	m^3	State	State
17	CO Rate	$\dot{V}_{order}^{cust}$	$m^3/Time$	Rate	Rate
18	Gas-LNG Converter	f_{LNG}^{Gas}	m_{gas}^3/m_{LNG}^3	Input	Input
19	Desired Gas Usage Volume	V_{Du}^{LNGge}	m_{gas}^3	Auxiliary	Auxiliary
20	Desired LNG Stock (MT)	V_{D}^{LNGMT}	MT	Auxiliary	Auxiliary
21	Desired LNG Stock	V_{D}^{LNG}	m^3	Auxiliary	Auxiliary
22	Desired LNG stock (Energy Equivalence)	V_{D}^{LNGge}	$mmBTU$	Auxiliary	Auxiliary
23	Desired Production Start Volume	V_{Ds}^{LNGge}	m_{gas}^3	Auxiliary	Auxiliary
24	Discrepancy In LNG Inventory	δ^{LNG}	m^3	Auxiliary	Auxiliary
25	Desired Maintenance Workforce	W_{Mtce}^{Des}	Man	Output	Auxiliary

Table B2 (Continued): Quantity specification for the production operation sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
26	Desired Workforce Upper Tolerance	f_{UProd}^{Trnce}	%	Input	Input
27	Desired Workforce Lower Tolerance	f_{LProd}^{Trnce}	%	Input	Input
28	Equipment Maintenance Fund	F_{Mtce}	$	Input	State
29	Expected Fuel Cost	C^{Fu}	$	Output	Output
30	Expected Production Workforce Capability	K_{Exptd}^{ProdWC}	$\frac{m_{gas}^3}{PersonTime}$	Auxiliary	Auxiliary
31	Expected Production Workforce Number	W_{Exptd}^{PExe}	Man	Auxiliary	Auxiliary
32	Expected Workload Execution Time	t_{Exptd}^{WLExe}	Time	Input	Input
33	Expected Production Workload	W_{PExptd}^{Load}	ManTime	Auxiliary	Auxiliary
34	Expected Production Workforce Requirement per Workload	W_{prod}^{UReqd}	$\frac{PersonTime}{m_{gas}^3}$	Input	Input
35	Facility Location Factor	f^{Loc}	Dmnl	Input	Input
36	Feed Gas Accessibility Delay Signal	D_{Feed}^{NG}	Dmnl	Auxiliary	Auxiliary
37	Feed Gas Fund	F_2	$	Input	State
38	Feed Gas Supply Frequency	f_{Feed}^{NG}	$1/Time$	Auxiliary	Auxiliary
39	Feed Gas Supply Interval	t_{Feed}^{NG}	$Time$	Input	Input
40	Feed Gas Rate	$\dot{V}_{Feed}^{NG}$	$m_{gas}^3/Time$	Rate	Rate
41	Fuel Gas Fund	F_3	$	Input	State
42	Fuel Usage Factor	f_{Fu}^{Usage}	%	Input	Input
43	Gas Delivery Capability Factor	K^{GD}	$Dmnl$	Input	Input
44	Gas Delivery Volume	V_{Dd}^{LNGge}	m_{gas}^3	Auxiliary	Auxiliary
45	Gas In Process Discrepancy	δ^{NG}	m_{gas}^3	Auxiliary	Auxiliary
46	Greenfield Plant Design Capacity	G_{Dsan}^{Cap}	MTPA	Auxiliary	Auxiliary
47	Greenfield Unit Train Capacity	V_{Tr}^{G}	MTPA/Train	Input	Input
48	Heel allocation	$\dot{V}_{Loss}^{Heel}$	%	Input	Input
49	Inactive Production Personnel	W_{prod}^{Inact}	$People$	State	State

Table B2 (Continued): Quantity specification for the production operation sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
50	Inactive Production Personnel Firing Frequency	f_{prod}^{WFire}	$1/Time$	Input	Input
51	Jetty BOG Factor	f_{BOG}^{Jetty}	$Dmnl$	Rate	Rate
52	Jetty BOG Rate	$\dot{V}_{BOG}^{Jetty}$	$m^3/Time$	Rate	Rate
53	Labour From Budget Capability	W_{Prod}^{BugCap}	Man/Time	Auxiliary	Auxiliary
54	Labour Fund	F_4	$	Input	State
55	LNG Inflow for Shipping	$\dot{V}_{Prep}^{ship}$	$m^3/Time$	Rate	Rate
56	LNG Price	C^{LNG}	$\$/MMBtu$	Input	Input
57	LNG Shipment	V_{LNG}^{ship}	m_{LNG}^3	State	State
58	LNG Production Rate	$\dot{V}_{prod}^{LNG}$	$m^3/Time$	Rate	Rate
59	LNG Shipped	V_{Order}^{ship}	m^3	State	State
60	LNG Ship Loading Interval	t_{Load}^{ship}	$Time$	Input	Input
61	LNG Ship Loading Rate	$\dot{V}_{Load}^{ship}$	$m^3/Time$	Rate	Rate
62	LNG Storage Capacity	V_{SCap}^{LNG}	m^3	Input	Input
63	Shipment Preparation Delay	D_{Prep}^{ship}	$Time$	Input	Input
64	Maximum (Max.) Shipload Capacity	V_{Max}^{ship}	m^3	Input	Input
65	Maximum Production Workforce No. Allowable	W_{Prod}^{Max}	Man	Auxiliary	Auxiliary
66	Minimum Production Workforce No. Allowable	W_{Prod}^{Min}	Man	Auxiliary	Auxiliary
67	Maximum Loading Fraction	$f_{Ship}^{MaxLoad}$	$Dmnl$	Input	Input
68	MMBTU-LNG Converter	f_{LNG}^{mmBTU}	$\frac{mmBTU}{m_{LNG}^3}$	Input	Input
69	Natural Gas (NG) Conversion Factor	K^{NGC}	$Dmnl$	Input	Input
70	NG Available For Production	V_{Aprod}^{NG}	m_{gas}^3	State	State
71	NG in Process	V_{inproc}^{NG}	m_{gas}^3	State	State
72	NG In Process Conversion Rate	$\dot{V}_{inproc}^{NGc}$	$m_{gas}^3/Time$	Rate	Rate
73	NG In Process Waste Rate	$\dot{V}_{inproc}^{NGw}$	$m_{gas}^3/Time$	Rate	Rate

Table B2 (Continued): Quantity specification for the production operation sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
74	NG Plant Capacity	$V_{pl\_max}^{NG}$	m_{gas}^{3}	Auxiliary	Auxiliary
75	NG Plant Capacity Factor	K^{PlC}	$Dmnl$	Input	Input
76	NG Stock Depletion Rate	$\dot{V}_{stock}^{NG}$	$m_{gas}^{3}/Time$	Rate	Rate
77	NG Stock Joint Use Factor	K_{stock}^{NG}	Dmnl	Input	Input
78	NG Utilisation Rate	$\dot{V}_{used}^{NG}$	$m_{gas}^{3}/Time$	Rate	Rate
79	NG Volume Required for Production	V_{Rprod}^{NG}	m_{gas}^{3}	Auxiliary	Auxiliary
80	Fired Active Prod Operators	W_{PFire}^{Act}	$Man/Time$	Rate	Rate
81	Non-Mtce. Related Feed Gas Delays	D_{Feed}^{NG*}	Dmnl	Input	Input
82	No Production Workforce Recruitment In Progress	f_{PProg}^{NRcrit}	Dmnl	Auxiliary	Auxiliary
83	Number of Brownfield Trains	N_{Tr}^{B}	Dmnl	Input	Input
84	Number of Greenfield Trains	N_{Tr}^{G}	Dmnl	Input	Input
85	OPEX Fund Implementation Level (OFIL)	F_{IL}^{O}	Dmnl	Input	Input
86	Order Receipt Policy on TA Mtce.	f_{Policy}^{OrdRct}	Dmnl	Input	Input
87	Orders for Shipping	V_{PO}^{ship}	m^3	State	State
88	Order Release (OR) Rate	$\dot{V}_{OR}^{PO}$	$m^3/Time$	Rate	Rate
89	Orders Approved for Shipping	$\dot{V}_{App}^{Ship}$	$m^3/Time$	Rate	Rate
90	Periodic OR Fraction	K_{OR}^{delay}	$1/Time$	Input	Input
91	Overhead/Other (OH) Fund	F_{OH}	$	Input	Auxiliary
92	Perceived Plant LNG Requirement (PPLR)	V^{PPLR}	m^3	Auxiliary	Auxiliary
93	PPLR (Gas Equivalent)	V^{PPLRge}	m_{gas}^{3}	Auxiliary	Auxiliary
94	Periodic Plant Capacity (LNG)	P_{PC}	$m^3/Time$	Auxiliary	Auxiliary
95	Periodic Plant Capacity (Gas Equivalent)	P_{PC}^{ge}	$m_{gas}^{3}/Time$	Output	Output
96	Perceived Production Workforce Capability	K^{WC}	$m_{gas}^{3}/People$	Auxiliary	Auxiliary

Table B2 (Continued): Quantity specification for the production operation sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
97	Periodic workforce wages	$\dot{W}_{Prod}^{Wage}$	$\$/Time$	Auxiliary	Auxiliary
98	Plant Design Capacity (PDC)	P_{DC}	MTPA	Auxiliary	Auxiliary
99	PDC (Gas Equivalent [GE])	P_{DC}^{ge}	m_{gas}^3	Auxiliary	Auxiliary
100	Plant Operation Bottleneck Factor	K_{OBN}^P	Dmnl	Input	Input
101	Plant Operating Period (POP)	t^*	Time	Auxiliary	Auxiliary
102	Plant Operation Window (POW)	t_{pw}	Time	State	State
103	POW Wind-Up Rate	$\dot{t}_{pw}$	OpsTime/Time	Rate	Rate
104	Plant Unit Operation Window	t_{pw}^*	Time	Input	Input
105	Plant Useful Life	P_L	Time	Input	Input
106	PPNG Mtce. Action	D_{Feed}^{NG**}	Dmnl	Input	Auxiliary
107	Plant Productivity	K^{PrC}	Dmnl	Input	Input
108	Produced LNG In Storage	V_{prod}^{LNG}	m^3	State	State
109	Production Labour Wage Rate	W_{Prod}^{Wage}	$/ManTime	Input	Input
110	Production Order (PO) Frequency	K_F^{po}	$1/Time$	Auxiliary	Auxiliary
111	Accumulated POs	V_{Acc}^{PO}	m^3	State	State
112	PO Accumulation Rate	$\dot{V}_{order}^{prod}$	$m^3/Time$	Rate	Rate
113	PO Interval	t^{po}	$Time$	Input	Input
114	PO Rate	$\dot{V}_{order}^{prod}$	$m^3/Time$	Rate	Rate
115	Production Operation Fund	B_{PP}	$	Input	Output
116	Production Operator Productivity	θ_{Prod}	Dmnl	Input	Input
117	Production Recruitment Delay	t_{Prod}^{DRcrit}	Time	Input	State
118	Production Recruitment Delay Period	$t_{Prod}^{DRcrit*}$	Time	Input	Input
119	Production Resource Availability Factor	f_{Prod}^{ResAv}	Dmnl	Input	Input
120	Production Start Rate	$\dot{V}_{start}^{LNG}$	$m_{gas}^3/Time$	Rate	Rate
121	Production Personnel Firing Rate	$\dot{W}_{prod}^{Fire}$	$Man/Time$	Rate	Rate
122	Production Workforce for Recruitment	W_{prod}^{Rcrit}	Man	State	State

Table B2 (Continued): Quantity specification for the production operation sector

SN	Description	Quantity Symbol	Dimension	Sector Type	System Type
123	Production Workforce Recruitment Rate	$\dot{W}_{prod}^{Rcrit}$	Man/Time	Rate	Rate
124	Production Workforce Recruitment Request	W_{PRqst}^{Rcrit}	$Man/Time$	Auxiliary	Auxiliary
125	Production Workforce Recruitment In Progress	f_{PProg}^{Rcrit}	Dmnl	Auxiliary	Auxiliary
126	Recruited Production Personnel Release Frequency	f_{Prod}^{RcrRel}	$1/Month$	Input	Input
127	Recruited Production Personnel Release Rate	$\dot{W}_{prod}^{RcrRel}$	Man/Time	Rate	Rate
128	Required Production Workforce Backlog	W_{Prod}^{BLog}	Man/Time	Auxiliary	Auxiliary
129	Residual LNG Desired from Production	V_{Res}^{prod}	m^3	Auxiliary	Auxiliary
130	Residual LNG Desired from Production (GE)	V_{Res}^{prodGe}	m^3gas	Auxiliary	Auxiliary
131	Ship maximum LNG varying capacity	$\mathrm{V}_{Load}^{MaxShip}$	m^3	Input	Input
132	shipment delivery rate	$\dot{V}_{delvd}^{Ship}$	$m^3/Time$	Rate	Rate
133	Shipping Rate	$\dot{V}_{LNG}^{shipped}$	$m^3/Time$	Rate	Rate
134	System Availability Status	A_S^S	Dmnl	Input	Auxiliary
135	Total CF Fund	$\hat{F}_{EX}^{TC}$	$	Input	State
136	Total LNG produced	V_{prod}^{TotLNG}	m^3	State	State
137	Total LNG shipment delivered	V_{delvrd}^{Ship}	m^3	State	State
138	total LNG shipment in transit	V_{Trnst}^{Ship}	m^3	State	State
139	Total Production Personnel	W_{prod}^{Tot}	Man	Auxiliary	Auxiliary
140	Total Waste (LNG Equivalent)	V_{inproc}^{w}	m^3	Auxiliary	Auxiliary
141	Total Waste NG from Process	V_{inproc}^{wge}	m_{gas}^3	State	State
142	Transit BOG Fraction	f_{BOG}^{Trnst}	$\%/Time$	Rate	Rate
143	Transit BOG Rate	$\dot{V}_{BOG}^{Trnst}$	$m^3/Time$	Rate	Rate

Table B2 (Continued): Quantity specification for the production operation sector

	Quantity				
SN	**Description**	**Symbol**	**Dimension**	**Sector Type**	**System Type**
144	Transportation Equipment (TRPN) Uptime	E_{A}^{TRPN}	$Time$	Input	Rate
145	Turnaround (TA) Maintenance Action	E_{Mtce}^{TaAct}	$Time$	Input	Auxiliary
146	Workforce Estimated for Production	W_{Prod}^{Est}	Man	Auxiliary	Auxiliary
147	Workforce Perceived for Production	W_{Prod}^{Perc}	Man	Auxiliary	Auxiliary

Table B3: Quantity specification for the Maintenance sector

Quantity					
SN	**Description**	**Symbol**	**Dimension**	**Sector Type**	**System Type**
1	Active Maintenance Workers	W_{MtceS}^{Act}	Man	Auxiliary	Auxiliary
2	Active Maintenance Workers (AMW) for E_k [E_k]	W_{Mtcek}^{Act}	Man	State	State
3	AMW In for E_k	$\dot{W}_{Mtcek}^{ActIn}$	Man/Time	Rate	Rate
4	AMW Out for E_k	$\dot{W}_{Mtcek}^{ActOut}$	Man/Time	Rate	Rate
5	Assigned Maintenance Workers for E_k	W_{Mtcek}^{Ass}	Man	State	State
6	Assigned Maintenance Workers Inflow for E_k	$\dot{W}_{Mtcek}^{AssIn}$	Man/Time	Rate	Rate
7	Assigned Maintenance Workers Sink for E_k	$\dot{W}_{Mtcek}^{AssSink}$	Man/Time	Rate	Rate
8	Available Maintenance Labour Inflow for E_k	$\dot{W}_{Mtcek}^{AvIn}$	Man/Time	Rate	Rate
9	Available Maintenance Labour for E_k	W_{Mtcek}^{Av}	Man	State	State
10	Available Labour Requests	W_{S}^{Rqst}	Man	Auxiliary	Auxiliary
11	Cancelled Maintenance Workers Requirements for E_k	$\dot{W}_{Mtcek}^{CaRqrd}$	Man/Time	Rate	Rate
12	CM/PM Costs Per Intervention for E_k	C_{CPmk}^{PerInt}	$	Input	Input
13	CM/PM MMA for E_k	$E_{CmPmk}^{\boldsymbol{WMatAv}}$	Dmnl	Auxiliary	Auxiliary
14	CM Intervention Period for E_k	t_{k}^{CmI}	Time	Auxiliary	Auxiliary
15	CM/PM Inventory Delay (ID) Period	t_{CPm}^{InvDel}	Time	Auxiliary	Auxiliary
16	CM Logistics Factor for E_k	f_{Ek}^{LogCM}	Dmnl	Input	Input
17	CM Workforce Pressure	W_{CM}^{Press}	Man	Auxiliary	Auxiliary
18	CM Efficiency for E_k	f_{Ek}^{TecCM}	Dmnl	Input	Input
19	CM/PM Intervention Duration for E_k	t_{CmPmk}^{IDur}	Time	Input	Input
20	CM/PM Maintenance Expense Rate for E_k	$\ddot{C}_{MCPmk}^{Exp}$	$/Time	Auxiliary	Auxiliary

Table B3 (continued): Quantity specification for the Maintenance sector

Quantity					
SN	**Description**	**Symbol**	**Dimension**	**Sector Type**	**System Type**
21	CM/PM Maintenance Frequency	f_{CPFrq}^{mtce}	Dmnl	Auxiliary	Auxiliary
22	CM/PM Maintenance Man-hour Required for E_k	t_{CPmk}^{WRqrd}	ManTime	Input	Input
23	CM/PM Maintenance Material Order Units	M_{MCPm}^{Ordr}	$	Auxiliary	Auxiliary
24	CM/PM Maintenance Workforce Required for E_k	W_{CmPmk}^{Rqrd}	Man	State	State
25	CM/PM Periodic Expense per Intervention	$\ddot{C}_{CPmk}^{IntEx}$	$/hour	Auxiliary	Auxiliary
26	CM/PM Periodic Costs per Intervention for E_k	$\ddot{C}_{CPmk}^{IntCst}$	$/hour	Auxiliary	Auxiliary
27	CM/PM Periodic Maintenance Workforce Met for E_k	$\dot{W}_{CmPmk}^{Met}$	Man/Time	Rate	Rate
28	CM/PM Periodic Maintenance Workforce Required for E_k	$\dot{W}_{CmPmk}^{Rqrd}$	Man/Time	Rate	Rate
29	CM/PM Periodic Personnel Request Met for E_k	$E_{CmPmk}^{MetRqst}$	Dmnl	Auxiliary	Auxiliary
30	CM/PM Personnel Request for E_k	E_{CmPmk}^{WRqst}	Dmnl	Auxiliary	Auxiliary
31	CM Recruitment. Decision	f_{RecCm}^{Dec}	Dmnl	Input	Input
32	CM/PM Total Costs per Intervention	C_{CPm}^{TotInt}	$	Auxiliary	Auxiliary
33	CM/PM Total Periodic Maintenance Expense per	C_{xCPm}^{MTot}	$\$/Month$	Input	Input
34	CM/PM Periodic Costs per Intervention	$\ddot{C}_{CPm}^{PrdInt}$	$	Auxiliary	Auxiliary
35	Constrained Maintenance Personnel Gap	W_{mtce}^{Cgap}	Man	Auxiliary	Auxiliary
36	Cumulative Downtime for E_k	t_{cumk}^{down}	Time	State	State
37	Cumulative Uptime for E_k	t_{cumk}^{Up}	Time	State	State
38	Decision for PM Recruitment	f_{RecPm}^{Dec}	Dmnl	Input	Input

Table B3 (continued): Quantity specification for the Maintenance sector

SN	Quantity Description	Symbol	Dimension	Sector Type	System Type
39	Decision for TA Recruitment	f_{RecTaM}^{Dec}	Dmnl	Input	Input
40	Degradation Rate for E_k	$\dot{E}_k^D$	1/Time	Rate	Rate
41	Degradation Level for E_k	E_k^D	Time	State	State
42	Degradation Reduction Rate for E_k	$\dot{E}_k^{DR}$	Time	Rate	Rate
43	Delayed Inventory	M_{Del}^{Inv}	$	State	State
44	Desired Maintenance Personnel Gap	W_{mtce}^{Dgap}	Man	Auxiliary	Auxiliary
45	Desired Maintenance Workforce	W_{mtce}^{Des}	Man	Auxiliary	Auxiliary
46	Desired PM Usage Period	t_{MPm}^{Usage}	Time	Auxiliary	Auxiliary
47	Desired TA Maintenance Usage Period	t_{MTa}^{Usage}	Time	Auxiliary	Auxiliary
48	Earliest PM Time	t_{Pm}^{Earlst}	Time	Auxiliary	Auxiliary
49	Equipment Maintenance Fund (EMF)	F_{Mtce}	$	State	State
50	Equipment Type (k) Periodic Downtime	$\dot{t}_k^{down}$	Time	Input	Rate
51	Expected Lead Time	t_{Exptd}^{lead}	Time	Input	Input
52	Expected no. of planned shutdowns	N_{Plan}^{sdwn}	Dmnl	Input	Input
53	Failure Probability for Equipment Type (k)	P_{Ek}^{Φ}	Dmnl	Auxiliary	Auxiliary
54	Frequency at which CM/PM Periodic Maintenance	f_{CmPmk}^{Met}	1/Time	Input	Input
55	Frequency at which TA Periodic Maintenance	f_{Tak}^{Met}	1/Time	Input	Input
56	Inactive Maintenance Workers	W_{mtce}^{Inact}	Man	State	State
57	Intervention Period for E_k	t_k^{Int}	Time	Auxiliary	Auxiliary
58	Inventory Arrival Rate	$\dot{M}_{Ordr}^{Out}$	$/hour	Rate	Rate
59	Inventory Lot Size for Order	M_{Lot}^{Ordr}	$	Auxiliary	Auxiliary

Table B3 (continued): Quantity specification for the Maintenance sector

SN	Description Quantity	Quantity Symbol	Dimension	Sector Type	System Type
60	Inventory Receiving Rate	$\dot{M}_{Hand}^{InvIn}$	$/hour	Rate	Rate
61	Inventory Order Rate	$\dot{M}_{Ordr}^{In}$	$/hour	Rate	Rate
62	Inventory on hand	M_{Hand}^{Inv}	$	Input	State
63	Inventory Utilisation Rate	$\dot{M}_{Hand}^{InvOut}$	$/hour	Rate	Rate
64	Inventory Usage Efficiency Factor	f_{Usage}^{InvEff}	Dmnl	Input	Input
65	Manpower and Material Availability for E_k	E_k^{WMatAv}	Dmnl	Auxiliary	Auxiliary
66	Manpower Mode Requested for E_k	E_{Modek}^{WRqst}	Dmnl	Auxiliary	Auxiliary
67	Maintenance Action for E_k	E_{Mtcek}^{Act}	Dmnl	Input	Auxiliary
68	Maintenance Assignment Delay for E_k	t_{MAss}^{Strt}	Time	Input	Input
69	Maintenance Assignment Delay Period for E_k	t_{MAss}^{Strt*}	Time	Auxiliary	Auxiliary
70	Maintenance Assignment Completion Delay for E_k	t_{MAss}^{Done}	Time	Auxiliary	Auxiliary
71	Maintenance Assignment Completion Delay Period for	t_{MAss}^{Done*}	Time	Input	Input
72	Maintenance Fund capability	W_{MFund}^{Cap}	Man	Auxiliary	Auxiliary
73	Maintenance Completed for E_k	E_{Mtcek}^{Done}	Dmnl	Input	Auxiliary
74	Maintenance Effectiveness	f_{mtce}^{eff}	Dmnl	Input	Input
75	Maintenance Labour Cost	$\ddot{C}_{Mtce}^{Lab}$	$/Time	Output	Auxiliary
76	Maintenance Labour Wage Rate	C_{mtce}^{Wage}	$/ManTime	Input	Input
77	Maintenance Manpower Availability (MMA) for E_k	E_{Mtcek}^{WAv}	Dmnl	Input	Auxiliary
78	Maintenance Mode for E_k	E_{Mtcek}^{Mode}	Dmnl	Auxiliary	Auxiliary
79	Maintenance Operators Fund	B_{MP}	$	Input	Auxiliary
80	Maintenance Personnel Gap	W_{mtce}^{gap}	Man	Auxiliary	Auxiliary
81	Maintenance Personnel Inflow	$\dot{W}_S^{Hire}$	Man/Time	Rate	Rate

Table B3 (continued): Quantity specification for the Maintenance sector

Quantity					
SN	**Description**	**Symbol**	**Dimension**	**Sector Type**	**System Type**
82	Maintenance Personnel Perceived Active and	W_{Perck}^{Uvail}	Man	Auxiliary	Auxiliary
83	Maintenance Personnel Perceived Active and	W_{Perc}^{Uvail}	Man	Auxiliary	Auxiliary
84	Maintenance Personnel Outflow	$\dot{W}_{S}^{Fire}$	Man/Time	Rate	Rate
85	Maintenance Personnel Outflow Factor	f_{mtce}^{Fire}	1/Time	Input	Input
86	Maintenance Process for E_k	E_{Prock}^{Mtce}	Time	State	State
87	Maintenance Recruitment Delay	t_{mtce}^{DRcrit}	Time	Auxiliary	Auxiliary
88	Maintenance Recruitment Delay Period	$t_{Mtce}^{DRcrit*}$	Time	Input	Input
89	Maintenance Recruitment In Process	W_{Proc}^{Rcrit}	Dmnl	Auxiliary	Auxiliary
90	Maintenance Recruitment Rate	$\dot{W}_{S}^{Rcrit}$	Man/Time	Rate	Rate
91	Maintenance Resource Availability Factor	f_{mtce}^{ReAv}	Dmnl	Input	Input
92	Maintenance Rate for E_k	$\dot{E}_{k}^{Mtce}$	OpsTime/Ti	Rate	Rate
93	Maintenance Workers Request Dun (RD) for E_k	E_{Dunk}^{WRqst}	Man	State	State
94	Maintenance Workers Request Signal Start for E_k	$\dot{E}_{DStrtk}^{WRqst}$	Man/Time	State	State
95	Maintenance Workers Request Signal End for E_k	$\dot{E}_{DEndk}^{WRqst}$	Man/Time	Auxiliary	Auxiliary
96	Maintenance Workforce Assignment Process	S_{mtce}^{WAss}	Dmnl	Auxiliary	Auxiliary
97	Material Usage Rate for E_k	$\ddot{M}_{Matk}^{Usage}$	\$/hour	Auxiliary	Auxiliary
98	Maximum Maintenance Workforce No. Allowable	W_{MtceS}^{Max}	Man	Input	Auxiliary
99	Minimum Maintenance Workforce No. Allowable	W_{MtceS}^{Min}	Man	Input	Auxiliary

Table B3 (continued): Quantity specification for the Maintenance sector

SN	Description	Symbol	Dimension	Sector Type	System Type
100	Number of Maintenance Workers Request for E_k	W_{Mtcek}^{Rqst}	Man/Time	Input	Input
101	Periodic Material Usage Rate	$\ddot{M}_{Mat}^{Usage}$	$/hour	Input	Input
102	Periodic TA Costs per Intervention for E_k	$\ddot{C}_{Tak}^{IntCst}$	$/hour	Auxiliary	Auxiliary
103	Periodic TA Expense per Intervention for E_k	$\ddot{C}_{Tak}^{IntEx}$	$/Time	Auxiliary	Auxiliary
104	Periodic Uptime for E_k	$\dot{t}_k^{Up}$	OpsTime /Time	Rate	Rate
105	Personnel Gap (Regular Maintenance)	W_{MReg}^{gap}	Man	Auxiliary	Auxiliary
106	Personnel Gap (Non-regular Maintenance)	W_{MNReg}^{gap}	Man	Auxiliary	Auxiliary
107	Perceived Personnel Available for Maintenance Service	W_{MPerc}^{Avail}	Man	Auxiliary	Auxiliary
108	Personnel Request for E_k	E_k^{WRqst}	Dmnl	Auxiliary	Auxiliary
109	Personnel Required for CM	W_{Cm}^{Rqrd}	Man	Auxiliary	Auxiliary
110	Personnel Required for Maintenance	W_{Mtce}^{Rqrd}	Man	Auxiliary	Auxiliary
111	Personnel Required for PM Maintenance	W_{Pm}^{Rqrd}	Man	Auxiliary	Auxiliary
112	Personnel Recruitment for TA Maintenance	W_{TaM}^{Rqrd}	Man	Auxiliary	Auxiliary
113	Personnel for Retrenchment	W_S^{Fire}	Man	Auxiliary	Auxiliary
114	Plant Operating Period (POP)	t^*	Time	Input	Auxiliary
115	Plant Useful Life	P_L	Time	Input	Input
116	Plant Design Capacity (PDC)	P_{DC}	MTPA	Auxiliary	Auxiliary
117	Planned/ Unplanned Maintenance for E_k	$E_{Mtcek}^{P\_Up}$	Dmnl	Auxiliary	Auxiliary
118	PM Logistics Factor for E_k	f_{Ek}^{LogPM}	Time	Input	Input
119	PM Maintenance Expense Rate	$\ddot{C}_{MCPm}^{Exp}$	$/Time	Auxiliary	Auxiliary

Table B3 (continued): Quantity specification for the Maintenance sector

SN	Description Quantity	Quantity Symbol	Dimension	Sector Type	System Type
120	PM Efficiency Factor for E_k	f_{Ek}^{TecPM}	Time	Input	Input
121	PM Request Window for E_k	t_{PMk}^{ReqWin}	Time	Auxiliary	Auxiliary
122	PM request Factor	f_{PMk}^{Req}	Dmnl	Input	Input
123	PM Personnel Pre-Request for E_k	E_{PMk}^{PreReq}	Dmnl	Auxiliary	Auxiliary
124	PM Personnel Request	E_{Pm}^{WRqst}	Dmnl	Auxiliary	Auxiliary
125	PM Action for E_k	E_{Mtcek}^{PmAct}	Dmnl	Auxiliary	Auxiliary
126	PM Action Signal for E_k	E_{Signk}^{PmAct}	Dmnl	Auxiliary	Auxiliary
127	PM Intervention Period for E_k	t_k^{PmI}	Time	Auxiliary	Auxiliary
128	PM Recruitment Countdown for E_k	t_{PmCdnk}^{WRec}	Time	Auxiliary	Auxiliary
129	Time To PM (TTPM) Threshold for E_k	t_{TTPmk}^{Thr}	Time	Input	Input
130	PM Workforce Pressure	W_{Pm}^{Press}	Man	Auxiliary	Auxiliary
131	PM Workforce Recruitment Countdown	t_{PmCdn}^{WRec}	Time	Auxiliary	Auxiliary
132	Random Failure Probability	$P_{Ek}^{\Phi\mathrm{r}}$	Dmnl	State	State
133	Reorder Point	M_{Point}^{Rordr}	$	Auxiliary	Auxiliary
134	Restart Rate for E_k	$\dot{E}_k^{Rsrt}$	OpsTime/Ti	Rate	Rate
135	Random Failure Probability Parameter for E_k	$f_{Ek}^{\Phi\mathrm{r}}$	Dmnl	Auxiliary	Auxiliary
136	Safety Inventory Stock	M_{Safe}^{Inv}	$	Auxiliary	Auxiliary
137	Spare availability	E_S^{SpAv}	Dmnl	Auxiliary	Auxiliary
138	Spare Availability for CM/PM	E_{CmPm}^{SpAv}	1/hour	Auxiliary	Auxiliary
139	Spare Availability for TA Maintenance	E_{Ta}^{SpAv}	1/hour	Auxiliary	Auxiliary
140	System Availability	A_S	Dmnl	Output	Output
141	System Availability Status	A_S^S	Dmnl	Output	Auxiliary
142	System CM Intervention Time	t_S^I	Time	Auxiliary	Auxiliary
143	System Failure	Φ_S	Dmnl	Auxiliary	Auxiliary

Table B3 (continued): Quantity specification for the Maintenance sector

SN	Description	Symbol	Dimension	Sector Type	System Type
144	System Downtime Accumulation Rate	$\dot{t}_S^d$	OpsTime/Time	Rate	Rate
145	System Expected Life	L_s	Time	State	State
146	System Material Usage Rate	C_S^{Use}	$/hour	Auxiliary	Auxiliary
147	System Restart After TA Maintenance Done	$\dot{E}_{Ta}^{Rsrt}$	Dmnl	Auxiliary	Auxiliary
148	System Usage Rate	$\dot{t}_S^U$	OpsTime/Time	Rate	Rate
149	System Unplanned Failure (UF) event	E_S^{Uf}	Dmnl	Auxiliary	Auxiliary
150	TA Costs per Intervention	C_{Ta}^{PerInt}	$	Input	Auxiliary
151	TA Costs per Intervention for E_k	C_{Tak}^{PerInt}	$	Input	Input
152	TA MMA for E_k	$E_{TAk}^{\boldsymbol{WMatAv}}$	Dmnl	Auxiliary	Auxiliary
153	TA Maintenance Done for E_k	t_{Donek}^{Ta}			
154	TA Intervention Period for E_k	t_k^{TaI}	Time	Auxiliary	Auxiliary
155	TA Inventory Delay (ID) Period	t_{Ta}^{InvDel}	Time	Auxiliary	Auxiliary
156	TA Logistics Factor for E_k	f_{Ek}^{LogTA}	Time	Input	Input
157	TA Efficiency for E_k	f_{Ek}^{TecTA}	Time	Input	Input
158	TA Maintenance Action for E_k	E_{Mtcek}^{TaAct}	Dmnl	Auxiliary	Auxiliary
159	TA Maintenance Action Signal	E_{Sign}^{TaAct}	Dmnl	Auxiliary	Auxiliary
160	TA Maintenance Interval	t_{Mtce}^{Ta}	Time	Auxiliary	Auxiliary
161	TA Maintenance Man-hour Required for E_k	t_{Tak}^{Wrqrd}	Time	Input	Input
162	TA Maintenance Cost Fraction	f_{Ta}^{mtce}	Dmnl	Input	Input
163	TA Maintenance Duration for E_k	t_{Tak}^{IntDur}	Time	Input	Input
164	TA Maintenance Frequency	f_{TaFrq}^{mtce}	Dmnl	Auxiliary	Auxiliary
165	TA Maintenance Expense Rate for E_k	$\ddot{C}_{MTak}^{Exp}$	$/Time	Auxiliary	Auxiliary
166	TA Maintenance Expense Rate	$\ddot{C}_{MTa}^{Exp}$	$/Time	Auxiliary	Auxiliary

Table B3 (continued): Quantity specification for the Maintenance sector

Quantity					
SN	**Description**	**Symbol**	**Dimension**	**Sector Type**	**System Type**
167	TA Maintenance Material Order Units	M_{MTa}^{Ordr}	$	Auxiliary	Auxiliary
168	TA Maintenance Time	t_{mtce}^{TA}	Time	Input	Input
169	TA Maintenance Workforce Pressure	W_{Ta}^{Press}	Man	Auxiliary	Auxiliary
170	TA Maintenance workers Request for E_k	E_{Tak}^{Rqst}	Dmnl	Auxiliary	Auxiliary
171	TA Maintenance Workforce Required for E_k	W_{Tak}^{Rqrd}	Man	State	State
172	TA Maintenance Initiation	t_{Initk}^{TA}	OpsTime/Time	Rate	Rate
173	TA Periodic Maintenance Workforce Requirement Met for E_k	$\dot{W}_{Tak}^{Met}$	Man/Time	Rate	Rate
174	TA Periodic Maintenance Workforce Required for E_k	$\dot{W}_{Tak}^{Rqrd}$	Man/Time	Rate	Rate
175	TA Periodic Personnel Request Met for E_k	$E_{Tak}^{MetRqst}$	Dmnl	Auxiliary	Auxiliary
176	TA Personnel Pre-Request for E_k	E_{Tak}^{PreReq}	Dmnl	Auxiliary	Auxiliary
177	TA Personnel Request for E_k	E_{Tak}^{WRqst}	Dmnl	Auxiliary	Auxiliary
178	TA Personnel Request	E_{Ta}^{WRqst}	Dmnl	Auxiliary	Auxiliary
179	TA Total Costs per	C_{Ta}^{TotInt}	$	Auxiliary	Auxiliary
180	TA Periodic Costs per Intervention	$\ddot{C}_{Ta}^{PrdInt}$	$/hour	Auxiliary	Auxiliary
181	TA Total Periodic Maintenance Expense per	C_{xTa}^{MTot}	$\$/Month$	Input	Input
182	Time To PM (TTTA) Threshold for E_k	t_{TTTak}^{Thr}	Time	Input	Input
183	TA Workforce Recruitment Countdown	t_{TaCdn}^{WRec}	Time	Input	Auxiliary
184	Time to TA Maintenance	t_k^{ToTa}	Time	Input	State
185	Time to PM for E_k	t_k^{ToPm}	Time	Input	Auxiliary

Table B3 (continued): Quantity specification for the Maintenance sector

SN	Description	Symbol	Dimension	Sector Type	System Type
		Quantity			
186	Time to PM	t^{ToPm}	Time	Input	Input
187	Total CM Man Power Request	W_{CmTot}^{Rqst}	Man	Auxiliary	Auxiliary
188	Total Maintenance Cost for E_k	C_{Ek}^{mtce}	$	Auxiliary	Auxiliary
189	Total Maintenance Personnel in Service	W_{MSrv}^{Tot}	Man	Auxiliary	Auxiliary
190	Total Maintenance Manpower Required	W_{Mrqd}^{Tot}	Man	Auxiliary	Auxiliary
191	Total Periodic Cost for E_k	C_{Totk}^{mtce}	$/hour	Auxiliary	Auxiliary
192	Total PM Man Power Request	W_{PmTot}^{Rqst}	Man	Auxiliary	Auxiliary
193	Total PM Man Power Required	W_{PMrqd}^{Tot}	Man	Auxiliary	Auxiliary
194	Total Periodic Spare Parts Costs	C_{TotS}^{mtce}	$/hour	Auxiliary	Auxiliary
195	Total Process Downtime	t_S^d	Time	State	State
196	Total Requested Maintenance Labour	W_{MtceS}^{Rqstd}	Man	Auxiliary	Auxiliary
197	Total System Usage	t_S^U	Time	State	State
198	Total TA Man Power Requirement	W_{Tarqd}^{Tot}	Man	Auxiliary	Auxiliary
199	Unplanned Failure (UF) event for E_k	E_k^{Uf}	Dmnl	Auxiliary	Auxiliary
200	Unplanned Failure Signal for E_k	E_{Signk}^{Uf}	Dmnl	Auxiliary	Auxiliary
201	UF Personnel Request for E_k	E_{Ufk}^{WRqst}	Dmnl	Auxiliary	Auxiliary
202	Unplanned Maintenance Action for E_k	E_{Mtcek}^{UAct}	Dmnl	Auxiliary	Auxiliary
203	Upper Lead Time Tolerance	f_{Upper}^{TLead}	Dmnl	Input	Input
204	Used Material (TA)	M_{MatTa}^{Use}	$	State	State
205	Used Material (TA) In Flow	M_{MatTa}^{UseIn}	$/hour	Rate	Rate
206	Used Material (TA) OutFlow	M_{MatTa}^{UseOut}	$/hour	Rate	Rate
207	Weibull Shape parameter for E_k	β_{Ek}	Dmnl	Input	Input

Table B3 (continued): Quantity specification for the Maintenance sector

	Quantity				
SN	**Description**	**Symbol**	**Dimension**	**Sector Type**	**System Type**
208	Weibull Scale parameter for E_k	η_{Ek}	Time	Input	Input
209	Workforce for Maintenance Recruitment	W_S^{Rcrit}	Man	State	State

APPENDIX C

Derived equations from the formulation of the SD-LNG-LCC plant economic viability analysis

(1) Unit LNG Production Cost

$$C_{Prod}^{UnitLNG} = \frac{C_{LCC}^{Tot}}{V_{Order}^{ship} f_{LNG}^{mmBTU}} \qquad (B1)$$

(2) Total Revenue

$$G_{Rev}^{Tot} = \left(\int_{G_{Rev}^{Tot}\{t=t^*\}}^{G_{Rev}^{Tot}\{t=T^*\}} \dot{G}_{Rev} dt \right) + G_{Rev}^{Tot}\{t = t^*\} \qquad (B2)$$

$$\dot{G}_{Rev} = \ddot{G}_{Rev} = C^{LNG} \dot{V}_{Order}^{shipBTU} \qquad (B3)$$

$$\dot{V}_{Order}^{shipBTU} = \dot{V}_{Order}^{ship} f_{LNG}^{mmBTU} \qquad (B4)$$

(3) Discounted Total Profit

$$G_{LNG}^{Disc} = \left(\int_{t=t^*}^{t=T^*} \dot{G}_{LNG}^{Disc} dt \right) + G_{LNG}^{Disc}\{t = t^*\} \qquad (B5)$$

$$\dot{G}_{LNG}^{Disc} = \ddot{G}_{LNG}^{Disc} = \frac{\ddot{G}_{LNG}}{f^{Disc}} \qquad (B6)$$

$$\ddot{G}_{LNG} = \dot{G}_{Rev} - \dot{C}_{LCC}^{Tot} \qquad (B7)$$

$$f^{Disc} = \left(1 + \ddot{R}^{Disc}\right)^{t^*} \qquad (B8)$$

$$\ddot{R}^{Disc} = \frac{r^{Disc}}{f_{Yr}^{POP}} \qquad (B9)$$

(4) Pay Back Period

$$t_{Back}^{Pay} = \frac{\hat{F}_{EX}^{TC} t^*}{G_{Cash}^{NPV} f_{Yr}^{POP}} \qquad \{t^* \geq 0; t^* mod f_{Yr}^{POP} = 0\} \qquad (B10)$$

$$G_{Cash}^{NPV} = \left(\int_{t=t^*}^{t=T^*} \dot{G}_{Cash}^{NPV} dt\right) + G_{Cash}^{NPV}\{t = t^*\} \qquad (B11)$$

$$\dot{G}_{Cash}^{NPV} = \frac{\left(\ddot{G}_{LNG} + \dot{E}_{xDP}\right)}{f^{Disc}} \qquad (B12)$$

(5) Return On Investment

$$P_{ROI}^{NPV} = \frac{G_{LNG}^{Disc} f_{Yr}^{POP}}{C_{Capinv}^{NPV} t^*} \qquad \{t^* \geq 0; t^* mod f_{Yr}^{POP} = 0\} \qquad (B13)$$

$$C_{Capinv}^{NPV} = \left(\int_{t=t^*}^{t=T^*} \dot{C}_{Capinv}^{NPV} dt\right) + C_{Capinv}^{NPV}\{t = t^*\} \qquad (B14)$$

$$\dot{C}_{Capinv}^{NPV} = \frac{\left(\dot{F}_{EX}^{C} + \dot{E}_{xD}^{Less} + \dot{C}_{CF}^{Intrst}\right)}{f^{Disc}} \qquad (B15)$$

(6) Breakeven Quantity

$$\mathrm{V}_{Even}^{Break} = V_{Order}^{ship} \qquad \left\{G_{Rev}^{Tot} = C_{Capinv}^{NPV}\right\} \qquad (B16)$$

(7) Breakeven Period

$$t_{Even}^{Break} = t^* \qquad \left\{G_{Rev}^{Tot} = C_{Capinv}^{NPV}\right\} \qquad (B17)$$

APPENDIX D

EQUIPMENT MAINTENANCE PARAMETER ESTIMATION

TABLE D1: Failure distribution and unit work force estimation

A	B	C	D	E	F	G	H	I	J	K	L	M
Equipment [E(k)]	No of E(k) Units	No. of Failures	Obs. period (hrs)	Repair time (hrs)	Repair time (Manhrs)	No of Failure Modes	TA Mtce. time (hrs)	Failure Rate (Per hr)	Shape Param.	Scale Parameter (Early Life)	Scale Parameter (Useful Life)	Scale Parameter Wear out Life
Compressor (CT1)	1	377.18	1.00E+06	9.00	27.80	23	207.00	3.77E-04	1.20	2651.00	3181.50	2121.30
Compressor (CT2)	6	650.19	1.00E+06	18.90	30.20	38	718.20	6.50E-04	1.20	1537.80	1845.61	1230.16
Gas Turbine Driver (GTD)	4	2000	1.00E+06	19.40	37.70	25	485.00	2.00E-03	1.20	499.68	599.47	399.89
MfHE	4	139.66	1.00E+06	48.00	96.00	7	336.00	1.40E-04	1.20	7160.05	8592.04	5728.03
MCHE	2	9.7	1.00E+06	40.00	70.00	7	280.00	9.70E-06	1.20	7715.32	9258.53	6172.10
GST1 (>300M^3)	1	4905.32	1.00E+06	4.50	6.30	17	76.50	4.91E-03	1.20	204.13	245.27	163.00
GST2 (<300m^3)	1	305.04	1.00E+06	8.20	9.80	15	123.00	3.05E-04	1.20	3278.38	3934.21	2622.50
Valves	1	54.67	1.00E+06	6.00	7.50	25	150.00	5.47E-05	1.20	18291.60	21950.07	14633.09
Others	1	83.65	1.00E+06	21.30	30.50	10	213.00	1.40E-04	1.20	7142.51	8570.71	5714.31
GTHS	3	212.55	1.00E+06	52.90	97.80	6	317.40	2.13E-04	1.20	4705.06	5645.76	3764.24
Piping (PPNG)	1	0.182	1.00E+06	6.00	9.70	10	60.00	2.81E-04	1.20	3560.22	4272.41	2848.01
Ships (TRPN)	12	–	--	5.00	10.00	10	50.00	7.27E-03	1.20	137.87	165.29	110.44

TABLE D1 (Continued): Failure distribution and unit work force estimation

A	N	O	P	Q	R	S	T	U
Equipment [E(k)]	Mean Time to PM			CM/PM Man power [F/E]	TA Mtce. (Manhr) [F*G]	TA Mtce. Man power [R/H]	Manhr/ MTPA (CMPM) [(F*B)/4.5]	Manhr/ MTPA (TA) [(R*B)/4.5]
	Early Life	Useful Life [1.2*N]	Wear out Life [0.8*N]					
Compressor (CT1)	3481	4177	2785	4	639.40	4	7	143
Compressor (CT2)	2019	2423	1615	2	1147.60	2	42	1536
Gas Turbine Driver (GTD)	656	787	525	2	942.50	2	36	840
MfHE	9400	11280	7520	2	672.00	2	88	600
MCHE	10129	12155	8103	2	490.00	2	32	218
GST1 (>300M^3)	268	322	214	2	107.10	2	2	24
GST2 (<300m^3)	4304	5165	3443	2	147.00	2	3	33
Valves	24014	28817	19211	2	187.50	2	2	42
Others	9377	11252	7502	2	305.00	2	7	68
GTHS	6177	7412	4942	2	586.80	2	66	393
Piping (PPNG)	4674	5609	3739	2	97.00	2	3	22
ships (TRPN)	181	217	145	2	100.00	2	36	276

TABLE D2: Equipment maintenance cost and intervention estimation

A	B	C	D	E	F	G	H	I	J	K
Equipment [E(k)]	**Equipment Type (Specification)**	**E(k) Unit cost (EUC) {$/4.5 MPTA}**	**No of E(k) Units**	**EUC {$/ MPTA} [C/4.5]**	**Train(s) Capacity**	**E(k) Mtce. Fraction (% of purchase cost)**	**Estimated replacement rate {$/ MPTA} [E*G]**	**Plant life {yr}**	**Repair time {hr}**	**Total mtce. Cost {$} [D*F*H*I]**
CT1	Type 1 (3.5MW)	3980400	1	884533.33	22.00	0.05	44226.67	21	9	20432720
CT2	Type 2 (11MW)	9969600	2	2215466.67	22.00	0.05	110773.33	21	18.9	102354560
CT2	Type 4 (21.5 M'	17418900	1	3870866.67	22.00	0.05	193543.33	21	18.9	89417020
CT2	Type 5 (43 MW	37795200	3	8398933.33	22.00	0.05	419946.67	21	18.9	582046080
GTD	50 MW	35805000	4	7956666.67	22.00	0.05	397833.33	21	19.4	735196000
MfHE		42956700	4	9545933.33	22.00	0.05	477296.67	21	48	882044240
MCHE	Type 1	74307000	1	16512666.67	22.00	0.05	825633.33	21	40	381442600
MCHE	Type 2	11346000	1	2521333.33	22.00	0.05	126066.67	21	40	58242800
GST1	Type 1 (>=300m	2964840	1	658853.33	22.00	0.05	32942.67	21	4.5	15219512
GST2	Type 2 (<300m3	917910	1	203980.00	22.00	0.05	10199.00	21	8.2	4711938
Valves	All types	2571450	1	571433.33	22.00	0.05	28571.67	21	6	13200110
OTHERS	Sensors, Fire/ gas detectors, pumps	48006600	1	10668133.33	22.00	0.05	533406.67	21	25.7	246433880
GSTH		186000	3	41333.33	22.00	0.05	2066.67	21	52.9	2864400
Piping		84011550	1	18669233.33	22.00	0.05	933461.67	21	6	431259290
TRPN		217975455	12	9907975.21	22.00	0.05	495398.76	21	5	228874227

TABLE D2 (Continued): Equipment maintenance cost and intervention estimation

A	B	L	M	N	O	P	Q
Equipment [E(k)]	Equipment Type (Specification)	MTTInt (PM) {hr}	MTTInt (TA) {hr} [5*12*28*24]	Tot. No. of TA Int. [(I*12*28*24)/M]	Total TA duration {hr}	Total PM duration {hr}	Tot. No. of PM Int. [{(I*12*28*24)-O}/L]
CT1	Type 1 (3.5MW)	3481	40320	4	36.00	161244.00	46
CT2	Type 2 (11MW)	2019	40320	4	75.60	161204.40	80
CT2	Type 4 (21.5 MW)	2019	40320	4	75.60	161204.40	80
CT2	Type 5 (43 MW)	2019	40320	4	75.60	161204.40	80
GTD	50 MW	656	40320	4	77.60	161202.40	246
MfHE		9400	40320	4	192.00	161088.00	17
MCHE	Type 1	10129	40320	4	160.00	161120.00	16
MCHE	Type 2	10129	40320	4	160.00	161120.00	16
GST1	Type 1 (>=300m3	268	40320	4	18.00	161262.00	602
GST2	Type 2 (<300m3)	4304	40320	4	32.80	161247.20	37
Valves	All types	24014	40320	4	24.00	161256.00	7
OTHERS	Sensors, Fire/ gas detectors, pumps	9377	40320	4	85.20	161194.80	17
GSTH		6177	40320	4	211.60	161068.40	26
Piping		4674	40320	4	24.00	161256.00	35
TRPN		181	40320	4	20.00	161260.00	891

APPENDIX E

DETAILS OF PORT DISTANCES AND DAILY PORT CHARGES FOR LNGFWA PRODUCT BUYER GROUPS

Table E1: port distances and daily port charges for LNGFWA product buyer groups

Buyer group (G)	**Buyer group name**	**Average laden load travel distance $\left(D_{TripGt^*}^{RShip}\right)$ [Nautical Miles]**	**Destination port charges $\left(C_{Dest}^{Port}\right)$ [$/day]**	**Source port charge $\left(C_{Dest}^{Port}\right)$ [$/day]**
1	Africa	5,525	30,000	61,000
2	Europe	4199	150,000	
3	Japan-Korea Market	13,304	76,000	
4	Middle East	8,494	30,000	
5	North America	6,404	110,000	
6	South America	4,510	55,500	
7	South Asia	8,462	175,000	