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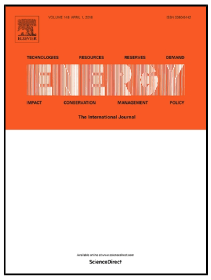

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A Stochastic Integrated Planning of Electricity and Natural Gas Networks for Queensland, Australia Considering High Renewable Penetration

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Abstract- This study develops a long-term integrated planning approach to electricity and gas aiming at economically optimizing the 2030's investments of both networks while considering new policies towards future clean energy. A static stochastic cost minimization model is formulated, which takes into account the short-term uncertainties of renewable power, i.e. wind and utility-scale solar photovoltaic (PV) as well as the long-term uncertainties of load growth and gas price. The equivalent networks of both electricity and gas are driven to accurately capture their existing supplies and transmission networks. In addition, the integrated planning model allows determining the location of new power plants and gas supply facilities with their optimized capacities, as well as new transmission lines and pipelines. An extension of the proposed scheme is considered to accommodate higher penetrations of renewable energy and assess their impacts on both systems. The proposed model is applied to the state of Queensland in Australia, which is a prime example of a region actively integrating electricity and gas.

***Index Terms*— Electricity network, gas network, high renewable energy penetration, long-term integrated planning, stochastic optimization.**

1. INTRODUCTION

1.1. Background, Motivation and Approach

Environmental concerns have caused governments worldwide to establish new policies to reduce carbon emissions, which have encouraged a shift towards lower carbon technologies. In electric power systems, this movement has been observed with the

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ascension of renewable technologies and natural gas. A report from International Energy Agency [1] has shown that the share of natural gas in the world electricity generation has grown from 12.1% in 1973 to 21.6% in 2014 while renewable sources share has increased from 0.6% to 6.3% in the same period. Renewable energy sources are clean and provide zero emission energy while natural gas is more economically competitive in a carbon-constrained economy, though it involves a level of emission.

Queensland, the North Eastern state of Australia, is an example of a region in which the growth of these technologies has been noticed over the past decade. To support the shift from coal to less intensive carbon technologies, the Australian Government has set a series of policy instruments intended to significantly reduce Australia's greenhouse gas emissions in long-term. The first policy, i.e. Mandatory Renewable Energy Target (MRET) in Australia, has introduced a target of 20% renewable energy by 2020 [2]. This policy has encouraged the development of both small-scale renewable installations (Small-scale Renewable energy scheme-SRET) and large-scale renewable installations (Large-scale Renewable Energy Target-LRET). While the SRET has significantly affected the solar rooftop PV output in Queensland, it is expected that the LRET will develop quickly other renewable sources in the state in the near future. In addition, a scheme to develop natural gas, i.e. Queensland Gas Scheme, has boosted the natural gas industry and led the state to even export Liquefied Natural Gas (LNG) [3]. Furthermore, the Queensland's Government is investigating possible pathways towards a 50% renewable energy target by 2030, which will significantly affect its future electricity generation mix [4].

Given the strong commitment of world nations to reduce greenhouse gas emissions, it is imperative to consider the significant challenges imposed by both renewable sources and natural gas to traditional energy planning models. Renewable sources have a degree of uncertainty due to their variable nature in production, which affects the planning and operation of electricity systems. An increasing share of gas-fired generation results in a stronger interconnection between gas and electricity networks, which might affect the overall operation and the long-term planning of the natural gas network. In an energy system with large penetration of gas power plants, a gas shortage not only constrains the gas demand but could also lead to electricity disruption [5]. In addition, economic aspects of gas, such as gas price and gas contracts, could also affect the natural gas supply adequacy and the long-term expansion planning of electricity generation [6]. The standalone planning of electricity and natural gas networks disregards operational and security issues and does not address the interaction between them [7]. In this context, performing an integrated planning model of electricity and gas allows the inclusion of economic and physical aspects of gas while optimally managing the long-term investment decisions in both networks.

Accordingly, this study develops an integrated planning approach for electricity and gas while considering the effects of new policies towards less-intensive carbon technologies. The proposed approach adopts a long-term timeframe intending to economically optimize future generation investment decisions while deciding their locations in the equivalent networks. The potential impacts of high penetration of intermittent resources on the integrated planning are evaluated, as well as the effects of other environmental constraints, i.e. carbon cost, renewable energy target and coal-based generation. Short and long-term uncertainties associated with wind and utility-scale PV power generation, load growth and gas prices are considered by formulating a two-stage stochastic programming approach. The problem is solved using General Algebraic Modeling System (GAMS) and is applied to a realistic case study of Queensland, Australia.

1.2. Literature review and Contributions

There are a number of studies in the literature exploring the expansion planning of electricity and gas networks individually. These investigations can be divided according to the planning horizon, i.e. operational planning models or long-term planning [8]. The operational planning considers a timeframe of few months to a year such as in [9] but disregards investments decisions in the long term. Long-term planning models have a timeframe of years to decades. Studies on stand-alone planning of electricity system, disregarding the interaction with a natural gas network are described as follow. They mostly have a deterministic approach, which disregards the impact of uncertain parameters in the future planning. While the investments in new generation plants are performed from the market operator point of view in [10], authors in [11] assess it from the generation companies (GENCOs) viewpoint. In [12], a sensitivity analysis is performed to investigates the impacts of rooftop PV penetration and gas price on the generation decisions. Some investigations have a stochastic approach, which accounts for the effects of uncertainties in the long-term electricity planning. A stochastic analysis to derive the optimal long-term energy mix is illustrated for Queensland case study in [13], the Australian NEM case study in [14] and Indonesia in [15]. In [16], a model is formulated to manage greenhouse gas (GHG) emissions in the electricity sector while in [17], the variable nature of renewable energy is assessed but without exploring the natural gas network. Natural gas planning models has also been assessed individually. In [18], optimal gas production for Queensland (QLD), Australia is evaluated, a decision support system for gas operation is presented in [19] .

Load and gas forecasting is important in long-term planning since it affects the infrastructure expansion of generation and transmission. There are some studies in the literature that address this topic. Authors in [20] develop a regression model using different historical data types to forecast the electrical consumption in the long-term. Reference [21] proposes a decomposition scheme to make long-term forecasts for the electricity sector. Authors in [22], assess the effects of demand side management on the electricity consumption forecasting accuracy. The state of the art and different methods used in the literature for forecasting natural gas consumption are presented in [23]. In Australia, long-term load and gas forecasting are performed by the Australian Energy Market Operator (AEMO) and utilities. Forecasting models for long-term load demand [24] and natural gas demand [25] are performed annually to adjust to socio-economic indicators. While our work's focus is beyond developing forecasting methods, our study indeed uses the existing forecasts by AEMO.

A limited number of studies conduct an integrated approach considering the expansion of both electricity and natural gas networks. Some investigations only assess the operation of both networks in the short-term timeframe disregarding the long-term investment decisions for these networks. These studies mainly consider operational challenges such security of the system [26], generation scheduling [27], security-constrained unit commitment [28], and the impact of wind power variability on both systems [29].

Long-term integrated planning models are developed considering either static or dynamic expansion strategies. The static approach considers a single investment decision in the planning horizon, while the dynamic (multistage) approach includes multiple investment decisions at different stages throughout the planning horizon [30]. A static mathematical approach to integrated planning is formulated in [6], which considers expansion of electricity and gas systems in a conventional way without modeling renewable energy resources. Dynamic long-term integrated planning models are described as follows. In [5], an integrated planning model of electricity and gas for the Great Britain is developed. The proposed model considers the low-emission scenarios while disregarding the uncertainty of renewable energy production. Authors in [31] propose a deterministic model to formulate a multi-area, multi-stage integrated planning approach for conventional electricity and gas systems. With the aim of maximizing the social welfare, authors in [32] propose a mathematical programming approach which only considers the uncertainties of the system load and market price in the given integrated planning model and assesses it using an IEEE test system. A new model is provided in [33] which validates the security of the integrated planning through a least-cost master investment decomposition model. Reference [34] evaluates low carbon scenarios for Great Britain electricity and gas systems while investigating the impact of converting part of gas demand to electricity demand.

From the above discussion, it can be emphasized that the majority of existing integrated planning models do not take into account the impacts of renewable energy resources. Further, the available models mostly formulate deterministic approaches disregarding uncertainties faced by both systems. Accordingly, the key contributions of this study are summarized as:

1. To develop a comprehensive long-term integrated planning approach of electricity and gas through which both long-term uncertainties (load growth and gas price) and short-term uncertainties (renewable energy production) are considered in the proposed stochastic programming approach.
2. To perform a realistic case study of Queensland, in which the electricity network and gas pipelines of this state are accommodated developing their equivalent networks.

3. To assess the impacts of high renewable energy penetration and different environmental constraints on the long-term electricity and gas integrated planning.

The rest of the study is structured as follows. Section 2 describes the mathematical formulation of the proposed integrated planning model. The Queensland case study and results are provided in Section 3. Section 4 presents the impact of uncertain parameters in the integrated planning model while section 5 introduces results of sensitivity analysis. Section 6 discusses the findings and concludes the study.

2. INTEGRATED PLANNING MODEL

This study proposes an integrated planning scheme aiming to simultaneously expand the electricity and natural gas systems while considering the risk of uncertainties using a stochastic approach. The proposed long-term optimization model is a static planning problem performed for 2030, being 2015 the base year.

A flowchart to illustrate the proposed framework is presented in Fig.1.

Fig. 1. Flowchart for the long-term integrated planning model used in the study

Note that each big box represents a step to solve the problem. Initially, we have obtained the potential location and maximum availability of new power plants, such as wind and solar as well as gas, using the reports provided by the Australian Energy Market Operator, Powerlink and other utilities. The forecast of uncertainties considered in our problem is also obtained from these reports. The potential lines and pipelines are considered to access remote renewable and gas resources in Central and Far North Queensland as well as to attend increasing gas export demand. These potential candidates are input data to the model.

The proposed model includes generation expansion planning, transmission expansion planning as well as the expansion of gas supply and gas transmission. The optimization problem aims to minimize the cost of the system, where our key decision variables are the location, size, and type of new gas and electricity plants, as well as new transmission lines and pipelines, all from the potential candidate we have determined as input data. This input data inform the decisions of new investments and this is subject to a set of constraints such as electricity and gas demand balance, power and natural gas pipeline flow, maximum capacity that can be built for each proposed power plant and gas supply facility and so on.

The proposed stochastic planning model comprises of two-stage decisions as shown in the scenario tree of Fig 2. The scenario tree is composed of nodes and branches. While nodes are points in which decisions are made, branches represent different realizations of uncertain parameters [35]. Note that while the proposed model can be extended to consider a dynamic approach, this study follows the static approach used in the existing literature [6].

Fig.2. Scenario tree of the integrated planning model

The first stage decisions are related to investments in new power plants, gas supply facilities, new transmission lines and pipelines considering future gas and electricity demand and uncertainties. These decisions are independent of scenario realization of the stochastic process (here and now decisions) since they are made before the random process. The operating decisions are made in the second stage once the uncertainties are disclosed. These decisions are dependent on the outcome of investment decisions of the first stage and the realizations of the stochastic process (wait and see).

Finally, the problem is formulated as a (stochastic) mixed integer linear programming implemented using the General Algebraic Modelling System (GAMS) mathematical programming language, and solved using the IBM/CPLEX solver.

Among the expected results of our model is the type of technology, i.e. wind, solar PV, gas plants, investments in new gas supply facilities, their location and size, as well as decisions on whether invest on new transmission lines and pipelines. Operating decisions like power flow and power dispatch are also made.

2.1. Formulation of Integrated planning model

The proposed integrated planning problem is formulated in (1)-(16). The nomenclature of the proposed optimization model is given in Appendix A.

$$\text{Minimize Cost} \quad (\text{Electricity Cost} + \text{Natural Gas Cost}) \tag{1}$$

$$\boldsymbol{Electricity\ Cost} =$$

$$\sum_{w=1}^{W}\pi(w)\left\{\sum_{t=1}^{T}\tau(t)\left(\sum_{i=1}^{I}C_{i,t}^{V,Ex}.\,p_{i,t,w}^{Ex}+\sum_{i=1}^{I}C_{i,t}^{V,N}.\;p_{i,t,w}^{N}\right)+\sum_{t=1}^{T}\tau(t).\left(\sum_{i=1}^{I}C_{CO2}.\,(Em_i.\sum_{i=1}^{I}p_{i,t,w}^{Ex}+Em_i.\sum_{i=1}^{I}p_{i,t,w}^{N})\right)+\right.$$
$$\left.\left(\sum_{i=1}^{I}C_i^{F,N}{}_i.\,p_{i,w}^{C,N}+\sum_{i=1}^{I}C_i^{F,Ex}.\,p_i^{C,\,Ex}\right)+\left(\sum_{i=1}^{I}C_{i,w}^{Inv}.\;p_{i,w}^{C,N}+\sum_{k\in K^{new}}C_k^{Inv}.\;xfe_w^{K^N}\right)\right\} \tag{1α}$$

$+$

$$\boldsymbol{Natural\ Gas\ Cost} = \tag{1β}$$

Subject to:

$$\sum_{i\in n} p_{i,t,w}^{Ex} + \sum_{i\in n} p_{i,t,w}^{N} - \sum_{k|s(k)=n} f_{k,t,w} + \sum_{k|r(k)=n} f_{k,t,w} = \sum_{l\in n} P_{N^L,t,w}^{D}; \forall n,t,w \tag{2}$$

$$-F_k^{max} \le f_{k,t,w} \le F_k^{max}; \forall k \in K^{Ex}, t, w \tag{3}$$

$$-F_k^{max} \le f_{K^N,t,w} \le F_k^{max}; \forall k \in K^N, t, w \tag{4}$$

$$f_{k,t,w} = B_k.\left(\theta_{n,t,w} - \theta_{np,t,w}\right); \forall t, k \in K^{Ex}, w \tag{5}$$

$$f_{K^N,t,w} = B_k.xfe_w^{K^N}(\theta_{n,t,w} - \theta_{np,t,w}); \forall t, k \in K^N, w \tag{6}$$

$$p_{i,w}^{C,N} \le P_i^{C,max}; \forall i \tag{7}$$

$$0 \le p_{i,t,w}^{N} \le p_{i,w}^{C,N}.CF_{i,t} \;; \forall i, t, w \tag{8}$$

$$0 \le p_{i,t,w}^{Ex} \le p_i^{C,Ex}.CF_{i,t} \;; \forall i, t, w \tag{9}$$

$$\sum_{t=1}^{T} \tau(t). \sum_{i\in I^{RE}} (p_{i,t,w}^{N} + p_{i,t,w}^{Ex}) \ge E^{minRE}; \forall w \tag{10}$$

$$\begin{aligned}&\sum_{g\in ng} p_{g,b,t,w}^{G,N} + \sum_{g\in ng} p_{g,b,t,w}^{G,Ex} - \sum_{j|s(j)=ng} f_{j,b,t,w}^{G} + \sum_{j|r(j)=ng} f_{j,b,t,w}^{G} = \\ &\sum_{NG^D\in ng} G_{N^G,b}^{D} + \rho.\left(\sum_{i\in I^{UTEgas}} .p_{I^{UTEgas},t,w}^{T}.\tau(t)\right); \forall ng, w, b, t\end{aligned} \tag{11}$$

$$p_{g,b,w}^{C,N} \le P_g^{G,max}; \forall g \tag{12}$$

$$0 \le p_{g,t,b,w}^{G,N} \le \sum_{b=1}^{B} p_{g,b,w}^{C,N}.pf_{g,b}^{Gas}; \forall g,b,t,w \tag{13}$$

$$0 \le p_{g,b,t,w}^{G,Ex} \le p_{g,b}^{C,Ex}.pf_{g,b}^{Gas}; \forall g,b,w \tag{14}$$

$$-F_j^{G,max} \le f_{j,b,t,w}^{G} \le F_j^{G,max}; \forall j \in J \;, t, b, w \tag{15}$$

$$-F_j^{G,max}.xfg_w^{J^N} \le f_{j,b,t,w}^{G} \le F_j^{G,max}.xfg_w^{J^N}; \forall j \in J^N, t, w \tag{16}$$

The integrated planning approach, detailed in (1a) and (1b), is formulated as a stochastic cost function, assigning a probability distribution to a set of possible scenarios. The model aims to minimize the costs to expand generation units, transmission facilities, gas supply facilities and gas pipelines.

The minimization of the electricity system is defined in (1a). The first and second terms in round brackets represent the variable operating cost of existing and new generation units. The carbon cost of existing and new generating units is accounted for in the third and fourth terms in round brackets. The fixed operational cost, represented by the fifth and sixth terms, depends on the capacity of the new generators. The seventh term represents the investment cost of building new generation units, i.e. wind farms, utility-scale solar PV, Combined Cycle Gas Turbines (CCGT) and Open Cycle Gas Turbines (OCGT). Finally, the last term indicates the investment cost of building new transmission lines.

The expansion cost of the natural gas network defined in (1b) takes into consideration the operational cost of new and existing gas supply facilities as the first and second terms, respectively. The third term accounts for the investment cost in new gas supply facilities. Finally, the last term expresses the investment cost of building new gas pipelines to expand the current gas network.

The proposed cost function is subject to a number of constraints as follows. Constraints (2) to (10) apply to the electricity system and constraints (11) to (16) apply to the natural gas network.

Constraint (2) ensures electricity balance at each bus, in each time period and for each scenario. Constraints (3) and (4) enforce DC maximum and minimum power flow bounds of existing and prospective transmission lines, respectively. Constraints (5) and (6) represent the power flow of existing and prospective transmission lines, respectively. Prospective transmission line flow equation (6) is nonlinear due to the product of two variables. This equation is linearized due to the computational burden of nonlinear models and to achieve the global optimum solution to the problem that might be not be provided by the initial nonlinear model. Thus, the linear programming provides an appropriate tradeoff between modeling accuracy and solution efficiency. This is an international practice used widely in the literature for the nonlinear programming planning problems as in [17], [33],[36]. Thus, equations (4) and (6) are replaced by (4.1) and (6.1) respectively, applying a well-developed linearization technique used in [17].

$$-xfe_w^{K^N}.F_k^{max} \le f_{k,t,w} \le xfe_w^{K^N}.F_k^{max}; \forall k \in K^N, t, w \tag{4.1}$$

$$-\left(1 - xfe_w^{K^N}\right).M \le \frac{f_{k,t,w}}{B_k} - (\theta_{n,t,w} - \theta_{np,t,w}) \le \left(1 - xfe_w^{K^N}\right).M; \forall t, k \in K^N, w \tag{6.1}$$

Constraint (7) establishes the maximum power capacity that can be built by each type of generation technology according to the maximum availability of each resource at each bus, whereas constraint (8) and (9) sets bounds for electricity generation by new and existing generating units. Constraint (10) ensures a minimum generation to be supplied by renewable energy sources for a target year to fulfill the Mandatory Renewable Energy Target (RET) in Australia.

In constraint (11), the gas balance at each node and for each scenario is satisfied. This constraint ensures that the gas supply meets the non-power gas demand, i.e. business, residential, industrial and Liquefied natural gas (LNG) export, as well as the forecasted gas-fired consumption for 2030. Constraint (12) establishes a maximum capacity that can be built for each proposed gas supply facility. Constraints (13) and (14) establish a limit for new and existing gas production, respectively, to each gas supply facility in each scenario.

Natural gas pipeline flow is dependent on the nodal pressure difference, which is a nonlinear function solved by a method containing several iterations [33]. To simplify the integrated planning modelling and make the problem tractable, we follow the approach in [33], and model the natural gas pipeline flow using a minimum and maximum bound of pipeline capacity, represented by (15) and (16).

3. Case Study

The proposed integrated planning approach is applied to the realistic case of Queensland (QLD) within the Australian National Electricity Market (NEM), as shown in Fig. 3.

Fig. 3. Australian map

3.1. Demand data

The electricity demand for 2030 is obtained from AEMO in [37], which considers roof-top solar PV and the impact of demand side resources in its scenarios of load forecasting based on [38]. Historical data is considered in the AEMO's forecasting to represent demand patterns for Queensland. The estimated hourly electricity demand for 2029–2030 is represented by the net demand in this study, depicted in Fig. 4 [38]. Note that net demand is the original demand minus roof-top PV production.

Fig. 4. Forecasted hourly load distribution in Queensland (MW)

Gas demand forecasted by AEMO in [25] is divided into three classes, i.e. LNG export demand, residential, commercial and industrial demand and GPG (gas powered generation) demand. Historical data of several sources are used to develop a daily reference profile, which is used to produce a daily demand for the 20-year outlook period. Table 1 presents the 2030' Queensland gas demand. Note that LNG exports represent the bulk of gas demand at around 90%. Domestic customers are the second major type of gas demand, while the lowest share is given to gas-fired power plants. Gas demands for domestic and LNG exports are considered constant in this study as these demands can be supplied based on firm and long-term contracts. By contrast, gas demand for power plants varies according to gas-fired power production in the electricity system.

TABLE 1. GAS DEMAND FOR 2030 BY TYPE

In this study, we have not assessed the possibility of transforming gas demand into electricity demand by switching gas to electrical appliances, as we use load and gas forecast given by AEMO. This issue has been addressed in the literature for the integrated planning in [32]. A similar story is valid for electric vehicles integration impacts our model. Further, the use of electric vehicle in the transportation sector is not a major concern for Queensland in terms of gas consumption, since the vehicles fleet in Australia is supplied by petrol and it does not affect the natural gas consumption. This issue is beyond the scope of this study and is a subject of future research. However, it has already been addressed in the literature as in [39].

3.2. Supply Data

An equivalent electricity system of Queensland is built, which consists of 11 buses. In addition to the existing network, four new buses (buses 12-15) are considered to accommodate the enormous potential of wind and solar PV in remote locations. The proposed electricity system is depicted in Fig. 5.a. Note that besides the existing transmission lines, we consider 6 new transmission lines to transfer renewable energy from new buses to the existing network. Further, a ten-node gas system is built, given in Fig. 5.b. to represent the equivalent natural gas network in Queensland. The gas system comprises 8 major pipelines. Three new pipelines are also considered to facilitate gas export at gas node 6. As gas-fired power plants provide the linkage between gas and electricity networks, their locations in both systems are highlighted in Fig.5.

Fig. 5. Queensland equivalent electricity system (a) and natural gas system (b)

Determining the location of new investments in power plants, gas supply facilities, new transmission lines and pipelines in the Queensland equivalent electricity and natural gas systems are key decisions because it may influence the optimal operation, the infrastructure investments and reinforcements and the overall operational and expansion costs of the system. The potential location and size of new gas and electricity plants, as well as new transmission lines and pipelines, are input data to the model based on Australian Energy Market Operator and other utilities' reports.

The current Queensland's electricity system comprises 3 hydro power plants, 9 black coal, 12 gas-fired power plants i.e. 5 CCGTs, 6 OCGTs and 1 cogeneration plant. New additions to the existing power plant capacity need to be determined and placed in order to supply the 2030' load demand. To this end, 23 new generation candidates, consisting of 10 onshore wind farms, 5 utility-scale solar PVs (single axis tracking), 5 OCGTs and 3CCGTs are proposed. Note that no new hydro power plant is proposed for 2030. This meets the assumption of Australian Energy Market Operator (AEMO) that does not include any hydro in its future planning [24]. Although the state has historically been dependent on coal for the bulk of its generation, no new coal-fired capacity has been proposed due to the shift toward lower carbon technologies.

The natural gas network comprises 23 existing gas supply facilities located within the boundaries of the state of Queensland. The vast majority of natural gas supply is currently located in gas nodes 2, 5, 9 and 10 (see Fig.5.b). Additionally, we consider 3 more gas supply facilities currently under construction. These gas supply facilities are forecast to be completed in 2016 to supply the gas demand for exports. To supply 2030' natural gas demand, two new gas supply facilities are proposed, coming from coal seam gas (CSG) reserves of gas nodes 2 and 10. All the data of the electricity and natural gas networks used for the case study are presented in Appendix B (Tables B.1 to B.7).

3.3. Uncertainty characterization

In the process of planning, decision makers have to cope with the lack of perfect information, leading to short-term and long-term uncertainties. While short-term uncertainties includes renewable energy production, long-term uncertainties account for demand growth and gas price [30]. Thus, this study addresses the aforementioned short and long-term uncertainties using a stochastic programming approach. These uncertainties are categorized and detailed as follows.

The first set of uncertainty accounts for the net demand, wind and utility-scale solar PV production, presented in the following matrix.

$$\begin{bmatrix} \text{net demand scenario 1 for each bus} \\ \text{net demand scenario 2 for each bus} \\ \text{net demand scenario 3 for each bus} \\ \text{wind capacity factor scenario 1 (2008)for each unit} \\ \text{wind capacity factor scenario 2 (2009)for each unit} \\ \text{wind capacity factor scenario 3 (2010)for each unit} \\ \text{solar PV capacity factor scenario 1 (2008)for each unit} \\ \text{solar PV capacity factor scenario 2 (2009)for each unit} \\ \text{solar PV capacity factor scenario 3 (2010)for each unit} \end{bmatrix}$$

Three possible scenarios of net demand, wind and utility-scale solar PV production are simulated. We have used historical data from three years, i.e. 2008, 2009 and 2010, in which each year represents one scenario. To obtain three scenarios of net demand, the following approach is used. First, we use the hourly roof-top PV power traces (per MW) of these three years. Then, these roof-top PV scenarios are scaled up based on the roof-top PV capacity forecast of 2030, which is provided by AEMO [38]. Lastly, the hourly rooftop PV forecasts are subtracted from the 2030' original load forecast, in order to obtain three scenarios of the net demand. As for wind and utility-scale PV scenarios, their hourly capacity factors of the same three years (2008, 2009 and

2010) are used to represent their scenario realizations [38]. As the size of the above dataset makes the problem intractable, the k-means clustering technique is used to reduce the data to a smaller set of clusters as in [40]. In the k-means technique, each cluster is grouped according to similarities based on historical values of demand, wind and utility-scale solar PV of each node of the system (as discussed in the above matrix). The centroid of each cluster is represented by the mean value of these historical observations. Note that this technique allows keeping correlation among demand, wind and solar PV power in different nodes and time periods [41]. By using this technique, 8760 operating points (each hour of one year) are reduced to 24 clusters, each having a weight equal to its number of hours.

The second category of uncertainty consists of three scenarios of gas price. Table 2 presents gas price scenarios in 2030 for each technology and location in the Queensland equivalent electricity system. While gas price for scenarios reference and high is from [42], low price scenario is from [43].

TABLE 2. GAS PRICE SCENARIOS IN 2030 IN \$/GJ *(MWH)*

Overall, the proposed integrated planning model contains 9 scenarios, with the same probability of occurrence 1/9 (11%). The number of scenarios in a stochastic linear programming model vary but has to be limited especially when validated on a realistic case study that presents a great deal of computational burdening. This is in line with best practice in the literature, as for example references [44], [6], and [32] where two, four and six scenarios respectively are considered in the long-term planning of electricity and gas.

3.4. Simulation Results

The proposed integrated electricity and gas problem is formulated in mixed-integer linear programming, which is solved using the CPLEX solver under GAMS [45].

Three cases are considered here.

- Case 1 simulates planning of Queensland electricity and gas systems while disregarding environmental requirements.
- In case 2, the integrated planning of electricity and gas networks considers the retirement of 3,080 MW of existing coal capacity, about 38% of total generation. As a large share of coal-fired capacity in Queensland will be approaching end-of-life in 2030, it seems likely to consider the impacts of their retirement in the future planning.
- Case 3 simulates the impact of a stronger environmental policy on the integrated planning problem. In this case, the inclusion of a carbon price of \$24 per ton is considered. This carbon price was chosen given its charging to Australia's biggest carbon

emitters from 2011 to 2014. In addition to the carbon cost, a minimum target of 20% renewable energy production and the retirement of part of the existing coal-fired capacity are also considered.

The Australian Energy Market Operator's considers two different scenarios of economic growth and technology development in its planning, which impact the future renewable technologies' investment cost. To assess the impact of capital cost in the investment decisions, this study uses these two scenarios provided by AEMO, i.e. slow technology development (high investment cost) and quick technology development (low investment cost) by 2030 (see Table 3). The annualized capital cost is calculated applying a capital recovery factor $[i\left(1+i\right)^{n} \,/\, ((1+i)^{n}-1)]$ to the total investment cost of each technology presented in Table 3. An interest rate (i) of 9% and lifetime(n) of generation plants equal to 20 years is considered based on [17]. Note that the interest rate affects the annualized capital cost of power plants, which impacts their competitiveness. This is particularly important for capital-intensive power plants, such as renewable energy. A high interest rate affects the competitiveness of these plants and could exclude or even postpone their construction. As more interest has to be paid, the annualized capital cost increases, which turns them a more expensive option. On the other hand, a low interest rate turns these technologies more competitive, as these plants become more affordable compared to conventional plants. Thus, depending on the interest rate chosen for a project, different investments on new power plants can be obtained.

TABLE 3. INVESTMENT COSTS OF TECHNOLOGIES IN 2030 ($/MW)

Hereafter, we present and compare the results for the above three cases for high and low investment costs.

Table 4 depicts the total planning cost to meet 2030' electricity load and gas demand. The results are presented for an integrated and individual planning (stand-alone) of both sectors. While integrated planning addresses the expansion of electricity and gas networks simultaneously, stand-alone planning is carried out separately, obtaining first the optimal results of the gas-fired generation of the electricity network to be used then as an input to the gas network.

TABLE 4. DISCOUNTED TOTAL COST TO EXPAND ELECTRICITY AND GAS SYSTEMS (BILLION $)

The results indicate that stand-alone planning costs are respectively about 13%, 8% and 7% higher for cases 1, 2 and 3 than the integrated planning approach when the high investment cost is applied. For the low investment cost, the cost difference is higher, being 14%, 9% and 8% for cases 1, 2 and 3. The cost difference between standalone and integrated planning are explained by the construction of a new gas supply facility in the stand-alone planning, while in the integrated planning no new gas supply facility is needed. Indeed, when the planning is carried out separately, the use of existing gas facilities is not optimized in the electricity network, as the gas network constraints are unknown.

As the bulk of future electricity generation remains based on existing coal in case 1, this case has the lowest expected cost to expand both networks. However, retiring existing coal-fired generation leads to a significant cost increase in case 2, given the higher investment in the new generation capacity. With the introduction of environmental requirements, case 3 presents the highest overall cost, with 74% and 65% higher than case 1 for high and low investment costs, respectively, due to the higher investments in renewable capacity.

The optimal electricity generation mix from existing and new generators for 2030 of each case is presented in Table 5 for the integrated and individual planning approaches. Note that the electricity generation is the same for both low and high investment costs in all three simulated cases.

TABLE 5. EXPECTED 2030' ELECTRICITY GENERATION IN EACH CASE IN *GWH*

The coal retirement will significantly affect gas-fired generation, about 29% and 45% higher than case 1 for integrated and stand-alone planning solutions respectively. In addition, existing hydro and wind generation helps to alleviate the reliance on coal generation, with significant increases in case 2. When the renewable target is introduced in case 3, wind generation increases 23%. By contrast, the amount of fossil fuel generation is 10% lower than case 2. As the link between electricity and gas systems occurs through gas-fired generation, when the expansion planning is performed in an integrated way, the amount of gas-fired generation is optimized. Thus, the amount of gas-fired generation in integrated planning is lower than in stand-alone planning, with 18% less in case 3.

The results presented above clearly demonstrate the benefits of performing integrated planning which leads to a lower cost of both systems and a more efficient use of gas. Accordingly, we will hereafter present the key results of the integrated planning approach only.

The optimal investment capacity of each technology in the given cases is depicted in Fig 6. Note that the power capacity for high and low investment costs is the same in all three cases.

Fig. 6. Expected power capacity built

Case 1 only invests on gas fired generation (5,527 MW of CCGTs and OCGTs), as gas is the most economical source compared to other technologies. All 3,450 MW OCGT capacity proposed is built while 2,077 MW of CCGT is built. It is worth mentioning that 1,000 MW of CCGT (about 50% of total built) is invested at bus 7, which has the highest load demand in the network (see locations in Fig.5.a). In case 2, all the proposed gas power plants are built while a significant investment in wind capacity, around 2,307 MW is also needed to offset the coal retirement. Note that no utility-scale solar PV is built in this case. Case 3 involves two conflicting objectives, i.e. cost and environmental requirements. Accordingly, the most competitive technologies are not preferred but those that balance the cost with the environment goal are chosen. This case presents the highest investment on the renewable capacity at 2,605 MW. This high renewable capacity causes less investment on CCGT, which is 3% lower than that of case 2.

The 2030' natural gas demand will remain being supplied by gas nodes 2, 9 and 10 as shown in Table 6. The integrated planning optimal solution does not include any gas supply from gas node 5, given its higher operation cost. This way, the gas demand of nodes 3 and 4 will be supplied by gas facilities of node 10 and transferred to node 5 by an existing gas pipeline (see Fig 4.b). As the amount of gas supply follows the gas-fired generation, case 2 presents the highest gas supply while case 1 presents the lowest. While the gas supply amount is the same for both high and low investment costs in cases 1 and 2, case 3 presents a small difference in the gas supply of gas node 9 and 10.

TABLE 6. GAS SUPPLY LOCATION FOR 2030 IN EACH CASE IN TJ *(MWH)*

Natural gas pipelines' utilization rate of each case is presented in Table 7. It can be seen that the utilization rate of three of nine major existing pipelines, which connects gas nodes 9 and 6, will be around 90% of their capacity in 2030, which might incur additional costs to supply the future gas demand.

TABLE 7. EXPECTED PIPELINE CAPACITY UTILIZATION RATE IN %

No investments in the gas pipelines are needed to supply 2030' gas demand in any of the simulated cases. It is worth mentioning that we consider assets connected to the export node (three gas supply facilities and three pipelines) which are currently under construction. Thus, it seems that building these assets is critical to supply the future LNG export demand.

As expected, the inclusion of environmental constraints reduces the amount of carbon dioxide emitted, shown in Fig. 7. By having the least amount of fossil fuel generation, case 3 presents the lowest expected emission of carbon dioxide, with 39 Mton. By contrast, case 1 has the highest carbon dioxide emission, approximately 13.2 Mton higher than case 3 for both high and low investment costs.

Fig. 7. Expected Carbon emission of each case in Mton of CO2

3.4.1. Impact of high renewable energy penetration

The Queensland Government is considering the possibility of establishing a 50% renewable energy target by 2030. Accordingly, this section further assesses the high penetration of renewable energy, up to 50%, on long-term integrated planning in this state.

Table 8 delivers the conflicting objectives of CO_2 emission and total cost. It is clear that higher penetrations of renewable energy result in lower carbon emissions and a more expensive system. The interesting outcome is that as the percentage of renewable energy increases, the rate of changes in both criteria accelerates. For instance, when the 30% target is applied, carbon dioxide is 9% lower while the cost is 17% higher compared to the 20% target. However, the 50% target reduces CO_2 emissions by 16%, whereas the cost is 26% higher than the 40% target for high investment cost. This may be a result of the reduction of coal share on electricity mix when the renewable target increases while increasing investments will be needed for its replacement.

TABLE 8. EXPECTED CARBON EMISSION AND COST OF EACH TARGET

Fig. 8 illustrates the power capacity of new technologies for various penetration levels of renewable energy target for 2030. While all scenarios build wind capacity, more investments in solar PV will follow the increase in the target. The highest impact on fossil fuel technologies will be on CCGT, with a decrease of 79% in the case of 50% renewable energy compared to 20% RET for both investment costs.

As shown in Fig 8, the investment on new renewable capacity is the same for both investment costs when 20% RET is introduced. However, higher renewable targets (30% and 40% RET) lead to differences in the amount of power capacity invested. When the high investment cost is simulated, more investments in wind capacity are seen while solar PV investments are clearly lower compared to the power capacity invested in the low investment cost. This is explained by the higher cost difference of renewable technologies in the high investment cost scenario, which makes a more economically affordable investment in wind power capacity.

In both investment cost scenarios, wind capacity increases by 128% from the 20% to the 50% target. Solar PV capacity is built only with the 40% RET in the high investment cost while in the low investment cost it grows 82% from the 30% to the 50% RET. Note that the total capacity built increases 46% when the target increases from 20% to 50% due to the addition of wind and PV, which have low capacity factors and impose intermittency to the system.

Fig. 8. Expected power capacity of different Renewable Target

Investments in the new power capacity in the 40% renewable target are presented in Fig. 8 for both high and low investment costs. From all renewable capacity built, 53% of wind and 100% of solar PV will come from new buses when the high investment cost is simulated while for the low investment cost, 55% of wind and 100% of solar PV capacity are built in new buses (i.e. Buses 12-15). By comparing both scenarios of investment costs, it can be noticed that more investments in wind capacity is observed (see bus 13) in the high investment cost, about 186 MW. On the other hand, higher investment in solar PV capacity is noted (see bus 15) when the low investment cost is simulated.

The electricity production of various resources is depicted in Table 9. The significant increase in the electricity generation of wind is evident when the target increases, while a considerably higher solar PV production is also apparent with the introduction of the 40% and 50% target. The interesting point is that while a substantial reduction in gas generation is witnessed from the 20% target to the 50% target, coal-fired power generation decreases only 21% in both high and low investment costs. Note that coal power reduction is due to its highest emission factor, although it has the cheapest fuel cost.

Fig. 9. Location and Capacity built in 40% RET in MW

TABLE 9. EXPECTED ELECTRICITY GENERATION FOR 2030 IN GWH

The increasing renewable target will help to alleviate the gas flow in pipelines due to the lower gas consumption of gas-fired power plants as shown in Table 10. However, as increased investments in renewable sources will be necessary, new transmission lines will be built to transfer renewable power of new buses, as seen in Table 11. Note that up to 30% Renewable energy target, only two new transmission lines are built. However, when higher renewable energy targets are introduced (40 and 50% RET), more transmission lines needs to be built, increasing the cost to expand the transmission system.

TABLE 10. EXPECTED PIPELINE CAPACITY UTILIZATION RATE IN %

TABLE 11. TRANSMISSION LINES BUILT IN EACH TARGET PENETRATION

4. IMPACT OF UNCERTAIN PARAMETERS

This section assesses the effects of each uncertain parameter, i.e. of renewable power, load growth, and gas price in the long-term integrated planning. To this end, the Queensland case study is illustrated considering 50% RET and high investment cost.

Fig.10 presents the results of power capacity built for 2030 considering future gas price and load demand growth as known (certain) parameters. Note that the result displayed in the first column considers that we know the 2030 gas price while the second column displays the result of a known load demand for 2030. The results show that a lower power capacity is built for 2030 if the future gas price is known (see Fig.8 for comparison). The differences in new power capacity built for 2030 is visible for solar PV and CCGT capacity. While solar PV capacity is 331 MW lower, CCGT capacity built is 267 MW lower. Similar results are obtained if load demand for 2030 is known. By decreasing the power capacity built for 2030, the total cost to expand the integrated system is around 11.30 billion dollars, approximately 700 million dollars lower, for both load and gas price certain inputs.

Fig 10. Expected Power capacity built for 2030 (MW)

Table 12 presents the results when renewable energy output is considered as certain in the integrated planning model. By comparing the results of uncertain renewable energy production (see Fig.8 for comparison), it can be noted that if the output of renewable generation is known, less power capacity is built in 2030 for solar PV and CCGT, around 11% and 58% respectively.

Note that when there is certainty about the gas price, load growth, and renewable energy output, the results show that a smaller power capacity is built for 2030. However, this may affect the energy security, especially if the future energy demand proves to be higher than the certain forecast. Thus, the additional power capacity built in the stochastic approach is to guarantee the energy security. This indicates that the proposed stochastic method provides more consistent results for all demand scenarios.

TABLE 12. EXPECTED POWER CAPACITY BUILT FOR 2030 IN MW

5. SENSITIVITY ANALYSIS

To demonstrate the applicability and consistency of our mathematical formulation, this session performs a sensitivity analysis using the Queensland case study. We have simulated the impact of load variation using two cases, i.e. a 10% increase in the load demand and 10% decrease in the load demand. These load variations are applied to 50% RET case with high investment cost and compared with the original 50% RET case. The results of load variation (sensitivity analysis) are presented in Tables 13 and 14.

The expected power capacity built for 2030 is presented in Table 13. A 10% load increase requires an increase of 13% in power capacity while a 10% load decrease reduces in 14% the power capacity built. The difference in the power capacity built in these cases is exclusively from gas-fired plants (CCGT and OCGT). When the load demand increases, more capacity of CCGT, around 1650 MW higher, is built to cope with this increase. These plants are built in buses 5 and 7 to supply the load increase of bus 7, which has the highest share of load demand. The 10% decrease in load, reduces the investments in OCGT and CCGT capacity around 1284 MW and 2274 MW, respectively.

Table 14 shows the difference between the total costs to expand both networks for the three cases. Note that an increase of 10% of load demand has a cost increase of 6% while a decrease of 10% in load demand reduces the cost by 5%, which indeed prove the sensitivity of the proposed mathematical to load variations.

TABLE 13. EXPECTED 2030' POWER CAPACITY BUILT IN MW

TABLE 14. DISCOUNTED TOTAL COST TO EXPAND ELECTRICITY AND GAS SYSTEMS (BILLION $)

6. CONCLUSION

This study proposes a long-term integrated planning of electricity and gas intended to satisfy the 2030's electricity and gas demand at the lowest cost while considering new policies towards future clean energy. A stochastic cost function is mathematically formulated to address the uncertainties faced by both systems. The proposed problem is solved for the state of Queensland, Australia with the following outcomes.

The findings of this study suggest that performing an integrated planning of electricity and gas leads to a lower overall cost of both systems and a more efficient allocation and utilization of gas compared to a stand-alone analysis. For the case study of Queensland, around $500 million can be saved when the long-term planning of electricity and gas is performed together. This finding is corroborated by previous studies on integrated planning such as [31], that shows a saving of $2.7 billion for the Brazilian power system. This saving is higher when compared to our study given the size of the electricity system evaluated in [31]. This result is consistent and indicates that our mathematical modeling is correct.

The results of integrated planning for Queensland case study suggest an increase in the total cost when new environmental constraints are introduced given the need for higher investments in renewable energy and natural gas power capacity. Natural gas will play an important role in replacing future coal retirements while its share will be reduced with the increasing renewable energy targets. To accommodate higher renewable energy targets, significant investments in the transmission system as well as in new power capacity of wind and solar PV is needed, with most of them coming from new buses. Although no investments in the gas network are needed to supply future gas demand, increasing penetration of renewable sources will help to alleviate the gas flow in pipelines, which will be close to full capacity in 2030. In addition, depending on the technology cost development in 2030, the Queensland state will expect distinctive investments on new power plants, which is more obvious in higher penetration of renewable energy.

The finding of this study provides information on the impacts of high renewable sources penetration on the investments of electricity and natural gas networks in long term. This helps decision-makers in choosing an optimal investment strategy to support a transition towards clean energy as well as to anticipate the possible infrastructure bottlenecks that may exist in the future. It should be noted that an appropriate expansion plan of both networks not only prevents unnecessary costs but also avoids the electricity disruption and gas shortage.

APPENDIX A. NOMENCLATURE

A) Indices and Sets

n	Index for system bus
i	Index for power generation units
k	Index for transmission lines
$r(k)$	Receiving-end node of transmission line k
$s(k)$	Sending-end node of transmission line k
l	Index for load demand
t	Index for time period
w	Index for scenarios
I^{RE}	Set of renewable energy units
I^{UTEgas}	Set of gas-fired power plants
K^{N}	Set of new transmission lines
K^{Ex}	Set of existing transmission lines
N^{L}	Set of power demands connected to bus
b	Index for blocks
g	Index for natural gas supply projects
j	Index for natural gas pipelines
$r(j)$	Receiving-end node of natural gas pipeline j
$s(j)$	Sending-end node of natural gas pipeline j
ng	Index for gas nodes
G^{N}	Set of new natural gas supply projects
J^{N}	Set of new natural gas pipelines
J^{Ex}	Set of existing natural gas pipelines
NG^{D}	Set of gas demand connected to gas nodes

B) Variables

$xfe_{w}^{K^N}$	Binary variable indicating if new transmission line is built or not in scenario w
$p_{i,t,w}^{Ex}$	Electricity production of existing unit i during time period t in scenario w [MW]
$p_{i,t,w}^{N}$	Electricity production of new unit i during time period t and scenario w[MW]

$p_{I^{UTEgas},t,w}^{T}$	Electricity production of existing and new gas-fired unit i during time period t and scenario w[MW]
$p_{i,w}^{C,N}$	Power capacity to be built for new unit i and scenario w [MW]
$p_{i}^{C,Ex}$	Power capacity of existing unit i [MW]
$\theta_{n,t,w}$	Voltage angle at bus n in time period t in scenario w
$f_{k,t,w}$	Power flow through transmission line k in time period t, and scenario w [MW]
$xfg_{w}^{J^N}$	Binary variable indicating if new gas pipeline is built or not in scenario w
$f_{j,b,t,w}^{G}$	Gas flow j in block b, time period t, and scenario w [TJ]
$p_{g,b,w}^{C,N}$	Gas supply capacity of new gas projects g in block b and scenario w [TJ/year]
$p_{g,b}^{C,Ex}$	Gas supply capacity of existing gas projects g and in block b [TJ/year]
$p_{g,b,t,w}^{G,N}$	Gas production of new gas supply projects g in block b, time period t, and scenario w [TJ/ h]
$p_{g,b,t,w}^{G,EX}$	Gas production of existing gas supply projects g in block b, time period t, and scenario w [TJ/h]

C) Parameters

$P_{N^L,t,w}^{D}$	Demand at bus n, during time period t and scenario w [MW]
$CF_{i,t}$	Capacity factor of electricity unit i during time period t [p.u]
$C_{i,w}^{Inv}$	Annualized capital cost of new generation units i and in scenario w [$/MW]
C_{k}^{Inv}	Annualized capital cost of new transmission line k [$]
$C_{i,t}^{V,Ex}$	Variable operating cost of existing electricity unit i and during time period t [$/MWh]
$C_{i,t}^{V,N}$	Variable operating cost of new electricity unit i and during time period t [$/MWh]
$C_{i}^{F,Ex}$	Fixed operating and maintenance cost of existing electricity unit i [$/MW/year]
$C_{i}^{F,N}$	Fixed operating and maintenance cost of new electricity unit i [$/MW/year]
C_{CO2}	Carbon Cost [$/ton CO_2]
$P_{i}^{C,max}$	Maximum capacity investment potential of unit i [MW]
E^{minRE}	Minimum renewable energy target [MW]
Em_i	Emission of unit i [tons CO_2-e/MWh]
F_{k}^{max}	Maximum capacity of transmission line k [MW]
$\tau(t)$	Duration of each time period t [hour]
B_k	Susceptance of transmission line k [p.u]
$\pi(w)$	Probability of scenario w [%]
$pf_{g,b}^{Gas}$	Participation factor of gas supply facilities g and in block b [p.u]

ρ	Conversion rate of electricity to gas [p.u.]
$G^{D}_{N^G,b}$	Gas demand at gas node *ng* and in block *b* [TJ]
$P^{G,max}_{g}$	Maximum limit of gas supply of projects *g* [TJ]
$F^{G,\,max}_{j}$	Maximum gas flow of gas pipeline *j* [TJ]
$C^{op}_{g,b}$	Operational cost of gas production facilities *g* and in block *b* [$/TJ]
C^{Inv}_{g}	Annualized capital cost of new gas production facilities *g* [$]
C^{Inv}_{j}	Annualized capital cost of new gas pipelines *j* [$]
$\delta(b)$	Duration of each block *b* [day]

APPENDIX B. CASE STUDY DATA

Table B.1. presents the existing capacities of power plants as well as the retirement announced by the market operator by 2030 [24]. Prospective installed capacity of new generators and their location in Queensland's electricity system are presented in Table B.2. Economic [46] and environmental input data [47] of these generators are presented in Table B.3. Data of the proposed transmission lines are depicted in Table B.4.

TABLE B.1. EXISTING GENERATION CAPACITY AND RETIREMENT

TABLE B.2. LOCATION AND CAPACITY OF NEW GENERATORS

TABLE B.3. NEW GENERATORS PARAMETERS

TABLE B.4. NEW TRANSMISSION LINES DATA

Existing domestic gas supply facilities as well as their locations in the Queensland natural gas system are presented in Table B.5 based on [25] while the proposed gas supply facilities are provided in Table B.6 [48]. Table B.7 presents the capacity as well as costs of the proposed gas pipelines [48].

TABLE B.5. DATA OF EXISTING GAS SUPPLY FACILITIES

TABLE B.6. PROPOSED GAS PRODUCTION FACILITIES PARAMETERS

TABLE B.7. PARAMETETERS OF PROPOSED GAS PIPELINES

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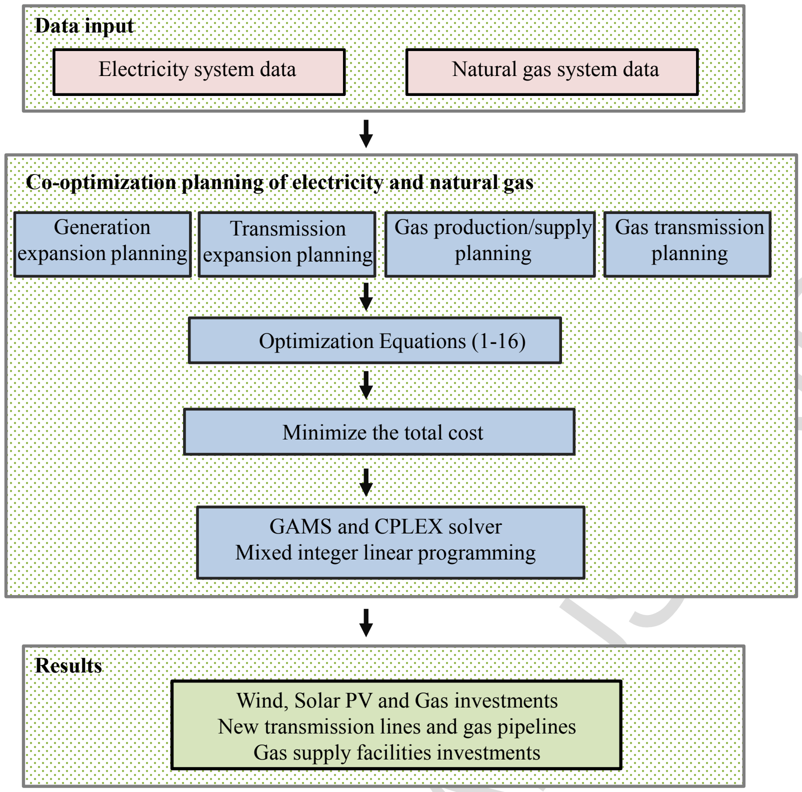


Fig. 1. Flowchart for the long-term integrated planning model used in the study

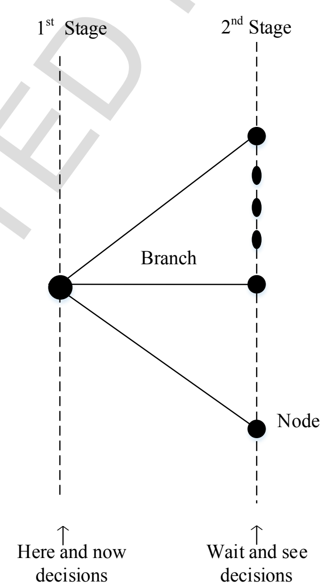


Fig.2. Scenario tree of the integrated planning model

Fig. 3. Australian map

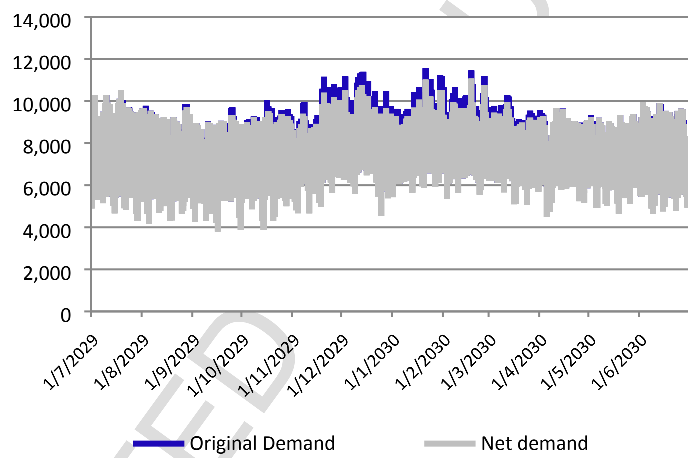


Fig. 4. Forecasted hourly load distribution in Queensland (MW)

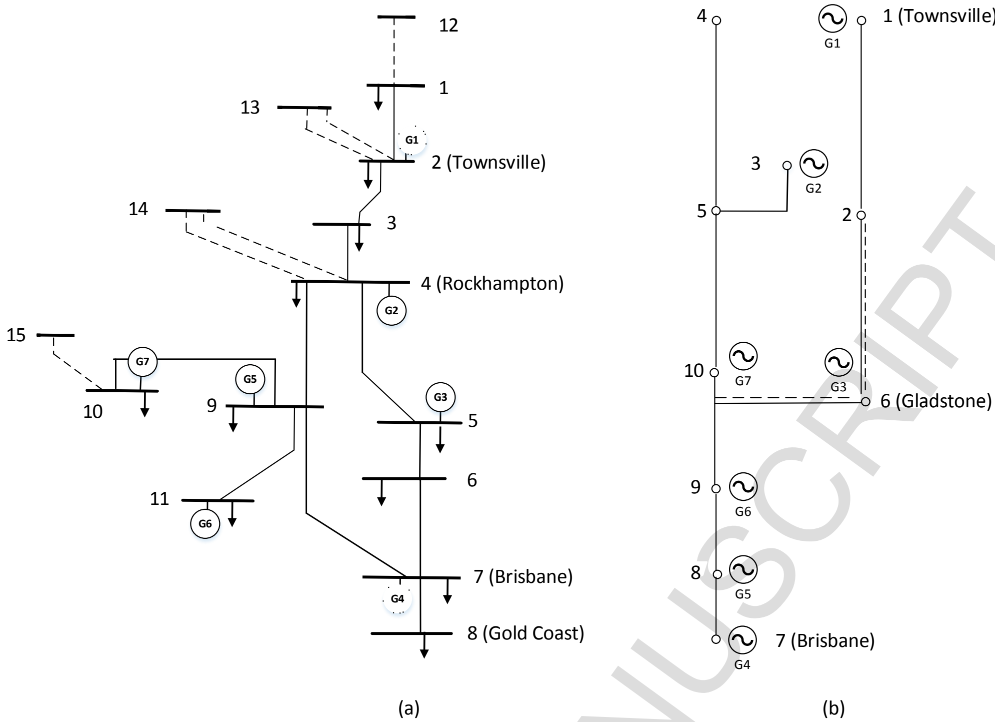


Fig. 5. Queensland equivalent electricity system (a) and natural gas system (b)

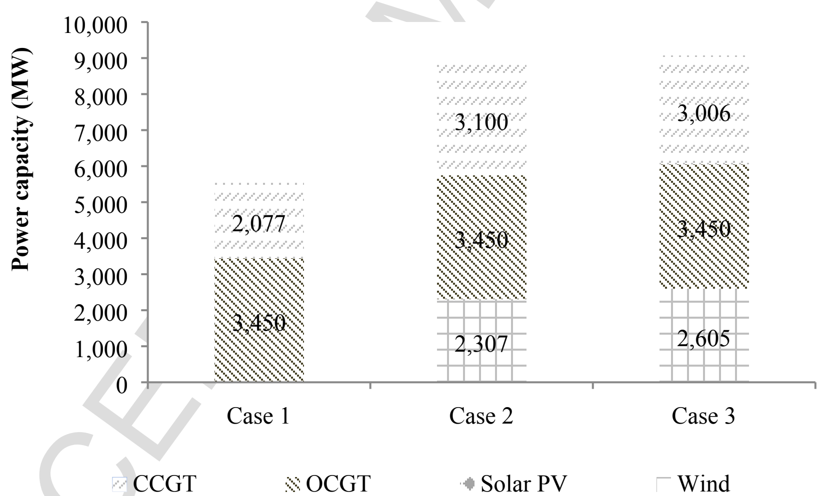


Fig. 6. Expected power capacity built

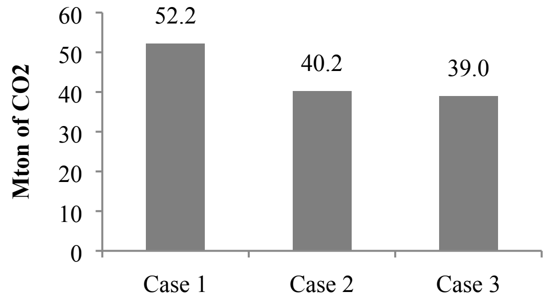


Fig. 7. Expected Carbon emission of each case in Mton of CO2

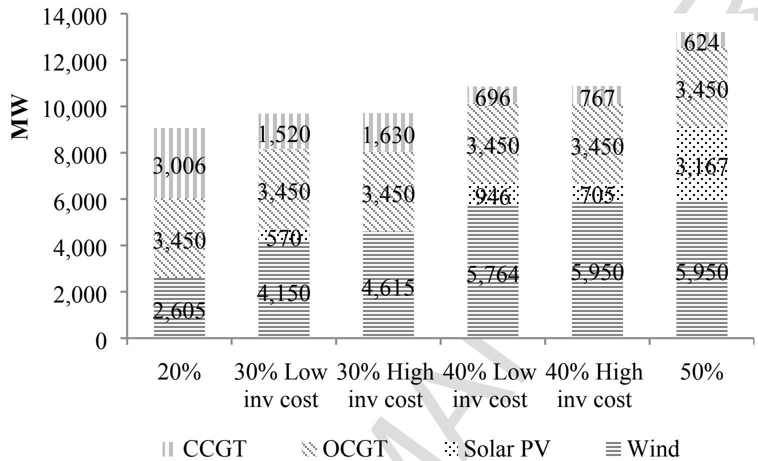
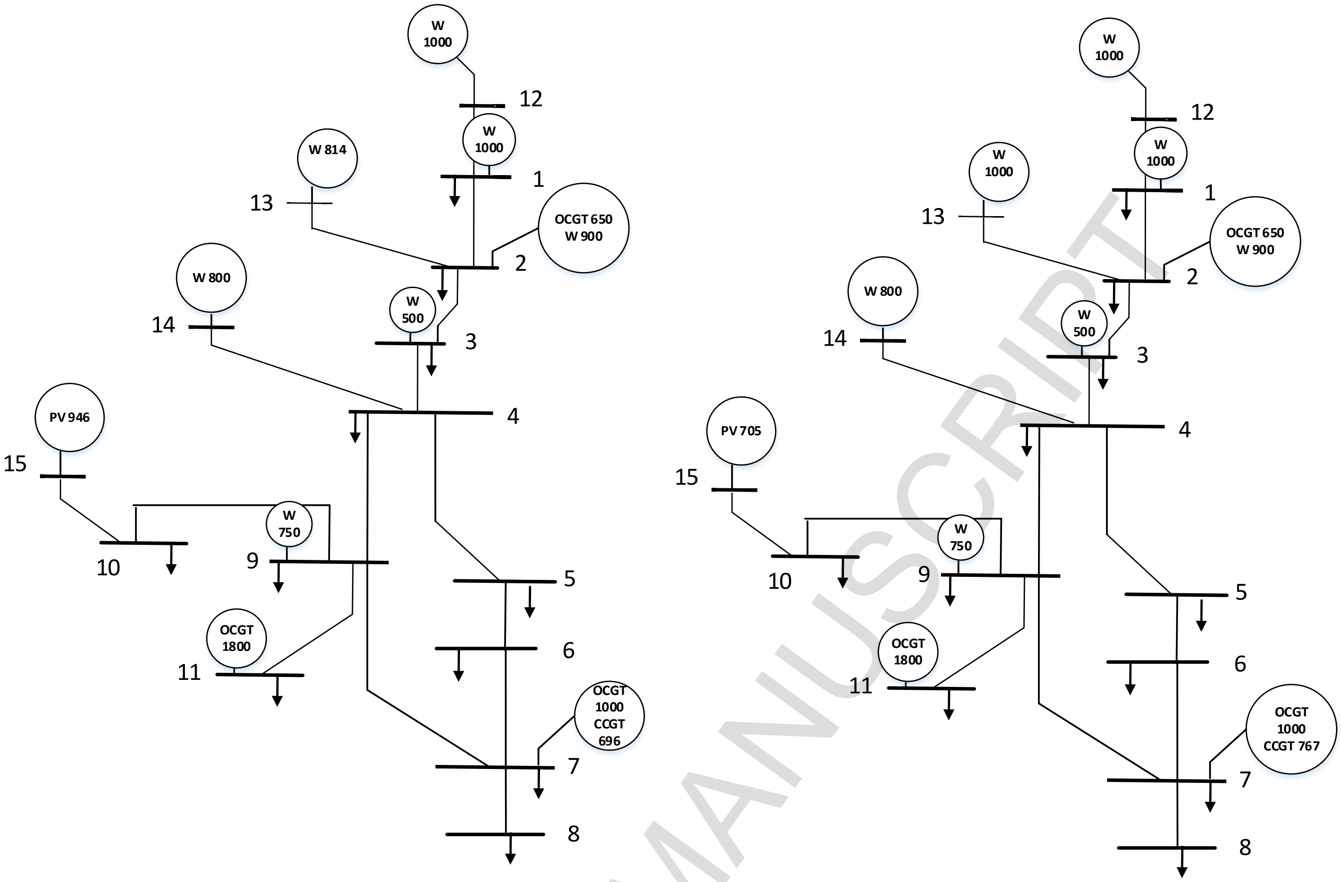


Fig. 8. Expected power capacity of different Renewable Target



Low investment cost High investment cost

Fig. 9. Location and Capacity built in 40% RET in MW

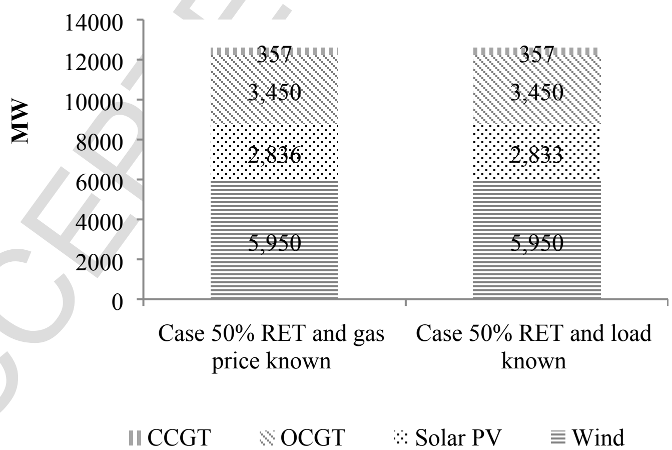


Fig 10. Expected Power capacity built for 2030 (MW)

TABLE 1. GAS DEMAND FOR 2030 BY TYPE

Demand Type	***TJ*** *(MWh)*
Residential+ commercial	**9,808** *(2,724,444)*
Industrial	**134,855** *(37,459,722)*
LNG Exports	**1,421,913** *(394,975,833)*
Gas Power Generation	**Variable** (~50,000)

TABLE 2. GAS PRICE SCENARIOS IN 2030 IN $/GJ *(MWH)*

Technology	**Bus**	**Scenario low**	**Scenario reference**	**Scenario high**
OCGT	1-3	8.45 (*2.35*)	16.12 (*4.47*)	17.70 (*4.91*)
OCGT	4-5	8.55 (*2.37*)	16.49 (*4.58*)	18.14 (*5.03*)
OCGT	6-8	8.30 (*2.30*)	15.75 (*4.37*)	17.30 (*4.80*)
OCGT	9-11	8.45 (*2.35*)	15.85 (*4.40*)	17.40 (*4.83*)
CCGT	1-3	6.90 *(1.92)*	12.90 (*3.58*)	14.19 (*3.94*)
CCGT	4-5	7.00 (*1.94*)	13.19 (*3.66*)	14.51 (*4.03*)
CCGT	6-8	6.80 (*1.89*)	12.60 (*3.50*)	13.86 (*3.85*)
CCGT	9-11	6.85 (*1.90*)	12.68 (*3.52*)	13.95 (*3.87*)

TABLE 3. INVESTMENT COSTS OF TECHNOLOGIES IN 2030 ($/MW)

Technology	**Quick technology development (low investment cost)**	**Slow technology development (high investment cost)**
Wind	2,342,712	2,960,912
Solar PV	2,270,508	3,523,059
OCGT	792,487	648,399
CCGT	1,330,303	1,433,973

TABLE 4. DISCOUNTED TOTAL COST TO EXPAND ELECTRICITY AND GAS SYSTEMS (BILLION $)

Cases	**Investment Cost**	**Electricity planning stand alone**	**Gas planning stand alone**	**Total cost of stand-alone planning**	**Integrated Electricity and Gas planning**
Case 1	High	1.848	2.607	4.455	3.948
	Low	1.645	2.607	4.251	3.745
Case 2	High	4.232	2.632	6.864	6.352
	Low	3.591	2.632	6.223	5.710
Case 3	High	4.763	2.630	7.392	6.878
	Low	4.072	2.630	6.701	6.186

TABLE 5. EXPECTED 2030' ELECTRICITY GENERATION IN EACH CASE IN *GWH*

Cases	Inv Cost	Planning scheme	Hydro	Wind	Gas	Coal	Solar
C1	High and Low	Integrated	772	0	15,400	45,810	0
	High and Low	Stand alone	504	0	15,668	45,810	0
C2	High and Low	Integrated	2,480	8,052	19,817	31,633	0
	High and Low	Stand alone	2,480	5,168	22,701	31,633	0
C3	High and Low	Integrated	2,480	9,916	17,899	31,688	0
	High and Low	Stand alone	2,480	9,916	21,931	27,655	0

TABLE 6. GAS SUPPLY LOCATION FOR 2030 IN EACH CASE IN TJ *(MWH)*

Gas node	Case 1	Case 2	Case 3 (Low inv.cost)	Case 3 (High inv.cost)
NG2	22,685 (*6,301,389*)	22,795 (*6,331,945*)	22,576 (*6,271,111*)	22,576 (*6,271,111*)
NG9	543,484 (*150,967,778*)	553,980 (*153,883,334*)	539,912 (*149,975,556)*	539,983 (*149,995,278*)
NG10	1,055,221 (*293,116,944*)	1,060,515 (*294,587,500*)	1,067,896 (*296,637,777*)	1,067,826 (*296,618,333*)

TABLE 7. EXPECTED PIPELINE CAPACITY UTILIZATION RATE IN %

Supply node	Demand node	Case 1		Case 2		Case 3	
		Low inv. Cost	High inv. cost	Low inv. Cost	High inv. cost	Low inv. cost	High inv. cost
NG2	NG1	42.4	42.4	39.7	39.7	39.2	39.1
NG5	NG3	7.6	7.6	8.2	8.2	6.3	6.2
NG5	NG4	55.3	55.3	55.3	55.3	55.3	55.3
NG9	NG6	91.1	90.8	93.0	93.0	90.5	90.1
NG10	NG5	23.8	23.8	24.4	24.4	22.6	22.6
NG10	NG6	88.5	88.7	88.9	88.9	89.8	90.0
NG9	NG7	42.1	42.1	42.6	42.6	43.5	43.5

TABLE 9. EXPECTED ELECTRICITY GENERATION FOR 2030 IN GWH

Renewable Target (%)	Inv.Cost	Hydro	Wind	Gas	Coal	Solar
20	High and Low	2,480	9,916	17,899	31,688	0
30	High	2,480	16,114	11,440	31,947	0
	Low	2,480	14,869	11,545	31,843	1,245
40	High	2,480	20,527	7,511	29,678	1,786
	Low	2,480	19,914	7,491	29,698	2,398
50	High	2,480	20,581	5,904	25,094	7,937
	Low	2,480	20,574	5,904	25,087	7,937

TABLE 10. EXPECTED PIPELINE CAPACITY UTILIZATION RATE IN %

Supply node	Demand node	30% RET		40% RET		50% RET	
		Low inv. cost	High inv. cost	Low inv. Cost	High inv. cost	Low inv. Cost	High inv. cost
NG2	NG1	40.0	39.5	39.4	39.1	37.7	37.7
NG5	NG3	1.7	3.2	0.3	0.3	0.2	0.2
NG5	NG4	55.3	55.3	55.3	55.3	55.3	55.3
NG9	NG6	96.2	89.4	89.7	89.3	93.6	93.3
NG10	NG5	18.6	19.9	17.3	17.3	17.3	17.3
NG10	NG6	86.2	89.2	88.9	89.1	87.2	87.3
NG9	NG7	38.2	37.7	30.7	31.2	26.3	26.3

TABLE 11. TRANSMISSION LINES BUILT IN EACH TARGET PENETRATION

RET (%)	Investment Cost	Number	Lines built type	From Bus	To Bus	Cost of transmission system *M $*
20	High and Low	1	275 kV	12	1	165
30	High	1	275 kV	12	1	305
		1	275 kV	14	4	
30	Low	1	275 kV	12	1	235
		1	275 kV	15	10	
40	High and Low	1	275 kV	12	1	445
		1	275 kV	13	2	
		1	275 kV	14	4	
		1	275 kV	15	10	
50	High and Low	1	275 kV	12	1	635
		2	275 kV	13	2	
		1	275 kV	14	4	
		1	275 kV	15	10	

TABLE 12. EXPECTED POWER CAPACITY BUILT FOR 2030 IN MW

Technology	Case 50% RET and Renewable energy known
Hydro	0
Wind	5950
Solar PV	2813
OCGT	3450
CCGT	262
Coal	0
Discounted Total Cost	11.24

TABLE 13. EXPECTED 2030' POWER CAPACITY BUILT IN MW

Cases	Hydro	Wind	OCGT	CCGT	Solar	Total
C6	0	5950	3450	624	3167	**13,191**
Case 6_10% higher load	0	5950	3450	2274	3167	**14,841**
Case 6_10% lower load	0	5950	2166	0	3196	**11,312**

TABLE 14. DISCOUNTED TOTAL COST TO EXPAND ELECTRICITY AND GAS SYSTEMS (BILLION $)

Cases	Investment Cost	Integrated Electricity and Gas planning
Case50% RET	High	12.00
Case 50%RET_10% higher load	High	12.73
Case 50%RET _10% lower load	High	11.38

TABLE B.1. EXISTING GENERATION CAPACITY AND RETIREMENT

Generators	Existing Capacity *(MW)*	Retirement by 2030 *(MW)*
OCGT	1,440	458
CCGT	1,033	385
Black Coal	7,442	190
Hydro	652	0
Cogeneration	154	0

TABLE B.2. LOCATION AND CAPACITY OF NEW GENERATORS

Bus	**Technology**	**Number**	**Capacity** *(MW)*
1	Wind	1	500
2	OCGT	1	650
	Wind	2	900
3	Wind	1	500
4	Solar PV	1	200
	CCGT	1	800
5	CCGT	1	1300
7	OCGT	1	1000
	CCGT	1	1000
9	Wind	2	750
11	OCGT	3	1800
12	Wind	2	1000
	Solar PV	1	200
13	Wind	1	1000
	Solar PV	1	1500
14	Wind	1	800
	Solar PV	1	900
15	Solar PV	1	1000

TABLE B.3. NEW GENERATORS PARAMETERS

Technology	**Fixed Cost** *($/MW/year)*	**Variable Cost** *($/MWh)*	**Emission Factor** *(tCO2/MWh)*
Wind	41,647	12.5	0
Solar PV	39,322	0	0
OCGT	4,165	10.4	0.52
CCGT	10,412	4.2	0.5

TABLE B.4. NEW TRANSMISSION LINES DATA

From Bus	To Bus	Type	Total capacity (MVA)	Inv. Cost ($ Million)
12	1	275 kV double circuit	2200	165.0
13	2	275 kV single circuit	1100	70.0
13	2	275 kV double circuit	2200	110.0
14	4	275 kV single circuit	1100	140.0
14	4	275 kV double circuit	2200	220.0
15	10	275 kV single circuit	1100	70.0

TABLE B.5. DATA OF EXISTING GAS SUPPLY FACILITIES

Gas nodes	Number of gas facilities	Capacity (*TJ/year*)	Average Operation Cost (*$/TJ*)
NG2	1	24,820	4,620
NG5	1	36,500	3,790
NG9	12	1,510,626	3,636
NG10	12	1,374,050	2,933

TABLE B.6. PROPOSED GAS PRODUCTION FACILITIES PARAMETERS

Gas node	Capacity (*TJ/year*)	Inv. Cost (*Billion $*)	Operation Cost (*$/TJ*)
NG2	5,000	1.95	4,620
NG10	582,175	1.95	3,530

TABLE B.7. PARAMETETERS OF PROPOSED GAS PIPELINES

Origin node	Destination node	Capacity (TJ/day)	Capital Cost (M$)	Operation Cost (M $/p.a.)
NG2	NG6	750	1,207	24.1
NG2	NG6	96	475	9.5
NG10	NG6	750	600	12.0

- A comprehensive electricity and gas integrated planning approach is proposed.
- Stochastic programming is formulated to model uncertainties faced by both systems.
- Impact of high penetration of renewable energy is assessed on planning outcomes.
- The proposed model is validated on a realistic case of Queensland in Australia.
- The usefulness of the given planning model is shown through several analyses.

TABLE 8. EXPECTED CARBON EMISSION AND COST OF EACH TARGET

RET	**Investment Cost**	**Discounted Overall Cost**	**Total Carbon dioxide Emission**
%		*BILLION $*	*MTON OF CO_2*
20	High	6,88	39,0
	Low	6,19	39,0
30	High	8,04	35,5
	Low	7,03	35,6
40	High	9,50	31,0
	Low	8,10	31,1
50	High	12,0	26,1
	Low	9,70	26,1