CAREC Energy Reform Atlas:
Unbundling Case Studies Report

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A.J. Goulding has been engaged as Lead Consultant for the Energy Sector Reform initiative, which the Asian Development Bank ("ADB") has implemented as part of the Central Asia Regional Economic Cooperation ("CAREC") Program. This document, the Case Studies Report, contains the following case studies, which feed into and inform the separate Manual on Unbundling:

- ***Malaysia: an example of corporatization;***
- ***Ontario, Canada: an example of partial unbundling; and***
- ***New South Wales, Australia: an example of full unbundling.***

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List of acronyms

ACCC	Australian Competition and Consumer Commission
ADB	Asian Development Bank
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALD	Availability Liquidated Damages
ALP	Australian Labor Party
BST	Bulk Supply Tariff
CAREC	Central Asia Regional Economic Cooperation
CDM	Conservation and Demand Management
CEO	Chief Executive Officer
CfD	Contract for Difference
COS	Cost of Service
ELEX	Pacific Power Internal Pool Market
EPU	Malaysia Economic Planning Unit
FIT	Feed-in-tariff
FRC	Full Retail Contestability
GA	Global Adjustment
GEA	Green Energy and Green Economy Act

GSO	Grid System Operator
HOEP	Hourly Ontario Energy Price
IBR	Incentive-based Ratemaking
ICPT	Imbalance Cost Pass-through
IESO	Independent Electricity System Operator
IMO	Independent Electricity Market Operator
IPART	Independent Pricing and Regulatory Tribunal
IPP	Independent Power Producer
IR	Incentive Rate-setting
JPPPET	Jawatankuasa Perancangan dan Pelaksanaan Pembekalan Elektrik dan Tarif
KeTSA	Ministry of Energy, and Natural Resources
KLSE	Kuala Lumpur Stock Exchange
LDC	Local Distribution Company
LSS	Large-scale Solar
LTEP	Long-term Energy Plan
MDC	Market Design Committee
MESI	Malaysia Electricity Supply Industry
MEU	Municipal Electric Utility
MPM	Privatization Master Plan
MPPK KWIE	KWIE Fund Management Procedure Manual
MyPOWER	Malaysia Programme Office for Power Electricity Reform
NDC	Nationally Determined Contribution
NEB	National Energy Board
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NSW	New South Wales
OBCA	Ontario Business Corporations Act
OEB	Ontario Energy Board
OPA	Ontario Power Authority
OPG	Ontario Power Generation
PBR	Performance-based Ratemaking
PPA	Power Purchase Agreement
RFP	Request for Proposal
RP	Regulatory Period
RPP	Regulated Price Plan
SB	Single Buyer
SEB	Sarawak Energy Berhad

SESC	Sabah Electricity Sbn Berhad
SESCO	Sarawak Electricity Supply Corporation
ST	Suruhanjaya Tenaga
TFP	Total Factor Productivity
TNB	Tenaga Nasional Berhad

1 Introduction

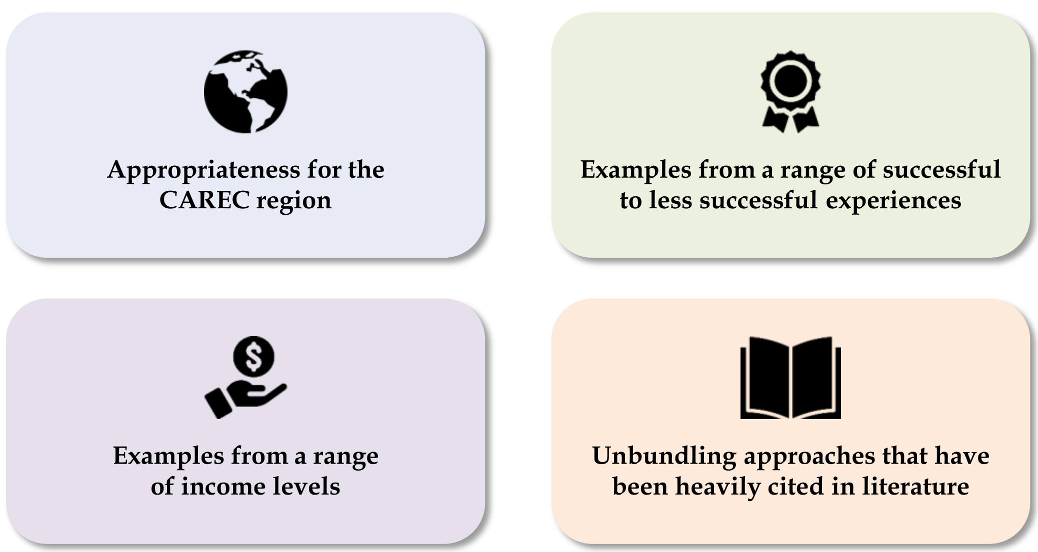
In conjunction with a separate Manual on Unbundling, the following Case Studies Report surveys the various approaches to unbundling that have been implemented around the world, focusing on three particular case studies:

- **Malaysia**, which presents an example of corporatization;
- **Ontario, Canada**, which exemplifies partial unbundling; and
- **New South Wales, Australia**, which presents an example of full unbundling.

1.1 Rationale for selection of case studies

The three cases presented in this Case Studies Report were selected based on a variety of considerations, as summarized in Figure 1 below. The main goal in the selection of case studies was to include jurisdictions that exemplify a diverse range of unbundling approaches (from corporatization to full unbundling), geographies, and stages of economic development, while also focusing on relatively successful jurisdictions from which key lessons could be learned. Ultimately, each of the three jurisdictions selected – Malaysia, Ontario (Canada), and New South Wales (Australia) – offer specific insights for the Central Asian region, which are discussed in further detail below.

Figure 1. Criteria used to select case studies



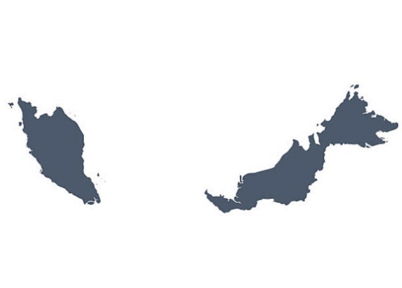
1.2 Comparison of jurisdictions

The selected jurisdictions span a ***range of socioeconomic conditions*** (from an average GDP per capita of $10,402 in Malaysia, to $57,038 in New South Wales, Australia) and a ***range of population sizes*** (from 8.2 million in New South Wales, Australia, to 31.9 million in Malaysia). The jurisdictions also vary widely in terms of the ***size and growth of their electricity markets:*** annual electric generation ranges from 68.6 terawatt-hours ("TWh") in New South Wales, Australia, to

169.5 TWh in Malaysia; Malaysia's electric load is growing almost at the same rate as its GDP growth, while both Ontario, Canada and New South Wales, Australia have seen a slight decrease in load in recent years. A summary of the three selected jurisdictions is presented in Figure 2.

Figure 2. Overview of selected jurisdictions

Malaysia



Key facts	
Population (2019)	31.9 million
GDP growth (CAGR, 2016-2020)	2.8%
GDP per capita (2020)	US$10,402
Installed capacity (2018)	34.0 GW
Net generation (2020)	169.53 TWh
Peak demand (2019)	23.3 GW
Load growth (CAGR, 2016-2019)	2.3%

Ontario, Canada

Key facts	
Population (2020)	14.7 million
GDP growth (2019-2020)	-2.8%
GDP per capita (2020)	US$47,492
Installed capacity (2020)	38.0 GW
Generation (2020)	147.40 TWh
Peak demand (2020)	24.4 GW
Load growth (CAGR, 2015-2019)	-0.4%

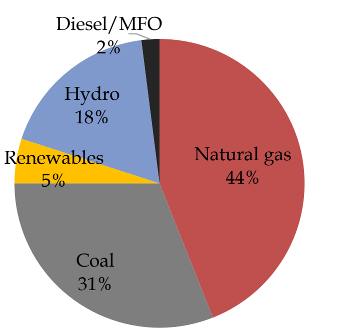
New South Wales, Australia

Key facts	
Population (2020)	8.2 million
GDP growth (2019-2020)	-0.7%
GDP per capita (2020)	US$57,038
Installed capacity (2021)	19.7 GW
Generation (2020)	68.6 TWh
Peak demand (2020)	13.8GW
Load growth (CAGR, 2015-2020)	-0.6%

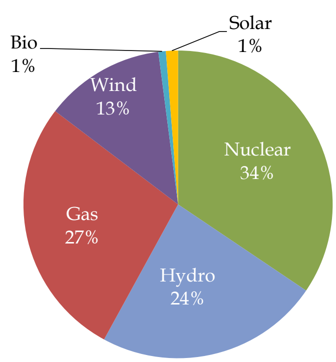
The fuel mix in each of the selected jurisdictions is shown in Figure 3. The electricity systems of both Malaysia and New South Wales, Australia are dominated by fossil fuel-fired generation assets (accounting for 77% of total installed capacity in Malaysia and 63% in New South Wales, Australia). In contrast, installed capacity in Ontario, Canada is comprised mostly of a mix of nuclear (34%), gas (27%), hydro (24%), and wind (13%) assets.

Figure 3. Installed capacity by fuel type for selected jurisdictions

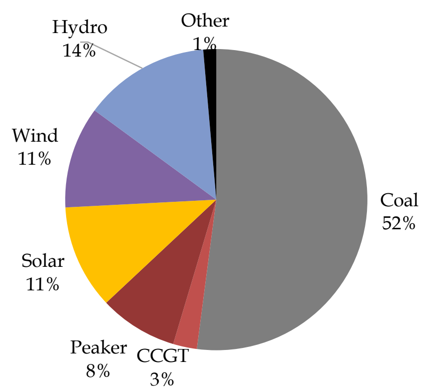
Malaysia (2018)



Ontario, Canada (2020)



New South Wales, Australia (2020)

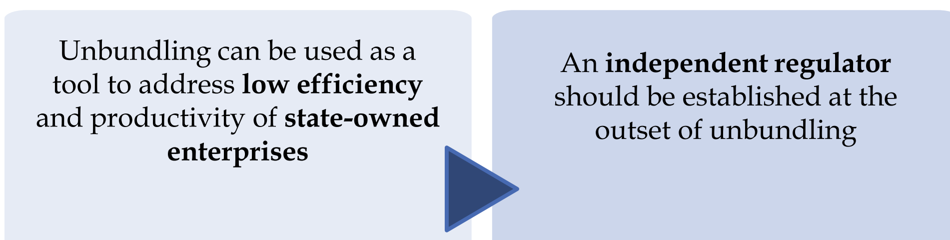


1.3 Overview of the corporatization example: Malaysia

Malaysia's electricity supply industry has evolved from a centralized market structure upon inception to the single buyer model in place today. Privatization efforts began in the late 1980s, when the Government of Malaysia became concerned with the low efficiency and productivity of state-owned enterprises. By 1990, the National Energy Board ("NEB"), which was a state agency responsible for the planning and operation of the electricity supply industry in Peninsular Malaysia, was corporatized as Tenaga Nasional Berhad ("TNB"). In 1993, five companies were granted generation licenses to establish power plants and sell their output to TNB, as the first IPPs in the country. By 2010, the sector continued to evolve, as TNB was functionally unbundled, with its regulatory accounts separated into six business entities: (i) the Transmission Division; (ii) Distribution Network; (iii) Grid System Operator ("GSO"); (iv) Single Buyer ("SB – Operations"); (v) Single Buyer ("SB – Generation"); and (vi) Consumer Services.

Notably, the Single Buyer ("SB") is a ring-fenced department within TNB, and is the authorized entity responsible for electricity planning and management of electricity procurement services in Peninsular Malaysia. SB procures electricity primarily through power purchase agreements with independent power producers, or through service level agreements with TNB generators. SB comprises of six major functions, including: (i) Contract & Resources Management; (ii) Finance & Enterprise Management; (iii) Legal Management; (iv) Market Operation and Assessment; (v) System Planning; and (vi) Technical Advisory & Industrial Development.

Figure 4. Key takeaways from the Malaysia case study



The Malaysia case study provides several key points for the consideration of CAREC members (as illustrated in Figure 4):

- **unbundling can be used as a tool to address low efficiency and productivity of state-owned enterprises:** the Government of Malaysia began exploring the possibility for privatization in the 1980s, amid concerns of the low efficiency and productivity of state-owned enterprises and increasing debt burdens. Privatization efforts were led by a committee comprising of representatives from the Prime Minister's office and the Malaysia Economic Planning Unit. By 1988, the decision to privatize the National Energy Board ("NEB") was finalized, and the unbundling process began; and
- **an independent regulator should be established at the outset of unbundling:** although NEB, the state agency, was corporatized in 1990 and independent power producers ("IPPs") were introduced beginning in 1993, the independent regulator of the sector, Suruhanjaya Tenaga ("ST"), was only established in 2001. This meant the sector (and the newly established partially privatized monopoly) was subject to limited oversight in the

10 years from when the unbundling process began to when the regulator was set up. Once fully operational, ST conducted a review of the electricity tariff structure and a technical study on the performance of the IPPs, which led to the renegotiation of some of the power purchase agreement terms.

1.4 Overview of the partial unbundling example: Ontario, Canada

The electricity market in Ontario, Canada is often characterized as a "hybrid" market, as it contains elements of both a centrally planned and competitive electricity market. Prior to restructuring, Ontario had a vertically integrated, provincially-owned monopoly, Ontario Hydro, which was responsible for generation, transmission, and distribution. In the 1990s, Ontario Hydro suffered major cost overruns, excessive debt, and poor nuclear performance, which caused electricity rates to rise by nearly 30%.

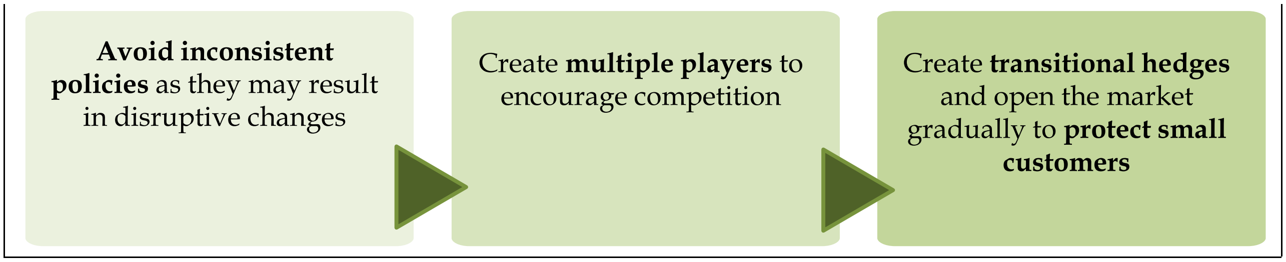
By 1996, Ontario began considering the restructuring of its electricity sector – policymakers called for the injection of competition and suggested the possibility of breaking Ontario Hydro into a number of competing generation companies, some of which would remain publicly owned. Pursuant to the *Electricity Act* of 1998, Ontario Hydro was eventually separated into five companies:

- **Ontario Power Generation ("OPG"):** which assumed Ontario Hydro's generation assets and the direct customer, retail, and wholesale operations;
- **Hydro One:** which inherited the transmission and distribution business of Ontario Hydro;
- **Independent Electricity Market Operator:** which assumed responsibility for administering the electricity markets and directing the operation of the transmission grid, and was later renamed the Independent Electricity System Operator ("IESO") in 2005;
- **Ontario Electricity Financial Corporation:** which assumed all other assets and liabilities of Ontario Hydro; and
- **Electricity Safety Authority:** which is responsible for enacting regulations on a broad range of operational matters relating to the generation, transmission, distribution, retail, or use of electricity in Ontario.

Currently, competitive power generators bid into and receive dispatch instructions from a wholesale market administered by the IESO, with retail choice at the consumer level. However, Ontario's electricity market still largely consists of a principal buyer,[1] with this role being served by the IESO after it absorbed the Ontario Power Authority. Some generation assets were privatized, and the bulk of new build has been privately owned. The primary transmission owner also serves a significant number of distribution customers.

Figure 5. Key takeaways from the Ontario (Canada) case study

[1] A principal buyer is akin to a single buyer, but exists in a market structure where private, bilateral contracting is possible.



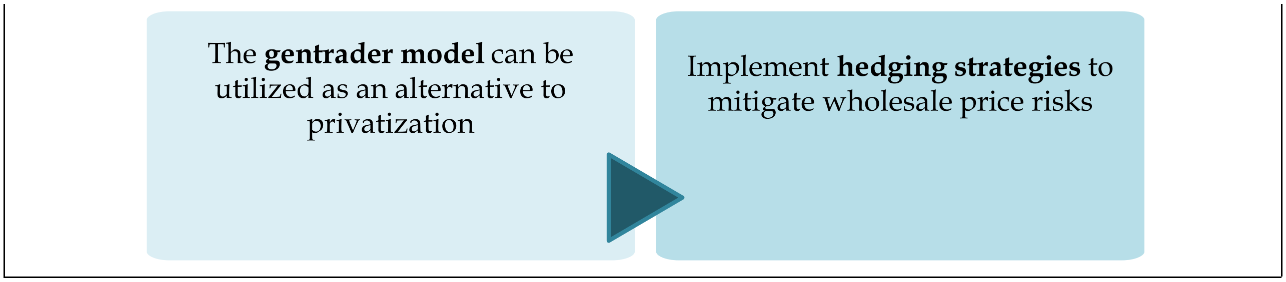
The Ontario (Canada) case study provides several key points for the consideration of CAREC members (as illustrated in Figure 5):

- **avoid inconsistent policies as they may result in disruptive changes:** in many ways, Ontario's unbundling efforts were guided by the right objectives – developing full wholesale and retail competition, maximizing liquidity in the wholesale market through participation of merchant generators, and diverting investment risk away from consumers. However the implementation approach did not offer adequate transitional mechanisms to consumers, which resulted in public backlash and ultimately, political intervention resulting in a partial reversal of government policy away from liberalization. This policy reversal created uncertainty in the sector, and has been largely responsible for the low levels of market-driven investment;
- **create multiple players to encourage competition:** there was a lack of government will to sell off OPG's generation plants to add more market players and create a truly competitive structure. This was due in part to resistance from the incumbent and unions; and
- **create transitional hedges and open the market gradually to protect small customers:** spot market prices can be unpredictable and relatively high. The Ontario case study demonstrates that restructuring without appropriate hedge strategies can be risky, and highlights that vesting contracts have a role in restructuring to competitive markets. In addition, because all customers were exposed simultaneously to competition, small customers were hurt the most from this price volatility.

1.5 Overview of the full unbundling example: New South Wales, Australia

New South Wales ("NSW") is a pioneer in electricity restructuring in Australia. Prior to the reform process, electricity in southeast Australia was provided by vertically integrated, centrally planned, state-owned monopolies operating in each state and territory. Electricity market restructuring in NSW began in the 1990s and was driven in large part by inefficient investment and poor operational performance by state-owned generators. Over the period from 1991 to 1996, three generation businesses were legally unbundled, transmission assets were separated into TransGrid, and the fragmented distribution sector was consolidated into six distribution businesses. Full unbundling occurred later between 2010 and 2014, with privatization of the generation and retail sectors.

Figure 6. Key takeaways from the New South Wales (Australia) case study



The New South Wales (Australia) case study provides several key points for the consideration of CAREC members (as illustrated in Figure 6):

- **the gentrader model can be utilized as an alternative to privatization:** privatization in NSW has received constant opposition, particularly from labor and trade unions, since the 1990s. However, the government realized the importance of private sector participation in building a competitive electricity market and so employed the gentrader model to contract the electricity dispatch and trading rights out to the private sector. NSW's gentrader model, which is described in detail in Section 4.3.2, essentially established virtual generators whereby the risks and rewards (but not the physical asset) were auctioned off to a third-party, which then traded the output. The model introduced competition in the market, helped eliminate the government's exposure to electricity trading risks, and paved the way for further privatization; and
- **implement hedging strategies to mitigate wholesale price risks:** NSW applied key transitional models such as vesting contracts (transitional contracts between generators and load) to mitigate the wholesale price risks and transitional default tariffs for customers (prior to choosing their own retailers). These specific design elements reduced market risks, especially for smaller consumers who wished to remain regulated.

2 Malaysia (corporatization)

Malaysia has a dynamic electricity supply industry which evolved from a centralized market structure upon inception to the single buyer model in place today. Through this evolution, the Government of Malaysia has sought to introduce reforms to improve efficiency and governance over the sector. The following case study reviews the electricity sector in Malaysia today, its regulatory structure, and the history of restructuring in the sector, with a focus on the corporatization efforts which began in the late 1980s.

2.1 Overview of the Malaysia market

Malaysia's electricity sector reflects the diverse geography of the state. There are three supply regions with their own unique characteristics: Peninsular Malaysia, Sabah, and Sarawak. In 2018 (i.e., the most recent data available from the regulator), Peninsular Malaysia accounted for 82% of GDP and 79% of total electricity consumption. In the same year, Sabah and Sarawak accounted for 7% and 10% of GDP, as well as 4% and 17% of electricity consumption, respectively.[2]

Sabah and Sarawak are located on the island of Borneo and do not share a land border with Peninsular Malaysia. Accordingly, three utilities are responsible for the transmission and distribution of electricity to these three regions: Tenaga Nasional Berhad ("TNB") serves Peninsular Malaysia, Sabah Electricity Sbn Berhad ("SESB") serves Sabah, and Sarawak Energy Berhad ("SEB") serves Sarawak. In 2019, TNB's peak demand reached 18,566 MW, while SESB and SEB recorded peaks of 1,001 MW and 3,777 MW, respectively.

Malaysia's supply mix is diverse and comprises of a substantial amount of fossil fuel-fired generation, including nearly 15 GW of natural gas-fired generation (or 44% of total installed capacity) and 10.3 GW of coal-fired generation (31% of total capacity). Other fuel sources include hydroelectric generation, which accounts for over 6 GW (18% of total capacity), with other renewables such as solar and biomass comprising 1.7 GW (5% of total capacity).[3] Independent power producers ("IPPs") comprise most of the total ownership of capacity, accounting for 60% of all generation capacity, with TNB the second largest owner at 15%, and SEB at 14%.[4]

The sector is overseen by Suruhanjaya Tenaga ("ST"), the Energy Commission, which was established in 2001 by the Energy Commission Act of 2001 with a mandate to regulate the "*electricity and piped gas supply industries*" in Peninsular Malaysia and Sabah.[5] ST is responsible for setting tariffs, setting performance indicators, and safety regulation in the electricity and natural gas sectors; it's mandate is carried out by three broad groups: (i) Economic Regulation, (ii) Technical Regulation, and (iii) Safety Regulation.

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[2] Suruhanjaya Tenaga. *Malaysia Energy Statistics Handbook 2020.*

[3] Ibid.

[4] Ibid.

[5] Suruhanjaya Tenaga website. *About Us.* Accessed at: <https://www.st.gov.my/en/details/aboutus/1>

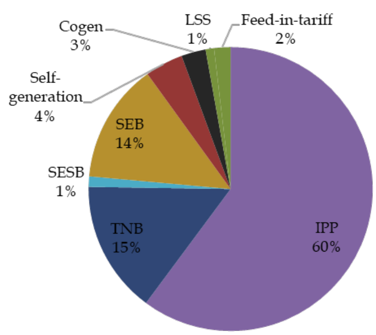
In summary, Figure 7 below provides a snapshot of the electricity sector in Malaysia.

Figure 7. Malaysia market snapshot

Malaysia

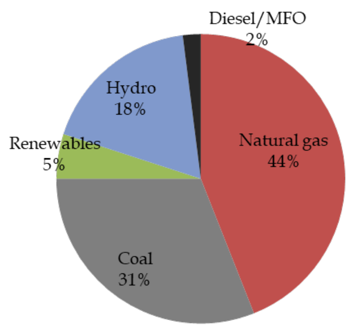
Key facts	
Population (2019)	31.9 million
GDP growth (CAGR, 2016-2020)	2.8%
GDP per capita (2020)	$10,402
Installed capacity (2018)	33,990 GW
Energy sales (2020)	147.6 TWh
Peak demand* (2019)	23,344 GW
Load growth* (CAGR, 2016-2019)	2.3%
Distribution lines (2019)	730,619 km
Transmission lines (2019)	31,621 km

Generation owners by installed capacity (2018)



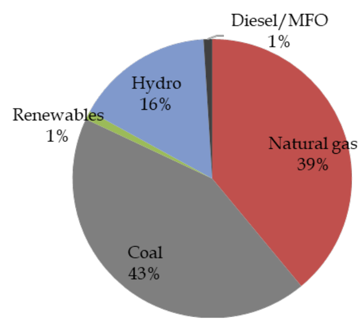
33,991 MW

Installed capacity by fuel type (2018)



33,991 MW

Net generation by fuel type (2020)



169,529 GWh

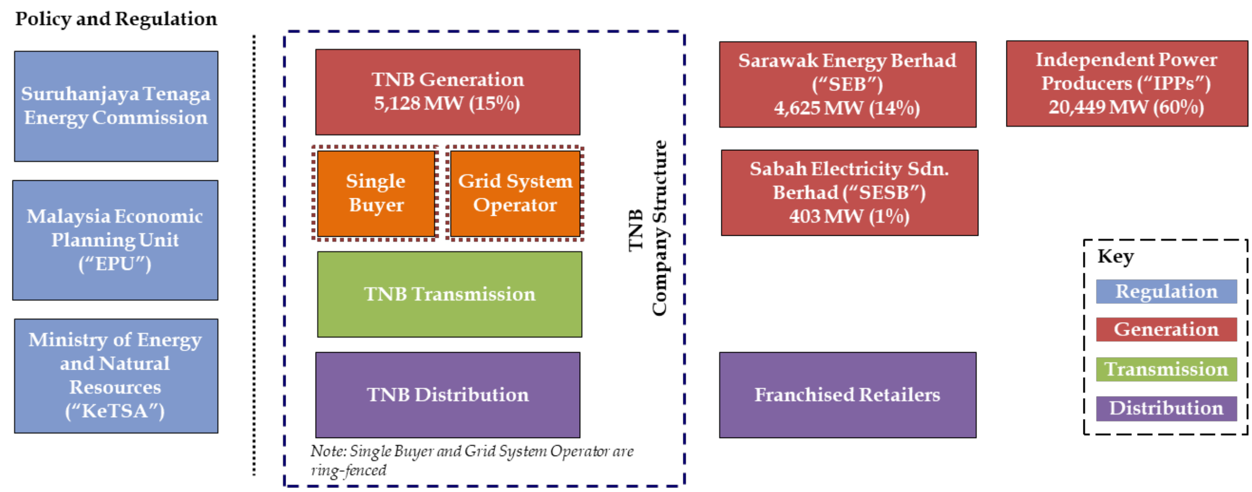
* Non-coincident peak demand for TNB, SEB and SESB.

Sources: World Bank data; Suruhanjaya Tenaga data.

2.2 Malaysia's current institutional and legal framework

There are several key institutions responsible for the energy sector in Malaysia, including the regulator, Suruhanjaya Tenaga ("ST"), the Ministry of Energy, and Natural Resources ("KeTSA"), and the Malaysia Economic Planning Unit ("EPU"). These three oversight agencies are responsible for the policy and regulation of the sector participants, which include TNB, SEB, SESB, and several IPPs and franchised retailers. Figure 8 below provides a summary of the key entities in the electric sector, which are described further in the subsections that follow.

Figure 8. Malaysia market structure



Source: LEI analysis; Suruhanjaya Tenaga data

2.2.1 Regulation and policy setting

In Malaysia, the key agencies with respect to regulation and policy setting and implementation are KeTSA and ST. **KeTSA**'s mission with respect to the electricity sector is "*managing the electricity supply industry strategically by optimizing the renewable energy and energy efficiency to ensure reliable, affordable and sustainable electricity supply services*."[6] KeTSA's role is to establish major policies in the sector, with ST among the implementing agencies in the government. The composition of ST is also the responsibility of the Minister in charge of Energy – i.e., the Minister at KeTSA.

ST comprises of a Chairman, a Chief Executive Officer ("CEO"), three members representing the government, and not more than six other members who are considered to have "*knowledge and experience in matters relating to finance, engineering, business or administration or other relevant areas*."[7] The regulator was formed as a result of the Energy Commission Act of 2001, with a mandate to regulate the electricity and piped gas sectors in Peninsular Malaysia and Sabah. ST began its operation in January 2002, taking over a role previously undertaken by the Department of Electricity and Gas Supply. As described by ST, its economic regulation role entails regulation of electricity and piped gas tariffs and the quality of supply services, as well as "*promot[ing] competition and prevent[ing] the misuse of monopoly or market power*."[8] Currently, ST comprises of eight divisions that report to the CEO, with its mandate derived from several enabling laws, including: the Electricity Supply Act 1990, the Licence Supply Regulation 1990, the Gas Supply Act 1993, the Electricity Regulation 1994, and the Gas Supply Regulation 1997.

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[6] KeTSA. *KeTSA Background.*

[7] Suruhanjaya Tenaga website. *Energy Commission members.* Accessed at: <https://www.st.gov.my/en/details/aboutus/5>

[8] Suruhanjaya Tenaga. *2019 Annual Report.* 2020.

In Peninsular Malaysia, long-term generation planning and policy development is undertaken through a cross-cutting committee known as the Jawatankuasa Perancangan dan Pelaksanaan Pembekalan Elektrik dan Tarif ("JPPPET"). JPPPET was established in November 1997 with the aim to plan, coordinate, and identify electricity supply requirements to meet electricity demand in Peninsular Malaysia. The committee is chaired by the Minister responsible for Energy – currently KeTSA – and comprises of representatives from all relevant ministries, agencies, and utilities. The main output from this committee is a long-term generation development plan, which is approved at an annual committee meeting and is published to provide long-term direction for the sector.[9] The most recent plan studied a planning horizon of 2021-2039, projecting demand growth of 0.6% per year between 2021 and 2030, and 1.8% per year between 2030 and 2039. The plan also set a target for new generation capacity of 6 GW by 2030, to enable Malaysia to meet its demand growth needs and renewable energy targets.[10]

In Sabah, a similar effort is undertaken by the State Planning and Implementation of Electricity Supply and Tariffs Committee, which is co-chaired by the Minister responsible for Energy and the Chief Minister of Sabah. The most recent plan for Sabah, covering the 2020-2030 period, prioritizes strengthening the state transmission network and developing renewable energy. Specifically, these efforts are anticipated to involve the development of two high-voltage transmission lines and an additional 100 MW of installed capacity by 2024.[11]

2.2.2 Regulatory oversight of charges

Tariff setting in Malaysia is the responsibility of ST, and rates for customers in Peninsular Malaysia are set under an incentive-based ratemaking ("IBR") framework. The IBR framework was introduced in 2014 and involves a price cap mechanism set over a three-year period, referred to as the Regulatory Period ("RP"). RP1 was in place between 2014 and 2017, while RP2 was effective between 2018 and 2020.[12]

One feature of the IBR framework is the Imbalance Cost Pass-Through ("ICPT"), which involves a bi-annual review of fuel prices that are fixed under the IBR framework. The ICPT is a true-up mechanism that can either result in a surcharge or a rebate, depending on the actual cost of fuel, relative to the fuel costs set in the tariff. As a tool to stabilize prices for customers under the ICPT, the Government of Malaysia established an Electricity Industry Fund (Kumpulan Wang Industri Elektrik, or "KWIE"). The KWIE is used to cover a portion of the actual ICPT in the event of a surcharge. ST oversees the KWIE, which is funded through an established formula from generation licensees – currently set at 1.25% of revenue less audited fuel costs.[13] ST's oversight of the fund is guided by the KWIE Fund Management Procedure Manual ("MPPK KWIE"), which establishes protocols and internal controls.

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[9] JPPPET. *Report on Peninsular Malaysia Generation Development Plan 2020 (2021-2039)*. March 2021.

[10] Ibid. P. 9.

[11] Suruhanjaya Tenaga. *2019 Annual Report.* 2020. P. 93.

[12] Ibid. P. 110.

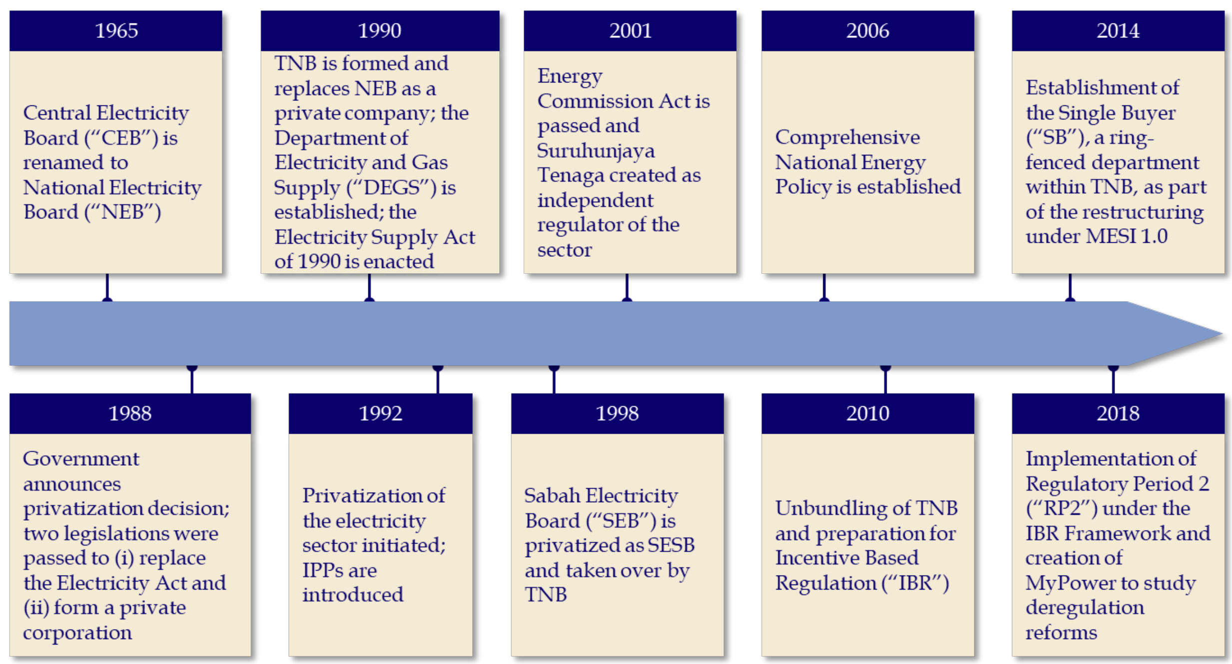
[13] Ibid. P. 126.

In Sabah, IBR is currently under consideration. However, an implementation date for a regulatory period similar to that for TNB in Peninsular Malaysia has yet to be established.

2.3 History of restructuring

Malaysia's electricity sector has evolved considerably since the establishment of the National Energy Board ("NEB") in 1965. Key events during that period include the corporatization of the NEB in 1990 following the Electricity Act of 1988, the introduction of IPPs in 1992, and the establishment of an independent regulator (ST) in 2001. Figure 9 below summarizes these key events, which are discussed in the subsections that follow.

Figure 9. Timeline of the evolution of Malaysia's electricity sector



Source: LEI analysis; Suruhanjaya Tenaga annual reports; TNB annual reports

2.3.1 Before 1988: preparation for corporatization

Prior to the shift towards privatization in the sector, the NEB was responsible for the planning and operation of the electricity supply industry in Peninsular Malaysia; in Sabah, this function was undertaken by a similar agency, the Sabah Electricity Board. The Ministry of Energy, through the Electrical Inspectorate Department, was responsible for licensing of private generation, as well as the safety of electrical installations and equipment. In Sarawak, the Sarawak Electricity Supply Corporation ("SESCO") was responsible for provision of electricity to all customers, and the region's State Inspectorate was responsible for licensing and safety.[14]

[14] Suruhanjaya Tenaga. *Energy Malaysia: Volume 21*. 2021.

In the 1980s, the Government of Malaysia became concerned with the low efficiency and productivity of state-owned enterprises coupled with increasing debt burdens, and established a policy for privatization. The government established a privatization committee led by the Prime Minister's office and the EPU and announced the policy in 1983. In 1985, the EPU released the Guidelines on Privatization (or "Privatization Document"), which identified the objectives of privatization including "*relieving the financial and administrative burden of the government*."[15]

In general, four methods were employed by the government in its privatization scheme: (i) sale of equity stake, (ii) sale of assets, (iii) leasing of assets, and (iv) establishment of management contracts. Spearheaded by the EPU, which would later create the Privatization Master Plan ("MPM") in 1991, the decision to privatize the NEB was made in May 1988.[16]

2.3.2 1988 to 2000: corporatization is implemented and IPPs are introduced

Once the decision to privatize the NEB was made, the first step towards implementation was the corporatization of the state agency. In 1990, the Electricity Supply (Successor Company) Act 1990 (Act 448) was passed. The Act mandated that the NEB be corporatized as Tenaga Nasional Berhad on September 1st, 1990, which became a company wholly owned by the government. TNB was eventually identified for a sale of equity, and subsequently a stake of 30% was floated on the Kuala Lumpur Stock Exchange ("KLSE") in 1992; the Ministry of Finance retained a 70% stake in the entity.[17]

Later, a similar framework was utilized for the Sabah Electricity Board, which was privatized in 1998 as SESB, with TNB as its majority shareholder with a stake of 80%. In Sarawak, the Sarawak State Government divested 50% of its equity in SESCO to the private sector later in the decade.

In 1993, five companies were granted generation licenses to establish power plants and sell to TNB, as the first IPPs in the country.[18] By 2000, an additional ten licenses had been granted, with private power producers comprising 30% of total supply in Malaysia. Commentators deemed the terms of the "first generation" IPPs to be too favorable for the generators, and these terms would later come to be renegotiated in 2006 under the purview of ST.[19]

2.3.3 2001 to 2010: independent regulator is established

The Energy Commission Act 2001 was approved by Parliament to establish ST to take over the functions of the Department of Electricity and Gas Supply and act as an independent regulator over the electricity and piped gas sectors. Fully operational in 2002, the regulator did not review the electricity tariff structure until 2005. This was followed by a technical study on the

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[15] Woon, Toh Kin. "Privatization in Malaysia: Restructuring or Efficiency?." *ASEAN Economic Bulletin* (1989): 242-258.

[16] TNB website. *About TNB: History.*

[17] In recent years, government ownership of TNB has been maintained at a level between 60-70%. (Source: S&P Capital IQ)

[18] Smith, Thomas B. "Privatising electric power in Malaysia and Thailand: politics and infrastructure development policy." *Public Administration and Development* 23.3 (2003): 273-283.

[19] Suruhanjaya Tenaga. *Energy Malaysia: Volume 21.* 202.1

performance of IPPs in 2006, which preceded the renegotiation of some of the terms of the PPAs between TNB and the IPPs.[20]

By the end of the decade, ST was also tasked with oversight of the competitive bidding for generation projects, which began in 2010. As policymakers developed a strategic direction for the sector, in 2009, the government endorsed the Malaysia Electricity Supply Industry ("MESI") 1.0 initiative. The MESI 1.0 initiative was to be led by the newly formed Malaysia Programme Office for Power Electricity Reform ("MyPOWER") Corporation. MyPOWER, a special purpose agency, was tasked with studying and detailing the reforms which were to be carried out between 2010 and 2014, with the objectives of improving the tariff mechanism, enhancing fuel supply and security, and achieving governance effectiveness in managing the power sector.[21,22]

2.3.4 After 2010: unbundling of TNB and preparation for IBR

Since 2010, the sector has continued to evolve with further unbundling initiatives undertaken; the most significant development in recent years has been the implementation of IBR in Peninsular Malaysia. As part of this effort, TNB was functionally unbundled as its regulatory accounts were separated into six business entities, namely: (i) the Transmission Division; (ii) Distribution Network; (iii) Grid System Operator ("GSO"); (iv) Single Buyer ("SB – Operations"); (v) Single Buyer ("SB – Generation"); and (vi) Consumer Services.

The Single Buyer ("SB") is the authorized entity responsible for electricity planning and management of electricity procurement services in Peninsular Malaysia. SB procures electricity primarily through power purchase agreements with independent power producers, or through service level agreements with TNB generators. SB comprises of six major functions, including: (i) Contract & Resources Management; (ii) Finance & Enterprise Management; (iii) Legal Management; (iv) Market Operation and Assessment; (v) System Planning; and (vi) Technical Advisory & Industrial Development. Importantly, SB was set up as a ring-fenced department within TNB. Ring-fencing refers to the "*separation of accounts, business activities and governance of an entity, without being completely taken out of the company,*" and typically occurs when one corporate entity is providing both regulated and unregulated services.[23] For TNB, the objective of ring-fencing was to remove potential conflicts of interest and improve transparency in the sector.

Renewable development has also been substantial since the MESI 1.0 initiative. For example, in 2019, the Large-Scale Solar ("LSS") program awarded 490 MW of new generation capacity, bringing the total solar capacity in Peninsular Malaysia to over 600 MW. This renewable development is within the context of Malaysia's climate goals, which includes a commitment to increase the share of renewables to 31% by 2025. In addition, Malaysia has committed to a

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[20] Ibid. P. 6.

[21] Sopian, Aizuddin Mohd, Joon B. Ibrahim, and Nor Ziha Zainol Abidin. "International Competitive Bidding for New Generation Capacity: The Malaysia's Experience." *Proc. 2013 Scientific Cooperations International Conference in Electrical and Electronics Engineering*. 2013.

[22] Shamsuddin, Amanuddin et al. *Electricity supply industry reform and design of competitive electricity market in Malaysia.* Oxford Institute for Energy Studies. OIES Paper: EL 44. January 2021.

[23] Single Buyer website. *What is Ring-fencing?* Accessed at: <https://www.singlebuyer.com.my/ringfencing.php>

reduction of greenhouse gas emissions to 45% below 2005 levels, according to its COP21 Nationally Determined Contribution ("NDC").[24]

[24] United Nations Framework Convention on Climate Change. *Intended Nationally Determined Contribution of The Government of Malaysia.* November 2015.

3 Ontario, Canada (partial unbundling)

Ontario's electricity system is often characterized as a "hybrid" market, as it contains elements of both a centrally planned and competitive electricity market. This characteristic is the direct result of how Ontario's incomplete restructuring policies evolved over time. Ontario's restructuring in 2002 represents an attempt by a jurisdiction to move from a regulated integrated government monopoly to a competitive market. A key lesson for other jurisdictions is that the failure to institute transitional mechanisms increases the risk of political influence in the event of price volatility. The current institutional structure alleviates some of the problems that arose following restructuring, but at the expense of genuine market competition and cost efficiency. Going forward, the province's Independent Electricity System Operator ("IESO") continues to explore avenues to increase competition and cost efficiency, and transition away from this "hybrid" model – but successfully achieving this task continues to pose its challenges.

3.1 Overview of the Ontario market

Prior to restructuring, Ontario had a vertically integrated provincially-owned monopoly, Ontario Hydro, which was responsible for generation, transmission, and distribution. Currently, power generators bid into and receive dispatch instructions from a wholesale market administered by the IESO, with retail choice at the consumer level. However, Ontario's electricity market still largely consists of a principal buyer, with this role being served by the IESO, which in practice has been heavily influenced by the Ontario government.

Generation

Ontario has operated what has generally been an energy-only wholesale electricity market since May 2002, following the restructuring of the vertically integrated Ontario Hydro.[25] Presently, the province's installed capacity consists primarily of nuclear (34%), natural gas (27%), hydro-electric (24%), and wind (13%). Approximately 54% of this generating capacity is controlled by the provincially-owned Ontario Power Generation ("OPG"), which holds the generation assets that remained of the former Ontario Hydro, as well as certain new-build gas-fired generation assets that have been procured following unbundling. The second largest player in Ontario's electricity generation is Bruce Power, which operates approximately 19% of Ontario's capacity through the Bruce nuclear facilities, which are leased from OPG. Independent power producers ("IPP") make up the remainder of asset owners, at around 17% of ownership in capacity terms.

Ontario's supply-side dynamics have been heavily influenced by government policy over the past two decades. This has included establishing centralized procurement under long-term power-purchase agreements ("PPA"); large-scale procurement of new renewable resources above market feed-in tariff ("FIT") rates under long-term contracts (mostly wind and solar, with a small

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[25] In December 2020 the IESO held its first "capacity auction." Practically speaking, the IESO's capacity auction still functions primarily as a demand response auction, as demand response resources made up around 80% of the capacity that cleared the first auction, which in turn made up only around 2% of Ontario's total installed capacity from all resources. This capacity auction functions similar to a short-term balancing auction, and does not provide the proper price signal to incent large new-build conventional generation.

amount of hydro and bioenergy); as well as early retirement of coal-fired assets[26] and procurement of new gas-fired resources under long-term contracts to substitute the retired coal generation. Overall, although generators have open access to the transmission network and can theoretically operate without some form of guaranteed revenue, in practice Ontario's supply almost entirely operates under either long-term contract with the IESO or under regulated rates (specific to most of OPG's hydroelectric assets and all its nuclear assets).

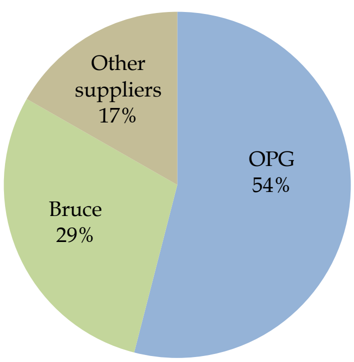
Figure 10. Ontario market snapshot

Ontario

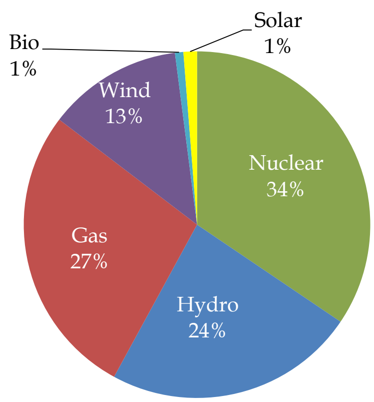
Macroeconomic indicators	
Population (2020)	14.7 million
Population growth rate (19-20)	1%
GDP per capita (2020)	C$60,273
GDP growth (19-20)	-2.8%

Electricity sector statistics	
Tx-connected Installed capacity (2020)	37,978 MW
Peak demand (2020)	24,446 MW
Generation (2020)	147,400 GWh
Load growth (15-19)	-0.4%

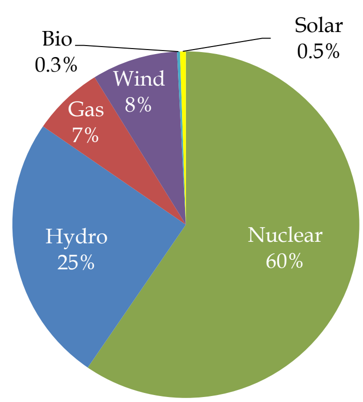
Top market players by capacity



Installed capacity by fuel type



Generation by fuel type



Note: As of Q2 2021, Ontario also had 3,577 MW of distribution-connected generation under IESO contract. The majority of this capacity consists of solar (2,195 MW), followed by wind (590 MW), with hydro, gas, and bioenergy resources making up the remainder.

Sources: Ontario Ministry of Finance; IESO.

Despite limited or negative load growth from 2015 to 2019 (averaging -0.4% per year), Ontario's installed capacity has grown over the same period by 1.6% per year. While a portion of this capacity increase has been justified by the decision to close all of Ontario's coal-fired power

[26] By April 2014, Ontario became the first market in North America to fully eliminate coal as a source of electricity generation. Source: Ontario Ministry of Energy. *Creating Cleaner Energy in Ontario – Province has Eliminated Coal-Fired Generation.* April 15, 2014.

stations (last unit retired in 2014) and bring more new renewable resources online, excess supply was a persistent issue over the past five years.

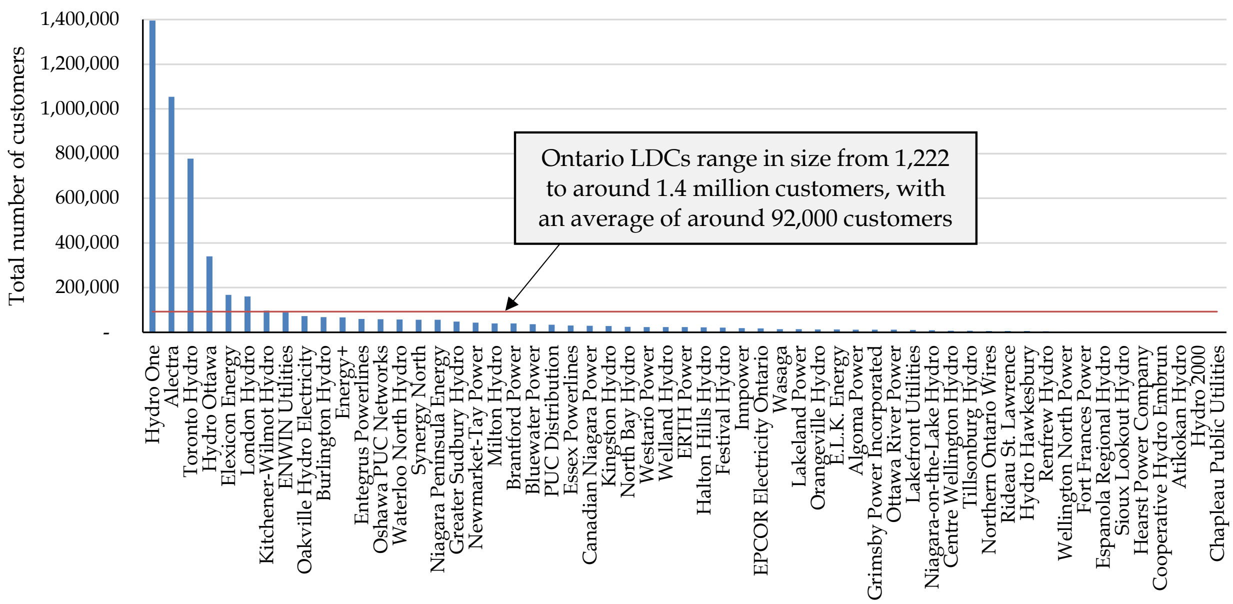
Transmission

Hydro One Networks Inc. ("Hydro One") is the owner and operator of 97% of the transmission assets in Ontario. It is a wholly owned subsidiary of Hydro One Limited, which was initially established as an Ontario-government owned corporation, but in 2015 was reorganized into a publicly traded company; as of March 31st, 2021, the government of Ontario retains a 47.2% ownership of Hydro One Corporation's common shares.[27] Hydro One's transmission system is also connected to the five other small transmitters which represent the remaining 3% of licensed transmission facilities in Ontario.

Distribution

Hydro One is also the largest local distribution company ("LDC") in Ontario, serving over 25% of customers primarily in rural areas, with its service territory covering approximately 75% of the geographic area of the province. In total, there are around 57 distribution companies in Ontario, which mostly serve urban customers and are largely municipally owned. Aside from Hydro One, the other major distribution companies by market share include Alectra Utilities (20%), Toronto Hydro (15%), and Hydro Ottawa (6%). Figure 11 shows the total number of customers by LDC as of 2019.

Figure 11. Total number of customers by LDC (as of 2019)



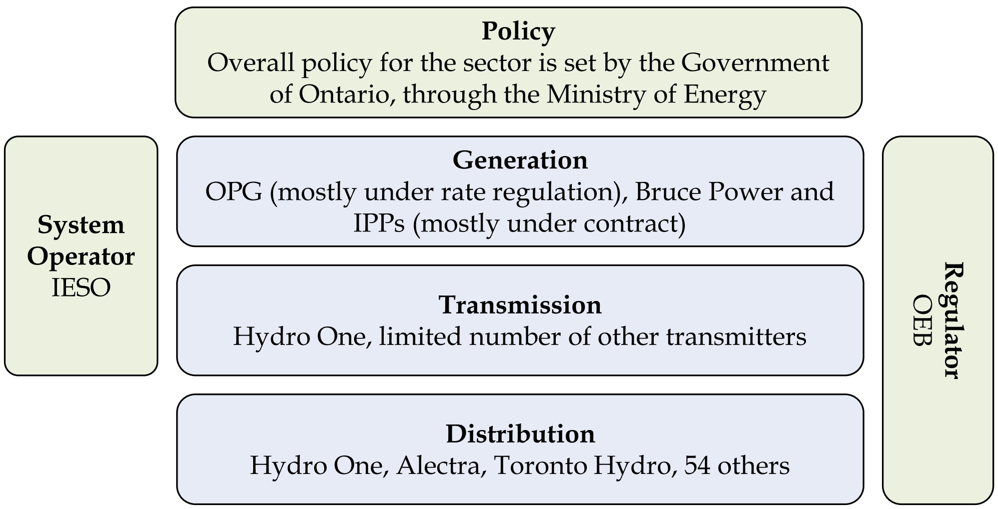
Source: OEB. *Yearbook of Electricity Distributors for 2019/20*. August 13, 2020.

[27] Hydro One Limited. *Quarterly Report for the First Quarter of 2021*. May 7, 2021.

3.2 Ontario's current institutional and legal framework

The institutional arrangements in Ontario allow the provincial government to control the overarching direction of the energy sector, mostly through ministerial directives and other avenues. This section provides an overview of the regulatory bodies in Ontario's electricity sector and their responsibilities in administering it. Figure 12 summarizes the key roles of all the entities in Ontario's electricity sector.

Figure 12. Key roles of entities in Ontario's electricity sector



3.2.1 Regulation and policy setting

The **Government of Ontario** has historically been responsible for developing the overarching direction of energy plans for the province and long-term policy, mostly through the **Ministry of Energy**. Upon the approval of Cabinet, the Minister of Energy can issue ministerial directives to the Ontario Energy Board ("OEB") and the IESO, and each is legally obligated to implement such policy directives.

The **IESO** is a not-for-profit corporation licensed by the OEB to conduct the role of a system operator, for example by overseeing Ontario's electricity market, operating the transmission system, and balancing the demand for electricity with supply. However, the IESO, at the government's direction, has also supported the implementation of energy plans and made decisions regarding new generation procurement, longer-term planning and procurement to address needs, market development, and conservation and demand management ("CDM") programs, and serves as the contractual counterparty for around 26.7 GW of capacity in the province.[28]

[28] IESO. *A Progress Report on Contracted Electricity Supply: Second Quarter 2021*. June 2021.

The **OEB** is the ostensibly independent tribunal that is responsible for regulating Ontario's electricity and natural gas sectors. The OEB regulates the IESO, as well as transmission and distribution companies. The OEB also regulates the cost of power from certain OPG assets (specifically certain hydro facilities and all of OPG's nuclear assets), but the cost of power agreements with non-utility suppliers are not subject to OEB regulation. Additionally, the OEB creates transmission system standards, manages rate hearings and evaluates appeals from stakeholders, sets prices for consumers under the Regulated Price Plan ("RPP"), issues licenses, and oversees electricity retailers. As the OEB's objective includes facilitating innovation in the electricity sector, it also has a role in policy development, although this has generally been focused on electricity delivery (i.e., distribution and transmission).

3.2.2 Regulatory oversight of charges

Before the breakup of Ontario Hydro, electricity rates were determined purely on a cost-of-service ("COS") basis, with no consideration about whether the costs incurred were reasonable or billed to consumers over an appropriate period. The OEB at that time did not regulate electricity. Major cost overruns resulted in increasing prices in the early 1990s before the government froze the price of electricity for several years regardless of costs.

With unbundling, the OEB's mandate (which previously focused solely on gas) was expanded to regulation in the electricity sector (commencing in 1999), including setting electricity delivery rates. Currently, the OEB follows a quasi-judicial process that is open to public participation when setting these rates, which is conducted for distributors, transmitters, and specific generation assets owned by OPG. Entities that are regulated by the OEB are allowed to earn a reasonable rate of return on their capital investments once the OEB approves their rates and deems the investment appropriate given future demand for electricity. The approach the OEB takes in rate regulation is summarized below, with all entities falling under some form of incentive rate-setting ("IR"):[29]

- **distributors:** electric distributors are given three options on how to set their rates, based on the method that best meets their requirements and circumstances: (i) Price Cap IR, (ii) Custom IR, and (iii) Annual IR Index. Under Price Cap IR, base rates are set through cost of service in the first year, and formulaically for the subsequent four years. Under Custom IR, rates are set "for five years considering a five-year forecast of the utility's costs and sales volumes." Annual IR Index is the simplest approach, with rates adjusted formulaically every year.[30] This framework calls for distributors to focus on customer requirements and to demonstrate that their investment plans support cost-effective planning and operation of the distribution network;
- **transmission:** individual rates are not set for each transmitter. Instead, the revenue requirement for each is approved by the OEB, which in turn is used to establish the uniform transmission rates which apply for transmission throughout the province. In

[29] OEB. *Handbook for Utility Rate Applications*. October 13, 2016.

[30] Ibid.

adjusting its revenue requirement, transmitters can choose either (i) Custom IR, or (ii) a Revenue Cap IR;[31] and

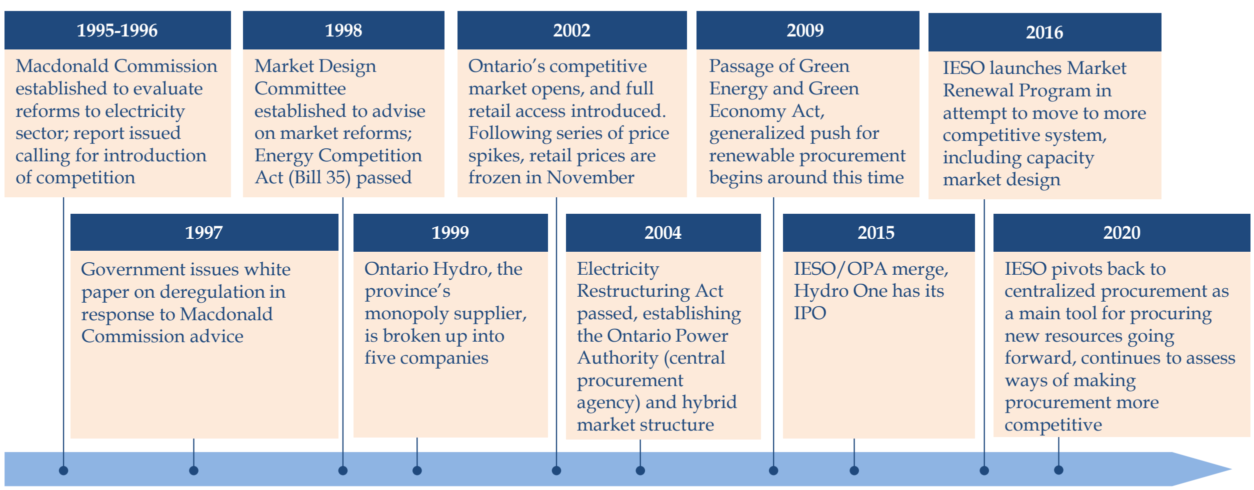
- **generation:** the OEB's rate regulation extends to most of OPG's hydroelectric facilities and all of its nuclear facilities. Together, these regulated facilities supplied just over half of Ontario's total electricity in 2020. Regulated hydro facilities take a Price Cap IR approach, while regulated nuclear is based on Custom IR. Aside from these OPG facilities, the remainder of Ontario's electricity supply is not under OEB rate regulation.

In 2005, the OEB also initiated the RPP, which provides a set electricity price options that applies to residential and small commercial customers. The RPP is reviewed twice per year and may change based on an updated OEB forecast and any accumulated differences between the amount that consumers paid for electricity and the amount paid to generators in the previous period.

3.3 History of restructuring

The Ontario electricity market has undergone a number of important developments over its unbundling timespan and beyond, including the regulation of a large portion of OPG's generation assets, solicitation of new electricity supply from various sources through direct procurement, FITs, and contracting, and the establishment of a "hybrid" market. This section discusses the context behind Ontario's restructuring decisions and how its current regulatory institutions developed. Figure 13 provides a timeline of key electricity restructuring events in Ontario.

Figure 13. Timeline of key events in Ontario



3.3.1 The decline of Ontario Hydro

For a period of time up until the end of the 1990s, Ontario Hydro essentially functioned as the province's monopoly supplier. Ontario Hydro controlled virtually all transmission, and on the generation side it produced over 90% of the province's electricity and controlled the balance of

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31 Revenue Cap IR is similar to Price Cap IR for distributors.

supply through non-utility generation contracts. On the distribution side, Ontario Hydro served around 1 million customers, although there were close to 300 municipal distribution utilities that served most customers.[32] However, in the 1990s, Ontario Hydro suffered major cost overruns, excessive debt, and poor nuclear performance.[33] As a result, electricity rates in the early 1990s rose by nearly 30%.[34]

Ontario first considered restructuring its electricity sector in 1996, when the so-called Macdonald Commission[35] issued its report called the "*Framework for Competition: The Report of Advisory Committee on Competition in Ontario's Electricity System to the Ontario Minister of Environment and Energy*." The report called for injecting competition into Ontario's electricity sector as soon as possible and suggested the possibility of breaking Ontario Hydro into a number of competing generation companies, some of which would remain publicly owned. The report noted that the creation of between five and six equally sized firms might be necessary to establish a workably competitive market.

3.3.2 Phasing in competition in the electricity market

It was not until the crisis in Ontario Hydro's nuclear operations in late 1997 and the subsequent loss of public confidence in Ontario Hydro that a consensus for reform became evident. Consequently, the Ontario Market Design Committee ("MDC") was set up in January 1998. The MDC was composed of key stakeholders from the Ontario electricity sector, and was tasked with developing an implementation plan consistent with the provincial government's White Paper on Electricity Restructuring titled, "*Directions for Change*." In this White Paper, the Government identified the two primary causes of Ontario Hydro's poor business performance. First, the problems associated with electricity monopolies which include higher prices, excessive debt, poor priority setting, and bureaucracy inefficiency.[36] Second, Ontario Hydro had an unclear relationship with the provincial government and had "a complex mandate as a commercial entity, an at-cost provider, and a regulator of other utilities."[37] The White Paper laid out the objectives of the restructuring plan which is shown in Figure 14.

Figure 14. Objectives of Ontario's restructuring plan

[32] Ontario Hydro. *Final Annual Report: January 1998 - March 1999*. June 23, 1999.

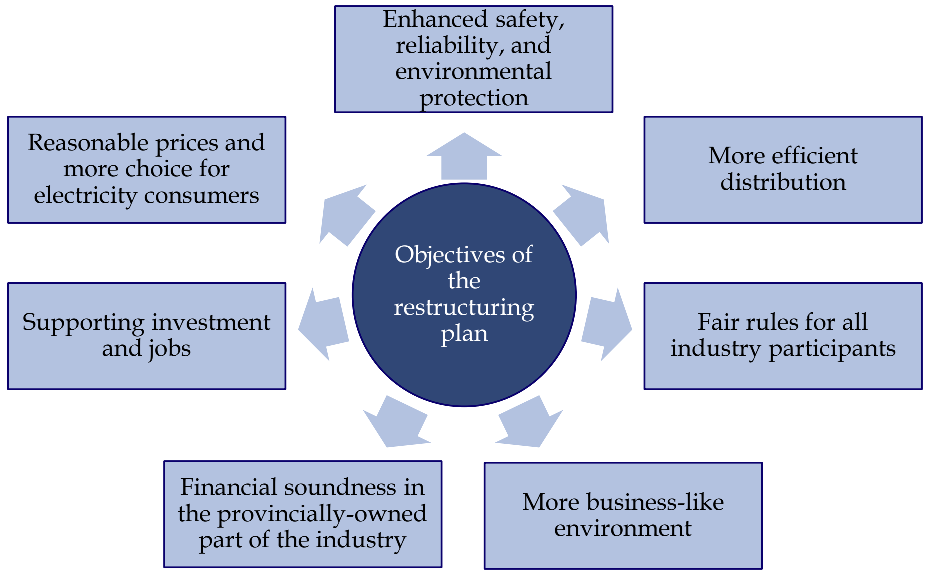
[33] Ontario Minister of Energy, Science and Technology. *Direction for change – Charting a Course for Competitive Electricity and Jobs in Ontario*. November 1997. P. 1.

[34] Ibid. P. 5.

[35] This Commission was formally called the Advisory Committee of Competition in Ontario's Electricity Sector.

[36] Ontario Minister of Energy, Science and Technology. *Direction for change – Charting a Course for Competitive Electricity and Jobs in Ontario*. November 1997. P. 7.

[37] Ibid. P. 8.



Source: Ministry of Energy, Science, and Technology ("Direction for Change – Charting a Course for Competitive Electricity and Jobs in Ontario")

As a result of the MDC's efforts, the *Energy Competition Act* of 1998 (also known as Bill 35) was passed, establishing the legislative framework for competitive electricity markets in the province. The MDC issued its final report in January 1999,[38] which finalized recommendations on market design, market rules, and transition issues and summed up its previous recommendations published in the Commission's three interim reports. Pursuant to the *Electricity Act* of 1998, Ontario Hydro was separated into the five companies, as shown in Figure 15.

The *Electricity Act* of 1998 also paved the way to codify the authority of the OEB to issue licenses to entities involved in the production, transmission, distribution, and sale of electricity. Moreover, under this Act, municipal utilities became business corporations with the municipality as the single shareholder initially. An Independent Electricity Market Operator ("IMO") was then established to run the market, with the Central Market Operations group of the former Ontario Hydro providing the nucleus for the new IMO.

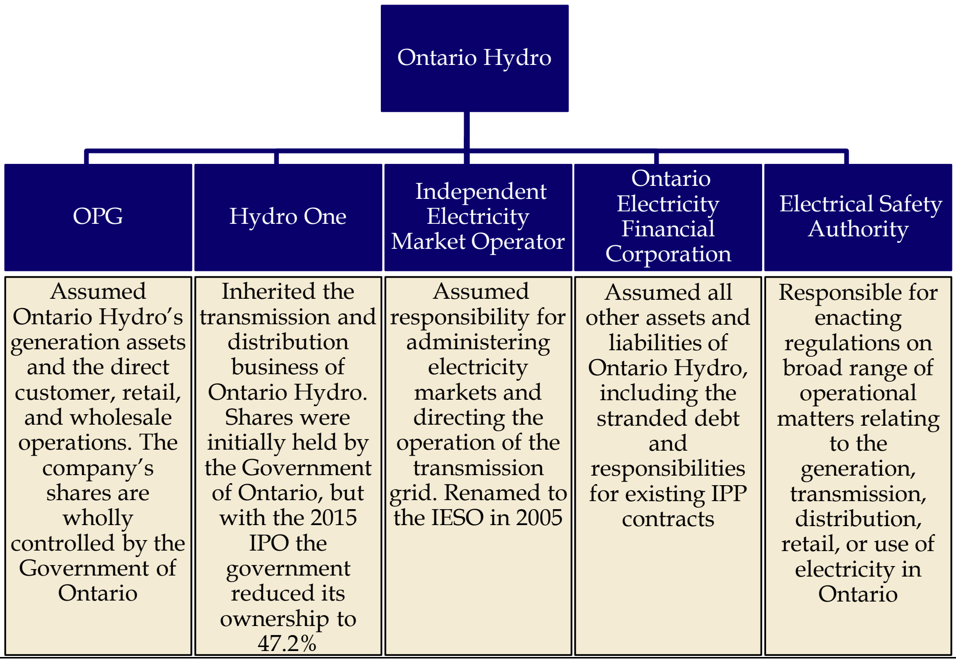
The *Electricity Competition Act* of 1998 also brought significant changes to the electricity distribution sector. The Government directed the OEB to "examine, advise on, and subsequently implement a performance-based ratemaking approach to regulation."[39] In addition, Ontario's municipal electric utilities ("MEUs") were required to incorporate under the Ontario Business Corporations Act ("OBCA") as LDCs and operate on a commercial basis. The OEB allowed LDCs to earn commercial returns, but required improved efficiency. Consequently, the LDCs have continued to consolidate over the past two decades. Just prior to restructuring, Ontario had close

[38] Ministry of Energy, Science, and Technology. *Final Report of the Market Design Committee to the Minister of Energy, Science and Technology*, Toronto, Ontario: Jan. 29, 1999.

[39] Ontario Minister of Energy, Science and Technology. *Direction for change – Charting a Course for Competitive Electricity and Jobs in Ontario*. November 1997.

to 300 municipal utilities, including many serving a very small number of customers. Consolidation has reduced this number to around 57 LDCs, although most remain quite small.

Figure 15. The deconstruction of Ontario Hydro on April 1, 1999



Another major development in the distribution sector was the adoption of an IR regime. In 2000, the OEB issued Decision RP-1999-0034, which approved an IR regime to regulate electricity distribution companies. The OEB believed that such regulation would offer two key advantages – first, it would provide companies with a strong incentive to continue and expand their efforts to control costs, increase efficiency, and maintain service quality. Second, it would minimize the administrative burden and the cost of regulation.[40] The first-generation incentive regulation mechanism was implemented on March 1st, 2001.

3.3.3 Stumbled roll-out of competitive markets

Ontario's competitive wholesale and retail sector was originally scheduled to open in November 2000. However, market opening was delayed first to May 2001 and later to May 2002 to ensure system reliability and to allow testing of the hardware and software acquired by wholesale market participants, service providers, and retailers. Following these delays, Ontario's competitive electricity market finally opened on May 1st, 2002, allowing generators to participate in competitive wholesale electricity markets. Soon after, during the summer of 2002, Ontario experienced extreme hot weather conditions coupled with tighter than anticipated supply conditions that led to price spikes in the wholesale market. The price spikes triggered a series of interventions by the Ontario government. On December 9th, 2002, the Ontario government passed the *Electricity Pricing, Conservation, and Supply Act*, 2002 (Bill 210), which froze commodity prices

[40] OEB. *Overview of the Electricity Distribution Rate Regulation Framework*. March 9, 2000. P. 2.

to end-users at 4.3 cents/kWh through 2006, and was applied retroactively to May 1st, 2002. Ontario's efforts at deregulation at the retail level were effectively unraveled with this price freeze.

Taken together, this still born roll-out of competitive markets combined with a lack of measures to prevent market domination by OPG impacted investor perceptions of the Ontario wholesale market. Unease surrounding the Ontario energy market as structured in turn led to a lack of new-build of generation by independent power producers.

3.3.4 Emergence of Ontario's hybrid market

In light of these events, on December 9th, 2004, the *Electricity Restructuring Act*, 2004 was passed. The purpose of this Act was not only to restructure the province's electricity sector, but also to promote the expansion of electricity supply and capacity, including supply and capacity from alternative and renewable energy sources; facilitate load management and demand management; encourage electricity conservation, and the efficient use of electricity; and regulate prices in parts of the electricity sector.[41] It also established the Ontario Power Authority ("OPA") to act as a creditworthy counterparty through which new generation could be procured by means of long-term PPAs. Through the creation of a centralized procurement agency, Ontario established what is now referred to as its "hybrid" market, which maintained the competitive energy market but provided independent power producers with contractual guarantees for revenue.

The OPA was initially set up to be a transitional organization, with the objective of smoothing the process of Ontario's move to a fully competitive market by using a temporary hybrid structure.[42] However, with Ontario's eyes turning towards green energy policies, it became clear that backing out of the hybrid structure would be a difficult task. Ontario's energy policy over this timeframe was largely guided by the *Green Energy and Green Economy Act*, 2009 ("GEA") and the Long-Term Energy Plan ("LTEP"), which offered direction for the development of clean energy. The GEA was enacted to promote renewable energy development in the province through the implementation of a Feed-in-Tariff ("FIT") program, which pushed for renewables by streamlining project development and by offering long-term contracts at above-market rates for renewable generation.

Other large-scale procurements of renewable resources were also launched by the government, notably procurement directives for large amounts of wind and solar, as well as large-scale procurement of natural gas resources (to replace coal which was pushed out due to decarbonization policies). This obligated the OPA (subsequently the IESO) to contract with qualifying projects, consistent with the procurement targets established by the government. Thus, it became clear that new and existing generation in the province would only participate under contractual agreements with a government-backed counterparty.

In 2015 the government pushed forward with an Initial Public Offering for Hydro One to raise capital, and a merger between the OPA and the IESO. As a result of the merger and other procurement initiatives by the government, by the second quarter of 2021 the IESO had 33,610

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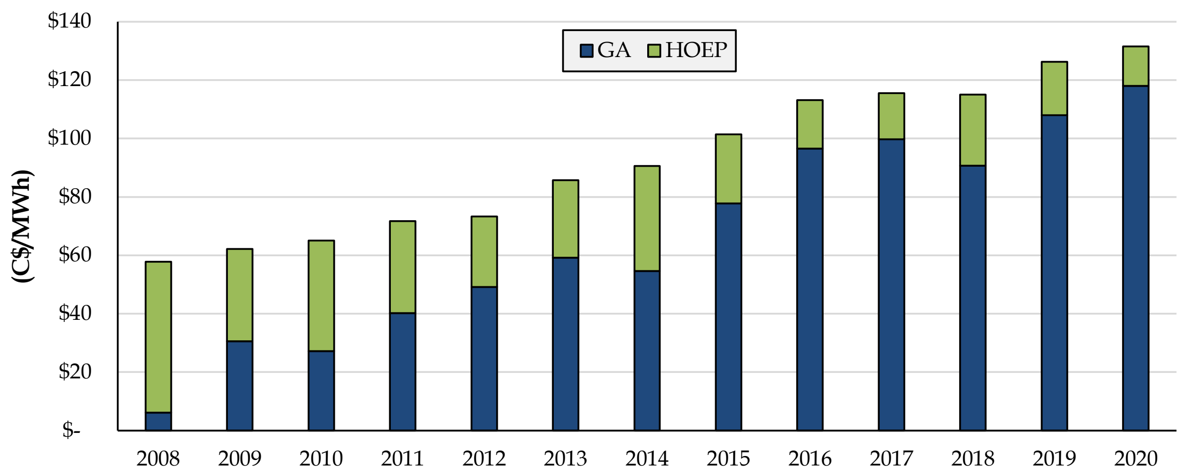
[41] Government of Ontario. *Electricity Restructuring Act 2004*.

[42] OPA Presentation from 2005. *Making Ontario's Electricity Market Work*.

electricity generation facilities under long-term contract, which totaled 26,727 MW of capacity (around 60% of Ontario's total capacity).[43] The province's remaining supply is made up of rate-regulated hydroelectric and nuclear resources owned by OPG. The number of participants continuing operations in Ontario's wholesale market without a contract are minimal, and IPPs do not make investments in new facilities with the expectation of earning money from wholesale markets alone (i.e., without a contract).

Because most larger contracts are structured as contracts for differences ("CfDs"),[44] contracted and regulated generators participate in Ontario's wholesale energy market, with the wholesale market price based on supply and demand, as balanced in real-time for each hour (referred to as the Hourly Ontario Energy Price or "HOEP"). Because of this, an additional component to the commodity cost of energy is required to recover the difference between the wholesale price of energy and the costs associated with these contracts, OPG's rate-regulated facilities, and other IESO administered programs (such as conservation and demand management initiatives). This additional component is referred to as the Global Adjustment ("GA"), which was established in 2005 with the creation of the OPA. Largely as a result of policy-induced procurements under long-term contract, and Ontario's hybrid market structure, the GA quickly rose to be the main component of Ontario's commodity costs, as can be seen in Figure 16. For reference, Figure 17 highlights the GA costs by component for 2020.[45]

Figure 16. Annual average commodity cost by component (Canadian $/MWh), 2008 – 2020



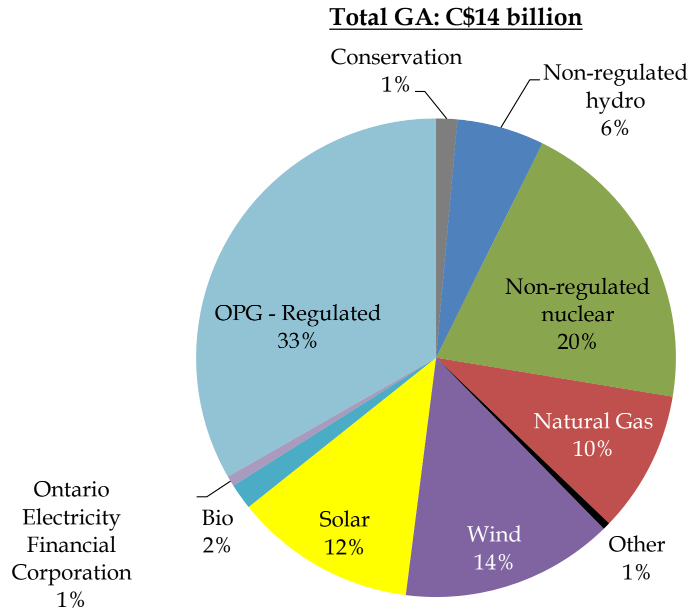
Sources IESO data on average HOEP plus GA.

Figure 17. GA composition by resource/contract type (2020)

[43] IESO. *A Progress Report on Contracted Electricity Supply: Second Quarter 2021*. June 2021.

[44] CfDs are contracts in which counterparties sell and buy at wholesale prices, but reimburse one another for deviations from a target strike price.

[45] When the HOEP increases, the GA falls, as market prices become closer to contract prices.



Source: IESO dataset. *GA by Component.* Accessed April 6, 2021.

As a result of the pressure caused by the growing costs of the GA, in November 2020 the Ontario government announced a measure to shift a portion of non-hydro renewable contract costs that were previously funded through the GA to the province.[46] This move would reduce the total pool of resources recovering their contracted revenues through the GA, but would not impact Ontario's hybrid market structure as it simply shifted recovery of around C$3 billion per year from the rate base to the tax base. Additionally, a large portion of the remaining GA pool is unlikely to change – revenues for regulated facilities will continue to be decided through the regulatory procedures and governmental structure, and nuclear facilities not under rate regulation will remain under lifetime contracts.

3.3.5 Potential changes going forward

In an attempt to improve Ontario's electricity market as structured, in early 2016 the IESO launched its Market Renewal stakeholder engagement process, with an overall objective of enabling "*a more efficient, stable marketplace with competitive and transparent mechanisms that meet system and participant needs at lowest cost.*"[47] Market renewal contained improvements to Ontario's energy market structure, by for example moving from the current system where prices and dispatch are determined through different unconstrained and constrained systems, to prices following the same constrained scheduling system as dispatch (leading to prices being determined on a locational basis). A main component of market renewal was the planned development of a competitive capacity auction to replace the current system of direct contracting

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[46] Ontario Ministry of Finance. *Ontario's Action Plan: Protect, Support, Recover.* November 2020. Queen's Printer for Ontario.

[47] IESO Presentation. Market Renewal Working Group. March 10, 2017.

for new resources as its main tool in securing Ontario's emerging capacity needs at competitive costs.

However, the IESO has since pivoted away from this stance, and on September 3rd, 2020, launched its Resource Adequacy Engagement to deal with Ontario's capacity needs currently expected to emerge in the mid- to late-2020s, formalizing the likelihood that centralized and direct procurement tools will continue to be used to meet Ontario's needs going forward. According to the IESO's most recent view, numerous acquisition mechanisms may be used to procure capacity. Capacity from new resources is most likely to be procured through a Request for Proposals ("RFP") process, or potentially through sole-source procurement; short-term needs may be met through a capacity auction, although this is envisioned to serve as a balancing mechanism to ensure resource adequacy.[48] With this procurement approach, it remains likely that Ontario's hybrid market structure will persist for the foreseeable future.

[48] IESO Presentation. *Resource Adequacy Engagemen*t. January 26, 2021.

4 New South Wales, Australia (full unbundling)

The New South Wales ("NSW") electricity market has completed its restructuring and deregulation efforts, and provides a useful example of full unbundling. In particular, NSW provides valuable lessons with regards to its gentrader model and vesting contracts, which address transitional challenges in privatization.

4.1 Overview of the New South Wales market

New South Wales is an Australian state bordering Queensland to the north, Victoria to the south, South Australia to the west, and the Tasman Sea to the east. It is Australia's most populous state with 8.2 million residents as of 2020. Its installed generation capacity is nearly 20 GW, with coal comprising more than 50% of the fuel mix (see Figure 18).

Among the state's five major generators, only one is still government-owned (Snowy Hydro), and all have retail operations – i.e., gentraders (see Section 4.3.2 for further details).[49] The majority of the network businesses are privatized: the transmission network in NSW is owned and operated by TransGrid,[50] which is privatized on a 99-year lease; the distribution utilities are owned by Ausgrid (fully privatized), Endeavour Energy (partially privatized – the NSW government retains 49% ownership), and Essential Energy[51] (government-owned). Vertical integration exists because there are ownership links between generators and retailers, however, operations are separated through "ring-fencing" agreements.[52]

The National Electricity Market ("NEM") is Australia's wholesale electricity market. The NEM operates an interconnected transmission network in eastern and southern Australia from Queensland to NSW, Victoria, South Australia, and Tasmania.[53] The NEM operates as an energy-only market in NSW, where generators sell electricity through a gross pool, spot market. Figure 19 shows the key players in NSW's electricity market.

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[49] AER. *State of the Energy Market 2013.* December 2013. P. 29.

[50] TransGrid. *New South Wales Transmission Annual Planning Report 2021.*

[51] Essential Energy. *Annual Report 2019-2020*; Australian Financial Review. *Critical post-mortem of $16.2b Ausgrid privatisation deal*. Dec 11, 2018; Australian Financial Review. *NSW sells Endeavour Energy stake to Macquarie Group-led consortium.* May 11, 2017

[52] AER. *State of the Energy Market 2021.*

[53] Ibid.

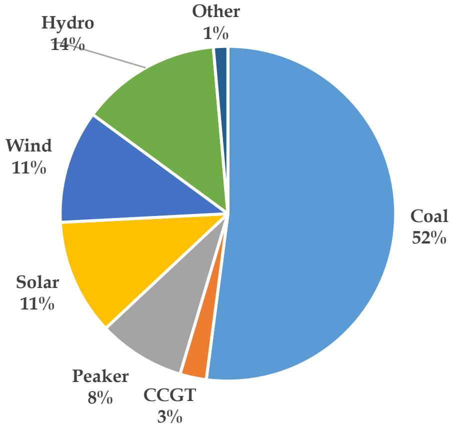
Figure 18. NSW market snapshot

New South Wales

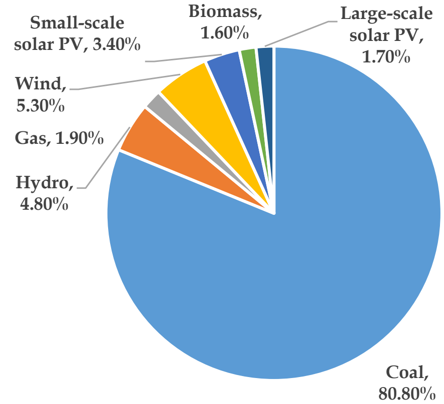
Key facts

Population (2020)	8.2 million
GDP growth (2019-2020)	-0.7%
Installed capacity (2021)	19,698 MW
Peak demand (2020)	13,835 MW
Load growth (CAGR: 2015-2020)	-0.6%
Generation (2020)	68.6 TWh
No. of electric distribution companies	3
No. of electric transmission companies	1

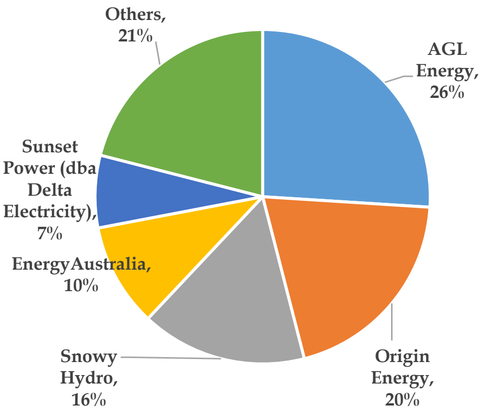
Installed capacity by fuel type (2020)



Generation by fuel type (2018)

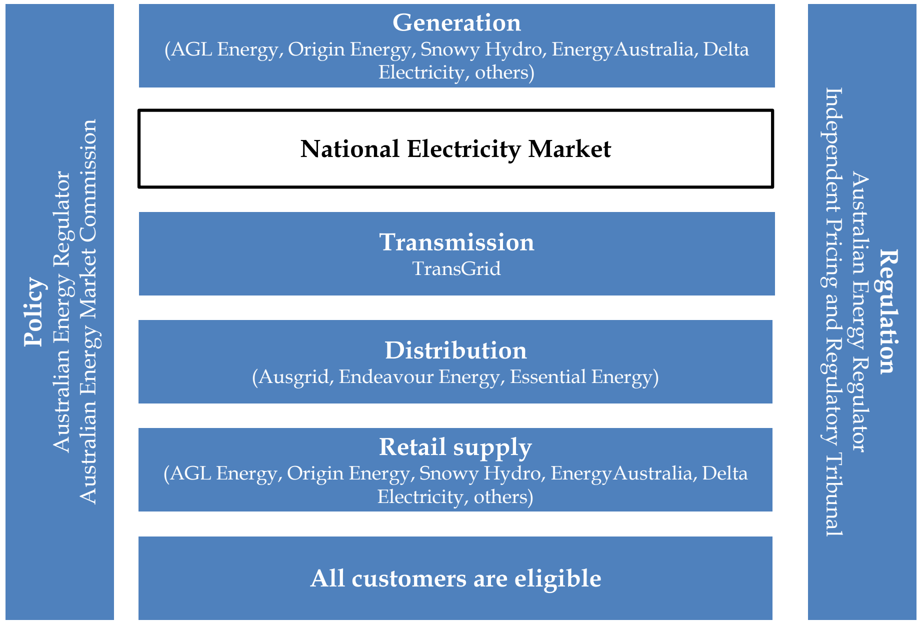


Major players by capacity (2020)



Source: Department of Planning, Industry and Environment, Australian Bureau of Statistics, Australian Energy Market Operator ("AEMO"), TransGrid.

Figure 19. Key market players in NSW's electricity value chain



Source: NSW Auditor-General; LEI research.

4.2 NSW's current institutional and legal framework

4.2.1 Regulation and policy setting

The National Electricity Law lays the foundation for the current regulatory regime governing electricity networks.[54] It aims to foster efficient investment and operation of the electricity market and is responsible for setting the ratemaking regime of regulated businesses in the network. The main industry regulators are the Australian Energy Regulator ("AER"), the Australian Energy Market Commission ("AEMC"), the Australian Competition and Consumer Commission ("ACCC"), the Australian Energy Market Operator ("AEMO"), and the Independent Pricing and Regulatory Tribunal ("IPART") – each of these entities is briefly described below:

- the **AER** is responsible for regulating and monitoring the wholesale market. It produces weekly reports on the spot and forward market in the NEM, and conducts investigations towards extreme price events if warranted. The AER also regulates the transmission and distribution networks by setting the maximum allowed revenue;[55]
- the **AEMC** conducts independent reviews of the electricity market and is accountable to the Council of Australian Governments;[56]

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[54] AER. *State of the Energy Market 2021*

[55] AER. *Our Role* <https://www.aer.gov.au/about-us/our-role>

[56] AEMC. *Our Forward Looking Work Program* <https://www.aemc.gov.au/our-work/our-forward-looking-work-program>

- the **ACCC** derives its regulatory power from the *Competition and Consumer Act 2010*. It promotes competition and consumer protection and fair trade, prevents anticompetitive conduct, and monitors the price in the energy markets;[57]
- the **AEMO** delivers planning advice and operates the energy markets and systems;[58] and
- the **IPART** is an independent pricing regulator of energy (chiefly focused on natural gas prices and monitoring electricity retail prices), water, local government, and transport. IPART also sets reliability standards for transmission and distribution services.[59]

4.2.2 Regulatory oversight of charges

Under the National Electricity Law ("NEL") and the National Electricity Rules ("NER"), the AER is responsible for the economic regulation of the electricity transmission and distribution services. On the other hand, IPART is responsible for regulating the prices for the retail sector.

Figure 20. Key PBR components for NSW utilities

PBR components for NSW utilities	
Form	Transmission networks are regulated under a revenue cap, while distribution networks are regulated under weighted average price caps
Approach	Building blocks approach
Going-in rates	Annual revenue requirements forecasted over the regulatory period on the basis of the building blocks approach
Term	5 years minimum
Inflation factor (I factor)	Quarterly CPI index
Productivity factor (X factor)	Specific for each year and utility. X factor is set to equalize (in present value terms) the revenue to be earned over the period to the total revenue requirements; X factor ranges between -13.3% to 0% depending on the distribution utility
Capital expenditure	Ex ante capex allowances are included in the building blocks approach through annual forecasts of rate base
Service quality (Q factor)	Capped rewards/penalties for specific performance targets. Targets set on the basis of a firm's historical performance . Not yet uniformly applied to all networks
Efficiency carry-over mechanism ("ECM")	Symmetric ECM with 30% of efficiency gains/losses retained by utility. Carry over mechanism (covers 6 yrs.). Currently applies to opex
Exogenous factors (Z factor)	Applies to specific events such as regulatory or tax change, disaster or terrorist event. General cost pass-throughs for costs beyond control of network that exceed minimum value
Off-ramps	Only for transmission utilities. Re-opener is available for events significantly altering the allowed level of capital expenditure

Source: AER.

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57 ACCC. *About Us* <https://www.accc.gov.au/about-us/australian-competition-consumer-commission>

58 AEMO. *Who We Are* <https://aemo.com.au/about/who-we-are>

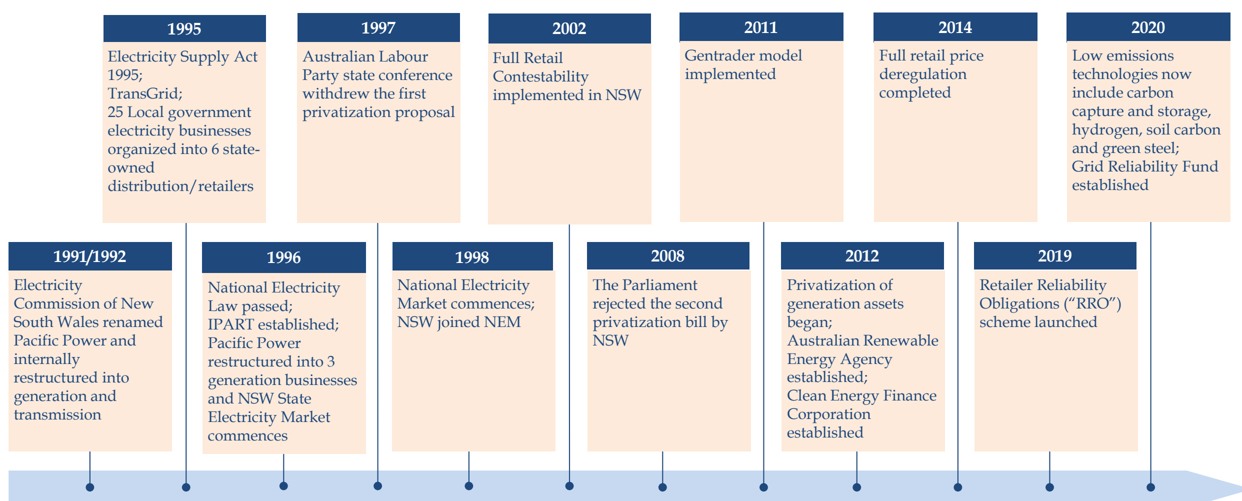
59 IPART <https://www.ipart.nsw.gov.au/Home/Industries/Energy/Energy-Networks-Safety-Reliability-and-Compliance>

NSW uses a building blocks approach to price regulation for the transmission and distribution sectors.[60] In this sense, the regulator determines efficient cost components and uses these costs to determine a maximum revenue requirement. The transmission networks are regulated under a revenue cap, while distribution networks are regulated under weighted average price caps. NSW's performance-based ratemaking ("PBR") regime includes service quality standards with rewards and penalties, ex ante capex allowances, and a symmetric efficiency carryover mechanism with 30% of efficiency gains or losses retained by the utility. Figure 20 provides a summary of the key components of NSW's PBR mechanism.

4.3 History of restructuring

Electricity market restructuring in NSW was driven by inefficient investment and poor operational performance by state-owned generators. Early developments in the 1990s included establishing the state internal pool market, and the restructuring of the generation, transmission, and distribution businesses; privatization and deregulation efforts subsequently faced transitional challenges. Full retail price deregulation was completed in 2014 and the privatization of generation assets was completed by 2015. Figure 21 provides a timeline of key restructuring events in NSW.

Figure 21. Timeline of key electricity restructuring events in NSW



Source: AER and LEI research

Notably, NSW is a pioneer in electricity restructuring in Australia. The restructuring from 1991 to 1996 involved establishment of three generation businesses, separation of the transmission assets into TransGrid, and consolidation of a fragmented distribution sector into six distribution businesses.

[60] Ibid. P. 129.

Prior to the commencement of the NEM in 1998, NSW established the Pacific Power Internal Pool Market ("ELEX"), which was modeled after the first UK pool market in 1991/1992.[61] In 1998, NSW joined the NEM and operated in an interconnected network.[62] Figure 22 below presents the key design elements of NSW's market restructuring and development efforts, which are discussed in detail in the subsections that follow.

Figure 22. Summary of specific design elements

Design elements	Rationale	Pros	Cons
Privatization of generation assets	To build a fully competitive market	• Improve productivity and foster efficient capital investment in sector • Generate additional revenue for the government to pay back its debt and to fund the public infrastructure • Save money on future electricity costs	• Short-term plan to fund public infrastructure
Gentrader model	To provide as an alternative to privatization	• Mitigate the government's risk in electricity trading	• Risks of additional costs borne by the generation owner
Retail deregulation	To foster retail competition	• Foster retail competition and lower the electricity price for small consumers because they can choose electricity products and retailers • Retailers earn profit margin comparable to a competitive market • Customers are generally satisfied with the retail service	• More transparency and information are needed for retail choice • More clarification on retail choice and time-of-use tariffs are needed
PBR	To facilitate an incentive based ratemaking, which will allow the accommodation of higher-powered incentives when needed	• Able to accommodate higher-powered incentives	• Add significant administrative costs as an information-intensive approach • A Total Productivity Factor ("TPF") approach provides more powerful incentives to improve efficiency in the network by reducing capital and operating expenditure and regulatory costs

4.3.1 Initial attempts to privatize generation assets

Although privatization is not a prerequisite for electricity restructuring, the government of NSW viewed it as a critical component of a fully competitive electricity market and made consistent efforts to privatize the sector. Private ownership is viewed as a way to improve productivity and foster efficient capital investment.

The NSW Treasury initially advocated for privatizing the sector, claiming that it would generate additional revenue for the government, save money on future electricity costs, allow the government to pay back its debt, and finance public infrastructure such as transport, schools, and

[61] Ibid. P. vi.

[62] Ibid.

hospitals.[63] However, the Electrical Trades Union in NSW argued that public ownership would provide a stable revenue stream to fund public infrastructure.[64] This raised the question of whether the current and future benefits of privatization—including lump sum payments upfront and a tax revenue stream in the future—outweigh future benefits of continued ownership. Opponents also argued (fallaciously) that the privatization would lead to higher electricity prices, stating that asset sales were a short-term, ill-conceived plan to fund the state infrastructure.

There were two attempts to privatize the industry before 2011, but both failed to secure political support from the state. The first attempt was in 1997 when the Treasurer Hon. Michael Egan proposed to privatize the generation, distribution, and retail sector, which was expected to raise $22 billion for the government.[65] However, the proposal was withdrawn by the Australian Labor Party ("ALP") State Conference.[66] The second attempt in 2008 failed when parliament rejected the Bill introduced by the NSW Government to lease generation capacity, privatize generators via Initial Public Offerings, and privatize the retail business.[67] The main opponents of the Bill were ALP parliamentary representatives led by the ALP State President Bernie Riordan.[68] The move toward privatization caused conflict between labor and trade union groups and NSW Premier Morris Iemma – who endorsed the move – causing further aggravation in the looming conflict over jobs and wages.[69]

Faced with difficulty gaining political support for privatization, the NSW government embarked on a scheme designed to introduce competition in the state-owned generation sector.

4.3.2 Gentrader model

The several unsuccessful attempts to privatize the generation assets in NSW drove the government to adopt a gentrader model in 2011. The intent was to introduce competition in the wholesale market and reduce potential risks. Under a gentrader model, the government of NSW retained the ownership of and responsibility for the day-to-day operations of generation assets, while gentraders retained the right to trade electricity. Under this model, the gentraders paid the Government two fees: (i) capacity charges to the state-owned generators over the life of the contract for having access to the capacity of the generation asset; and (ii) monthly fixed and variable costs such as maintenance, fuel, wages, capital operating expenditure, and any carbon liability that may have emerged as a result of the introduction of a carbon tax or similar

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[63] "NSW Government to privatise electricity generators." *ABC News*. 15 November 2012. Available at <http://www.abc.net.au/news/2012-11-15/nsw-government-to-privatise-electricity-generators/4372858>

[64] "Unions attack Labor over call for electricity sell-off." *The Australian*. 13, August 2012. Available at <http://www.theaustralian.com.au/national-affairs/unions-attack-labor-over-call-for-electricity-sell-off/story-fn59niix-1226448735324#>

[65] Ibid. P. 37.

[66] Ibid. P. 37.

[67] Ibid. P. vii.

[68] "NSW Labor to fight Iemma on privatization." *Crikey*. Web. 18 February 2008. Available at <http://www.crikey.com.au/2008/02/18/nsw-labor-to-fight-iemma-on-privatisation/?wpmp_switcher=mobile>

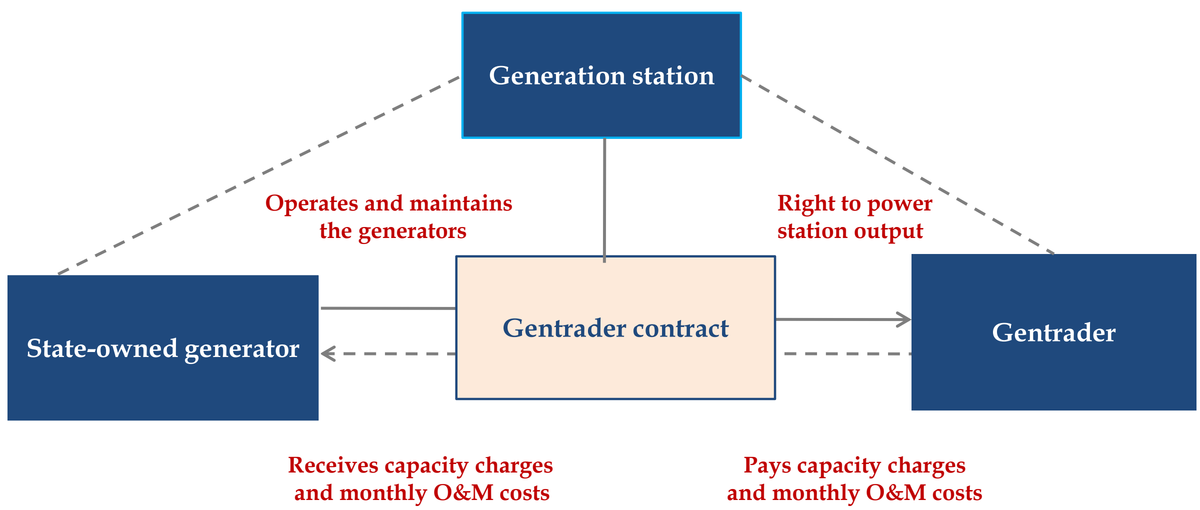
[69] Ibid.

arrangement.[70] The state-owned generators remained as the contract counterparties to existing fuel contracts and passed the contract costs on to the gentraders.

The gentrader model was advantageous because it allowed the government to get "*out of the risky business of electricity generation and electricity trading*."[71] The usual role of the state-owned generator shifts towards ensuring that the asset is maintained in good condition and capable of meeting the requirements of the gentrader contracts. This means that the state's generating companies function as asset managers, while the energy market and trading risks are borne by gentraders.

Although gentraders pay monthly fixed fees (with some escalators built into the fees) over the life of the contract, there is still the risk that additional costs must be borne by the generation owner. During a stakeholder consultation, critics raised the issue that "*the gentrader model exposes the generator state-owned corporations to on-going financial risks with respect to the operational performance of the generators while eliminating their ability to manage those risks through control over operational and maintenance strategies*."[72] Nevertheless, the government determined that dealing with the risks being faced by the state under the energy reform transactions and the gentrader model were better than maintaining the status quo.[73]

Figure 23. Gentrader model



Source: LEI based on the description in the Legislative Council

Each gentrader was allotted a set maximum available capacity, which the generator could dispatch into the NEM at any time on its behalf. A generator paid a penalty called availability liquidated damages ("ALDs") to the gentrader if it was unable to deliver power when scheduled

[70] Legislative Council. *The Gentrader Transactions. Standing* Order 231. February 23, 2011. P. 19.

[71] Ibid. P. 21.

[72] Ibid.

[73] Ibid.

to do so and called upon. The ALD cap, set on a yearly basis, was equal to the capacity charge paid by the gentrader.

4.3.3 Privatization of generation assets

In 2012, the state passed the *Electricity Generator Assets Act 2012* to facilitate the sale of the generation assets to gentraders.[74] Origin Energy acquired the Eraring and Shoalhaven power plants, which were previously under a gentrader agreement.[75] EnergyAustralia acquired the Mount Piper and Wallerawang power stations in September 2013, paving the way for further privatization.[76] Macquarie Generation was later privatized and sold to AGL Energy in 2014,[77] and Delta Electricity also sold to Sunset Power in 2015.[78]

Following the privatizations of the generating assets by the NSW government, the contractual obligations under the gentrader model have since expired.

4.3.4 Retail deregulation

NSW was the first to implement full retail contestability ("FRC") in Australia. Since January 1st, 2002, all electricity customers in NSW have had the option to choose their retail electricity supplier or to remain with the Standard Retailer on a regulated tariff.[79] However, regulations still existed for network service charges of electricity distribution businesses as they remained monopoly businesses.

Increased network costs and climate change policies have led to a significant increase in retail electricity prices in NSW. With the privatization of retail businesses, more retailers were entering the market and customers were increasingly shifting their retailers to respond to the rising electricity price. Hence, retail price regulation impeded the competition in the retail sector. To foster innovation and competitive pricing, the AEMC put a package of recommendations forward including retail price deregulation, information sharing, consumer protection, and market monitoring.

The retail deregulation is generally considered a success, subject to the following observations:[80]

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74 Ibid.

75 Ibid.

76 "Mt Piper & Wallerawang Power Stations Project." *EnergyAustralia.* 2012. Available at <http://www.energyaustralia.com.au/about-us/what-we-do/projects/mt-piper-and-wallerawan>

77 AGL Energy. *AGL completes sale of Macquarie Generation and announces leadership change.* Sep 3, 2014 <https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2014/september/agl-completes-sale-of-macquarie-generation-and-announces-leadership-change>

78 Australian Financial Review. *NSW government sells Vales Point power station for $1m.* Nov 19, 2015 <https://www.afr.com/companies/mining/nsw-govt-sells-vales-point-power-station-for-1m-20151119-gl2uxn>

79 IPART. *Recovery of Full Retail Contestability Costs By New South Wales Energy Businesses.* August 2001. P. 5.

80 Ibid. P. v.

- deregulation fosters retail competition and lowers electricity prices for small consumers because they can choose electricity products and retailers;
- there are few barriers to entry for retailers. Small retailers are competing with large players. Origin Energy and EnergyAustralia lost significant market share when customers shifted to small retailers;[81]
- the retailers achieve profit margin comparable to a competitive market;
- consumers are generally satisfied with the retail service, but they demand more transparency and information to make retail choice; and
- the Standing Council on Energy and Resources is developing policies to clarify retail choice and encourage deeper understanding of the time-of-use tariffs offered by all retailers.

4.3.5 Performance-based ratemaking

The National Electricity Rule outlines objectives and principles upon which distribution regulation is administered. It requires, among others, the following outcomes:[82]

- an efficient and cost-effective regulatory environment;
- an incentive-based regulatory regime which provides equitable allocation of savings, a sustainable commercial revenue stream which includes a fair and reasonable rate of return, and consistency in the regulation of connection and distribution service pricing;
- an environment which fosters an efficient level of investment, operating and maintenance practices, and use of existing infrastructure; and
- regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions, and reasonable certainty and consistency over time of the outcome of regulatory processes.

From the very beginning of Australia's incentive-based regulation in the late 1990s, there have been continuous arguments on whether the regulator should adopt the current building block approach or the Total Factor Productivity ("TFP") approach (these two approaches are defined in the textbox on the following page). Advocates of the current regime endorsed the building block approach because of its ability to accommodate higher-powered incentives. Moreover, the building block approach in NSW allows for the implementation of a clearly defined planning process for network investment and revenue certainty. Utilities are also certain that their capex plans will be reflected in the rates.

The building block approach is an information-intensive approach, which heavily relies on forecasts and extensive benchmarking analysis in setting the efficient cost. It can burden regulators with additional administrative costs, particularly in gathering adequate information from the utilities as they try to determine the appropriate revenue requirements. Furthermore,

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[81] AEMC. *Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales.* October 2013. P. v.

[82] AER. Gas and Electricity Distribution Regulatory Guidelines. March 2006.

there were concerns that prices were increasing because of higher reliability standards and favorable appeal regime for utilities. Therefore, some experts endorsed a TFP approach that creates more powerful incentives to improve productivity by reducing capital and operating expenditure and regulatory costs. The AEMC reviewed the TFP approach in its price regulation in 2011 and found that it will improve efficiency in the networks.[83] However, the building block approach still remains as the means to determine the revenue cap for network companies in NSW.

Performance-based ratemaking: the building block approach versus the TFP approach

There are generally two approaches for rate-setting under a PBR regime: (i) **the building block approach**, and (ii) **a TFP approach**.

The building block approach sets a utility's revenue requirement amounts for each year of the regulatory term to determine the ultimate rate to be charged to customers. The name 'building block' comes from the approach taken to calculate the required revenue amount. To "build up" the revenue requirement, a forecast of total costs is prepared (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each "block" of the revenue requirement for each year. The forecast accounts for productivity improvements and targets and necessary capital investment.

In contrast, the TFP approach was developed as a relatively simple mechanistic, yet empirically "rich" approach to adjusting rate caps and providing incentives. The basic view that grounds most TFP-based applications of PBR models is that utilities should be able to improve productivity consistent with measured long-term productivity improvements (historically) for the industry as a whole; the historical productivity trend is generally determined through the statistical study of a group of comparators.

4.3.6 Mechanisms to transition to the NEM

Prior to the commencement of the NEM in 1998, the NSW established a state pool market modeled after UK's gross pool model of 1990s. The introduction of the pool market improved the financial performance of the sector and optimized the utilization of the capacity. Although Pacific Power continued to supply energy under a uniform bulk supply tariff ("BST"), it declined due to the efficiency gains brought by the pool market. The reduction in BST decreased the cross subsidies (in retail tariffs) for small and medium business. The success of the state pool market had a significant influence on the introduction of the NEM, which adopted a similar pool model.

To address the transitional challenges brought by the NEM, NSW employed several specific designs, which include vesting contracts and transitional default tariffs.

The ***vesting contracts*** were structured as two-way hedges between the generators and retailers. The volumes were matched to the energy supplied to non-contestable customers and gradually reduced as the number of non-contestable customers fell. The form of the contract (a two-way

[83] AEMC. *Review into the Use of Total Factor Productivity for the Determination of Prices and Revenues.* July 2011. P. i.

hedge) meant that retailers were not exposed to any wholesale price risk for energy supplied under these contracts. The contract price was set based on pre-existing regulated retail tariff to manage the transition of retail prices.

Under the ***transitional default tariffs***, all customers had the right to remain on their previous regulated tariff for the first 12 months after choosing their retailers. The government provided greater protection for small customers (mostly residential customers). It required IPART to set a standard tariff at which the default supplier[84] must continue to offer supply to small customers indefinitely. The default supplier can offer service at other unregulated tariffs but they must also offer the standard tariffs for small customers.

[84] For example, the retailer/distributor who supplied the area in which the customer is located prior to the introduction of competition.

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