12-2020

The convergence of water, electricity and gas industries: Implications for PPP design and regulation

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September 2020

Competition and Regulation in Network Industries (forthcoming)

Abstract : In several countries that have privatised their utilities, power and water are separate industries regulated by sector-specific regulators. In a parallel development, desalination has become an important source of water supply in countries where there is a shortage of cheap and clean freshwater. Where the energy source is gas, the use of gas-fired power plants to supply electricity for desalination links the water, electricity and gas industries. We use the case of the financial collapse of an integrated water and power project to illustrate the problems that can arise from such convergence, and to draw lessons for firms, Public-Private Partnerships (PPPs) and regulators. A water company had successfully tendered to build a desalination plant for a water agency that would deliver an agreed volume of water per day for a 25-year period. The technology proposed was an integrated on-site power plant to supply electricity to the desalination plant as well as to the electricity grid. The business model was for profits from electricity sales to cross-subsidise water desalination costs. However, a combination of take-or-pay LNG contracts and low spot prices in a competitive electricity market led to deep operating losses. The reasons for the collapse of the business were neither technological nor operational but arose from failure to adequately manage the market risks arising from infrastructure convergence, competition, long-term rigid contractual arrangements and missing markets. The case highlights the importance of risk assessment at bidding stage and, in particular, the risks that a cross-subsidy can create. Viewed in this context, our recommendations are for regulatory convergence for converging infrastructure sectors, multi-sector risk assessments for PPP contracts, crafting flexible PPP contracts in anticipation of future adjustments, development of more liquid hedging markets and promoting competition where feasible in infrastructure sectors.

Keywords: Infrastructure convergence, market risks, missing markets, infrastructure regulation, electricity sector liberalization, public-private partnerships

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* An earlier draft of this paper was presented at the "9th Conference on the Regulation of Infrastructures: Sector Coupling. How to regulate convergence?" organised by the Florence School of Regulation, European University Institute, held virtually on 24-26 June 2020. I am deeply grateful to Ilaria Conti, Stéphane Saussier and two anonymous reviewers for valuable comments and suggestions.

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Introduction

In several countries that have privatised their utilities sectors, the power and water industries have developed separately and are regulated by sector-specific regulators. In the United Kingdom (the pioneer of privatisation and regulation of privatised infrastructure), when the gas and electricity supply industries were privatised in 1986 and 1989 respectively, the Office of Gas Supply (Ofgas) and the Office of Electricity Regulation (OFFER) were created as the respective sectoral regulatory agencies. In 2000, the two regulators were merged to form the Office of Gas and Electricity Markets (Ofgem). The Office of Water Services (Ofwat) was established in 1989 when the water and sewerage industry in England and Wales was privatised. Most countries that privatised their utilities also followed the UK's institutional setup of having sectoral regulators.[1]

In a parallel development, in an increasing number of jurisdictions where there is a shortage of cheap and clean freshwater, desalination of seawater is the main or a supplementary source of water supply.[2] Desalination uses two primary technologies: thermal distillation or membrane technology also called seawater reverse osmosis (Darre and Toor, 2018). Both methods are power intensive with energy cost being the highest contributor to operating cost and thus to the overall costs. As reliability of electricity may also be a problem, an on-site power plant that supplies electricity to the desalination plant is a form of sectoral integration that can enhance operational efficiency (Reimers and Webber, 2018).

In the past decade, there has been a dramatic decrease in the cost of desalinated water due to developments in membrane technology, transition to larger capacity plants, co-location

[1] There are strengths and weakness of a general multiple sector versus individual sector regulators. See Consumer Affairs Victoria (2006), Schwartz and Satola (2000).

[2] According to the International Desalination Association, there were about 16,000 desalination plants worldwide in 2019 that together supplied water for nearly 5% of the world's population in Europe, Africa, Australia, the Americas, the Middle-East and the Far East (Voutchkov et al. 2019).

with power plant generation facilities, and increased competition from the use of concession bidding. Developments in nuclear and renewable energy technologies (solar, geothermal, wind and water) have also contributed to reducing the cost of desalination (Deniz 2015; Esmaeilion 2020). In countries where the primary energy source is natural gas, the use of combined cycle gas turbine (CCGT) power plants to supply electricity for desalination links the water, the electricity and the gas industries (Darwish et al., 2015; Reimers and Webber, 2018).

In this paper, we use a case study to illustrate how PPPs involving several regulated and non-regulated activities within a unique contract can generate specific issues. In particular, we analyse the cross-sectoral challenges posed by the water, electricity and gas nexus for firms, PPPs and regulators. The next section describes the regulatory frameworks for water and power in Singapore. We then analyse the cause of the financial woes faced by an integrated water and power project in Singapore. We then develop a hypothetical scenario to illustrate the risks and problems that can arise in infrastructure sectors that are linked and yet operate under different sets of regulations and constraints. Finally, we conclude with recommendations for firms, PPPs and regulators of converging utility industries.

The regulatory frameworks for electricity, gas and water in Singapore

Singapore is a small island city-state with a land area of 720 square kilometres and a population of 5.7 million. It was a former British colony which became self-governing in 1959, joined the Malaysian Federation in 1963, and became an independent Republic in 1965. Until the 1990s, utilities in Singapore were vertically integrated monopolies owned and operated by the public sector. In the 1990s, following the wave of privatisation in the U.K. under the Thatcher government, the Singapore government took steps to implement its version of privatization. Temasek Holdings, a government owned investment holding company (often described by observers as a sovereign wealth fund), wholly or partly owns several companies that were

previously state-owned entities, some of which were subsequently partially listed on the Singapore stock exchange. The telecommunications sector was the first infrastructure sector to be partially privatised through a public listing in 1993. In this section, we describe the phased privatisation and liberalisation of the electricity and gas sectors, as well as PPP projects in the water sector.

Electricity

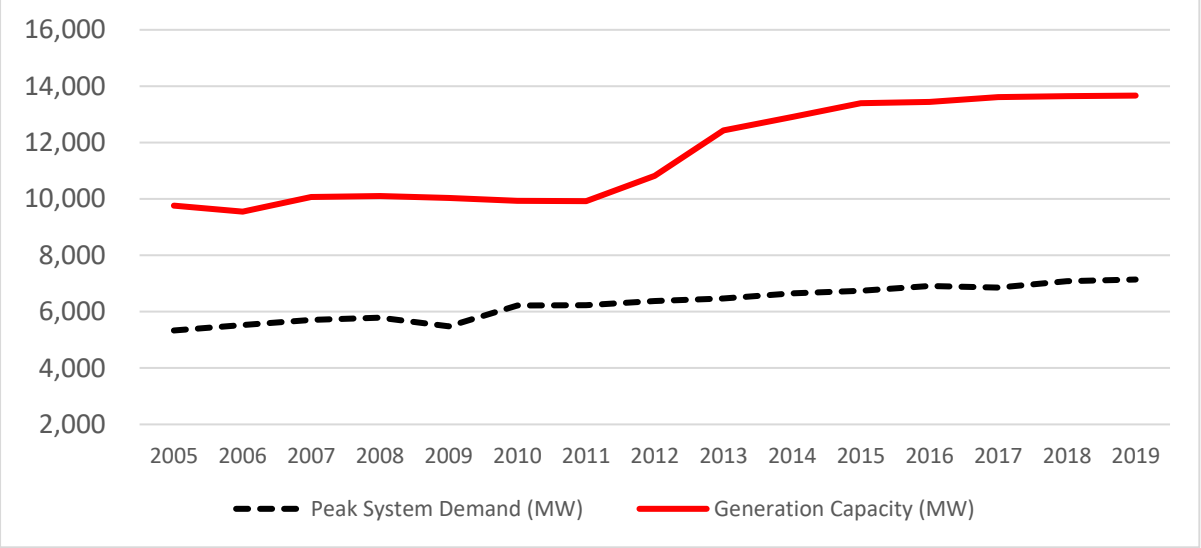
The energy sector in Singapore has gone through a careful and long journey of liberalisation (Koh and Lee, 2011). In 1995, the electricity and piped gas undertakings of the Public Utilities Board (PUB) were corporatised to form Singapore Power Ltd as a utilities holding company fully owned by Temasek Holdings. The process separated the grid from generation, creating an electricity transmission and distribution company, PowerGrid, three electricity generation companies, a retail services subsidiary, Power Supply Ltd, and a gas subsidiary, PowerGas Ltd. During this transition phase, the PUB took on the task of regulating the electricity and gas sectors.

In 2001, legislation was passed to establish the Energy Market Authority (EMA) as the industry regulator with the mandate "to ensure a reliable and secure energy supply, promote effective competition in the energy market and develop a dynamic energy sector in Singapore".[3] The EMA established the Energy Market Company (EMC) in 2002 to operate the wholesale market systems. The average monthly Uniform Singapore Energy Price (USEP) is derived from half hourly USEP prices from wholesale electricity market interactions. The EMC is currently a subsidiary of the Singapore Exchange and is regulated by the EMA.

[3] At the same time, Singapore Power Limited's electricity generation business was divested to level the playing field in the electricity industry. Ownership of the generation companies divested by Singapore Power were transferred to its parent company, Temasek Holdings. Source: https://www.ema.gov.sg/Milestones.aspx

It was only in 2008 (13 years after they were corporatized) that the three power generation companies (Gencos) owned by Temasek Holdings were divested through a direct sales tender process. Tuas Power was sold for S$4.2 billion to China Huaneng Group; Senoko Power was sold for S$3.6 billion to a Japanese/French consortium; and PowerSeraya for S$3.8 billion to YTL Power, a Malaysian power company.[4] There are currently 15 generation companies (Gencos) of 10 MW or more capacity that need to bid in the wholesale market to secure dispatch, and 35 smaller licensed generating units of between 1 and 10 MW which are connected to the grid. The total registered generation capacity at the end of 2019 was 12,451 MW while peak system demand was 7,200 MW (see Figure 1).[5]

Figure 1 Generation Capacity and Peak System Demand (MW)



Source: Data from website of Energy Market Authority, Singapore

To mitigate the potential misuse of market power by the three dominant Gencos, EMA introduced vesting contracts as a regulatory instrument in 2004. These contracts (between

[4] The exchange rate in September 2020 is approximately US$1 to S$0.73.

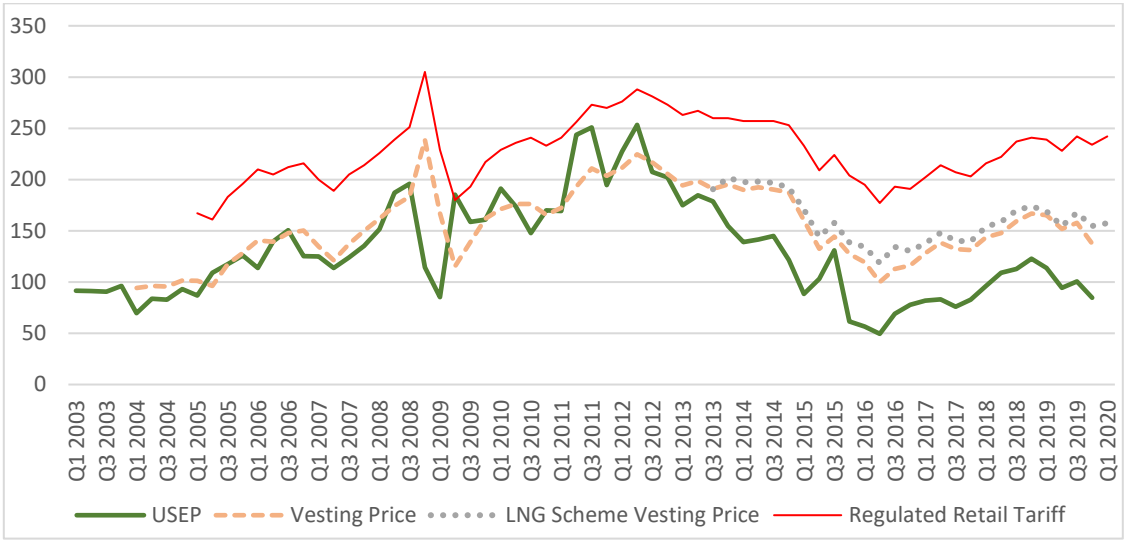
[5] For details of market processes used to determine half-hourly prices and dispatch, see Energy Market Company (2020).

Gencos and SP Services) paid a vesting price for part of the electricity demand (the vesting contract level) regardless of the market price.[6] This promotes competition as Gencos do not have incentives to withhold generation capacity to sustain inefficient spot prices in the wholesale electricity market. The vesting price is determined by approximating the long run marginal cost (LRMC) of a theoretical new entrant using the most efficient new generation technology in Singapore that contributes to more than 25% of demand (currently the F class CCGT, a gas turbine power plant); the price is recalculated every quarter, and vesting parameters are reviewed every two years or when necessary (Energy Market Authority, 2018b). With more Gencos entering the market over the years, the regular vesting contract level was reduced gradually - from 65% of total demand in 2004 to 20% by June 2019. Thereafter, only LNG vesting contracts (see the section on Natural Gas below) remain until June 2023. An electricity futures market was launched in 2015 to allow for more efficient hedging.

EMA regulates the electricity tariff charged by SP Group and these are reviewed every quarter to reflect costs (see Figure 2). The tariff comprises two main components – fuel cost and non-fuel cost. The fuel cost is tied to the prices of imported natural gas which in turn is indexed to oil prices by commercial contracts (the market practice in East and Southeast Asia). The fuel cost component for each quarter is calculated using the average of daily natural gas prices in the first two-and-a-half month period in the preceding quarter. The non-fuel cost component includes power generation cost, network cost, market support services fee, as well as power system operation cost and the cost of administering the wholesale electricity market. The regulated tariff for April to June 2020 was S$0.2463 per kWh for households.

[6] The contracts are two-way swap contracts written against the half-hourly USEP with hedge quantities and price referred to as the vesting contract level and vesting price, respectively. SP Services is the counterparty to these bilateral hedging contracts and it allocates the net benefits or costs of the vesting contracts to the retailers and consumers who purchase electricity from the pool (Energy Market Authority, 2018a).

Figure 2 Average Quarterly Uniform Singapore Energy Price (USEP), Quarterly Vesting Prices and Regulated Retail Tariff (S$/MWH)



Sources: Data from websites of Energy Market Authority and Energy Market Company, Singapore

EMA also adopted a phased approach to liberalize the retail market. Starting from 2001, very large consumers (whose demand is above 2MW) could begin to buy electricity from a retailer of their choice which in the few cases meant directly from the retail arm of Gencos. The consumption threshold for a consumer to become eligible to choose a retailer was reduced gradually over the next 17 years, leading to more retailers entering the market so that by 2019, all households and small businesses were finally allowed to buy electricity from a retailer of their choice. With retail market liberalisation, there are currently more than 20 electricity retailers who compete for customers with different types of price plans.

Natural Gas

EMA is *also* the regulator for the gas industry and markets in Singapore. A small island city-state, Singapore has no indigenous hydrocarbon reserves and imports all its crude oil and natural gas. Up until the late 1990s, oil was the primary source of fuel for electricity generation. After the liberalization of the electricity market and following trends in other jurisdictions,

competition in the generation industry translated into a "flight to gas" as more efficient gas turbines replaced oil-fired generators. Currently, more than 95% of Singapore's electricity is produced from natural gas, up from 26% in 2001. Gas market reform beginning with the Gas Act of 2001 was modelled on legislation and gas network codes from other liberalised gas markets and supported the parallel liberalization of the electricity market. The Gas Act separated the natural monopoly part of the industry from the segments where competition would be feasible. It established an independent gas transporter and a gas network code to govern the relationship between the transporter, the importers, shippers, retailers, and (from 2007) Liquefied Natural Gas (LNG) terminal operators.

Until 2013, all natural gas was imported from Malaysia and Indonesia through four pipelines. Piped Natural Gas (PNG) is purchased on long-term contracts with dates of expiry between 2018 and 2029. To diversify its fuel import sources for greater security of supply, the government began development of Singapore's first LNG terminal in 2010 at a cost of S$1.7 billion. The terminal began operations in 2013. The decision to invest in LNG was made for strategic rather than economic reasons as high investment costs are incurred for LNG production, transport and regasification facilities and LNG prices then were higher than PNG prices. The bulk of Asia's LNG is still sold on take-or-pay contracts for a long period, generally 20 to 25 years during which there are strictly defined obligations. In particular, the buyer has an obligation to pay for gas whether taken or not, and the seller has to make available defined volumes of gas. In Southeast Asia, natural gas prices are contracted at a percentage of Brent crude oil prices. The provisions of these contracts help to de-risk and reduce the costs of financing for natural gas infrastructure which involves high capital costs and long payback periods.

In order to support LNG, EMA imposed a cap on future PNG imports while at the same time encouraging Gencos to accept regasified LNG as part of their fuel mix through a LNG

vesting scheme offered in 2009. The EMA offered 1.2 million tonnes per annum of LNG vesting quantities based on the LNG vesting price for electricity generation. The LNG vesting scheme is for a 10-year period, starting in 2013 with the completion of the LNG terminal. Under annual take-or-pay obligations, Gencos are required to use regasified LNG as the primary source of fuel for the LNG vesting quantities they hold.[7] As spot electricity prices were high then (see Figure 2; the average annual USEP was above S$200 per MWh in 2011-2012), Gencos also voluntarily committed to additional quantities of LNG and invested in new CCGT generation capacity to use the gas. Generation capacity increased by 30% over a four year period - from 9,900 MW in 2010 to 12,900 MW in 2014, while peak system demand was relatively flat (see Figure 1). From 11% of natural gas imports in 2013, the share of LNG increased to 28.6% by 2018 and is expected to grow to more than half by 2025.

Water

The water sector in Singapore is not privatised but owned and managed by the national water agency, the Public Utilities Board (PUB). The PUB manages all aspects of the water cycle, from sourcing, collection, purification and supply of drinking water, to the treatment of used water and its reclamation and recycling, and the drainage of storm-water (Centre for Liveable Cities and PUB, 2012). Singapore's water demand in 2019 was about 430 million gallons a day (mgd), all of which is supplied by the PUB. In addition to water from domestic catchments, PUB has historically imported untreated water from neighbouring Malaysia through two long term water supply agreements, the first of which expired in 2011. The second, the 1962 water

[7] The LNG Price is calculated each quarter and includes the LNG hydrocarbon charge, fees or charges imposed by EMA on the imported gas, the LNG terminal tariff, the average gas pipeline transportation tariff applicable to regasified LNG users, and the LNG Aggregator's margin (Energy Market Authority, 2018a).

agreement, will expire in 2061 and a key priority is for Singapore to be self-sufficient in water before 2061. Beginning in 2003, PUB introduced reclaimed and recycled water as a third water source; and from 2005, it added desalinated water as a supplementary water source.

In 2003, PUB awarded a PPP contract to procure Singapore's first desalination plant (30 mgd) via a 20-year Design-Build-Own-Operate (DBOO) concession to SingSpring, then a wholly-owned subsidiary of the Hyflux group. The plant commenced operations in 2005 and is now 70% owned by a listed infrastructure trust. In 2010, PUB called a second tender for a 70 mgd desalination plant, the development of which will be elaborated upon in the next section. The third and fourth desalination plants commenced operations in 2018 and 2020, respectively. Reclaimed water can meet up to 40% of current demand while desalinated water is able to meet 30% of current demand.

The water tariff and a water conservation tax are set by the government. The current two-tier water prices for households are S$2.74 per m^3 for monthly water usage up to 40 m^3 and S$3.69 per m^3 for monthly water usage above 40 m^3.[8] The most recent revision to PUB's water prices (30% in 2 phases) was announced by the government in 2017 after remaining unchanged for 17 years. SP Services provides metering, billing and payment collection services for water charges as agent to the PUB.

The Hyflux-Tuaspring project

At around the same time that EMA decided to build the LNG terminal and to offer LNG vesting contracts, PUB initiated a PPP project for a second desalination plant. The specifications were for the plant to deliver up to 70 million gallons or 318,500 m^3 per day of desalinated water for

[8] These water prices are inclusive of the water conservation tax. All households are charged the same two-tier rates. In 2016, 45% of total water demand came from households (PUB, 2016). Businesses are charged a uniform price of S$2.74 per m^3 for potable water, S$2.33 per m^3 for NEWater (highly treated reclaimed wastewater), and $1.58 per $m^3$for industrial water.

a 25-year period (2013 to 2038). Hyflux, a Singapore water company known for its reverse osmosis membrane technology, submitted the most competitive bid of S$0.45 per m^3.[9] Nine bids were received; the next highest bid was S$0.67 with the highest bid at S$1.67 per m^3. Hyflux had proposed an integrated on-site 411 MW CCGT power plant to supply electricity to its desalination plant as well as to the power grid, with potential profits from electricity sales to subsidise the desalination plant's operation costs.

After successfully winning the concession contract in 2011, Hyflux established Tuaspring as a wholly-owned subsidiary to deliver on the DBOO project at a capital cost of S$1.05 billion (US$770 million). The desalination plant was completed in 2013 (the same year the LNG terminal was completed) while the power plant was completed two years later and started selling electricity to the grid in early 2016 (Lee 2019).

Tuaspring entered the electricity market in early 2016 when average monthly USEP registered a low of S$43.6 in April 2016 (see Figure 2). Low USEP persisted for the next few years as new generation capacity had resulted in an over-supplied market. Incumbent Gencos, which are dominant in the market, had contracted long term take-or-pay PNG from Indonesia and Malaysia as well as LNG contracts. There is no cross-border trading of electricity between Singapore, Malaysia and Indonesia, which meant that all the contracted gas had to be used for power generation for the Singapore market. Gencos were thus compelled to compete to sell as much electricity as possible to utilise the quantities of gas contracted. The vesting contracts (regular and LNG), which guaranteed vesting quantities and vesting prices, provided revenue certainty that helped offset their losses when competing to sell in the wholesale market. As a new-comer, Hyflux did not have any vesting contracts, having made the decision to build its

[9] This is the first year price; the water purchase agreement allows future annual tariffs to be adjusted for capital, inflation and fuel costs.

plant after vesting contracts had been awarded to other Gencos.[10] In line with industry practice, it had secured LNG for its power plant through long term take-or-pay agreements in 2011.

With electricity generation originally projected to account for 90% of total revenue, Tuasping suffered a net loss of S$81.9 million in 2017. In 2018, Hyflux defaulted on payments to creditors and preference shareholders and filed for court protection, with total debt reported at S$2.95 billion. In May 2019, the PUB terminated Hyflux's water purchase agreement and took over the Tuaspring desalination plant at zero cost to safeguard Singapore's water security. The Tuaspring power plant was taken over by Hyflux's only secured creditor, Maybank (Lee, 2019).

Integrated firms operating in separately regulated sectors

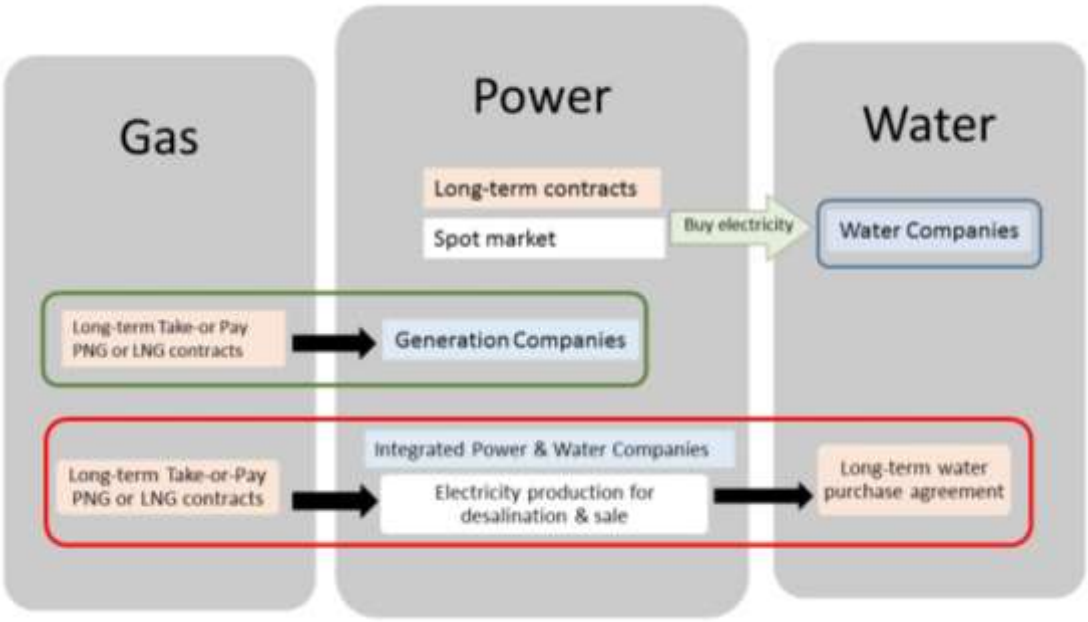
Tuaspring was the first integrated plant in Singapore to operate across the water and power sectors. It had a significant but non-dominant contributions to total output for both water and electricity. Tuaspring's water production capacity at 70 mgd is about 16% of Singapore's water demand; its power generation capacity at about 400 MW is only about 3% of Singapore's total generation capacity. Given its relatively modest size for a utility company, the financial collapse of Tuaspring and Hyflux did not have a systemic impact in the water, electricity or financial sectors. In other words, it was not a firm that was considered "too big to fail" in any particular sector.[11] Its failure, therefore, did not raise concerns about systemic risk from converging infrastructure sectors that might otherwise have been the case if a bigger or more dominant company had failed.

[10] Tuaspring was the seventh largest Genco in 2016 with only 3.6% of generation capacity.

[11] In 2018, Hyflux had total liabilities of S$2.95 billion and about 50,000 shareholders, bondholders, perpetual securities holders and preference shareholders (Leong 2018).

The case, however, serves as a useful harbinger of the potential issues that can arise if one or more dominant integrated plant(s) should fail, or where entire industries (rather than a single plant) utilise converged technology. This can be illustrated through the following scenario (see Figure 3). The water authority is a monopsony buyer and firms enter into long-term PPPs to produce and sell a fixed quantity of water at a competitive bid-price determined at the start of the contract. Firms may produce a single product or two products. Two-product firms (that have economies of scope in producing both water and electricity) produce electricity that is used in their production of water, and also additional electricity for sale in the competitive wholesale market. There exists, parallel to the competitive market for electricity, a non-competitive segment for which there are long-term purchase agreements for fixed quantities of electricity at pre-determined prices. Natural gas is a necessary input for the production of electricity and is supplied through long term take-or-pay contracts.

Figure 3 Single and multi-product firms operating in converging utility sectors



Source: Author's own.

We now analyse the implications of the above scenario for firms, PPP design and regulatory policy.

Implications for firms:

Firms operating in the utilities sector are increasingly multi-product, multi-sector, multinational conglomerates crossing several types of boundaries. We consider the risks faced by different types of firms in the specific scenario described above.

i. Desalinated water producers that are single-product firms entering into long-term water purchase agreements specifying fixed quantities and tariffs (indexed to inflation and fuel costs) bear little demand risk. However, to the extent that the costs of electricity inputs are not perfectly correlated with the fuel index used for water price adjustments, there will be a need to manage the risk of electricity price volatility *vis-à-vis* fuel price fluctuations.

ii. Gencos with vesting (or other futures/forward) contracts enter into a long-term purchase agreement with a counter-party to deliver a fixed quantity at pre-determined prices over a fixed period of time. This arrangement provides the supplier with demand certainty as well as protects against unexpected changes in costs. When spot prices are above the contracted price, sellers are unable to benefit (hence the use of vesting contracts to mitigate market power during the industry's transition to a more competitive market). When spot prices fall below the pre-contracted price, sellers are protected. Companies with a portion of their output under vesting or future contracts are thus better able to weather price uncertainty of the electricity market. Moreover, vesting contracts also mitigate the risk of long term take-or-pay natural gas contracts on the input side due to the certainty of output demand they provide. This advantage allows the firm with vesting contracts to offer more competitive prices when bidding in the wholesale market. For CCGT plants, long term import contracts for gas can lead to SRMC being negligible and this can cause spot prices to fall significantly below LRMC in an oversupplied market.

iii. Generation companies operating without futures or forward contracts and supply only in the competitive wholesale market face demand as well as price risks. Demand risk for a firm with CCGTs is exacerbated by long term take-or-pay contracts for gas inputs.

iv. A firm that produces both water and electricity (for use and sale) and enters into natural gas contracts for electricity production has to manage a much wider range of financial risks. While two-product firms may enjoy economies of scope on the production side, those operating without futures or forward contracts face similar risks as generation companies operating without these contracts. In addition, a business plan based on a belief in profits from one sector to cross-subsidize costs in another sector, without hedging, is very risky. A winning bid should not depend on a cross-subsidy - the risks are too high.

At the more general level, the decision as to whether to expand through vertical integration or to remain a single product firm is a complex "make or buy" strategic decision that is hardly unique to this particular context. The various benefits and costs of vertical integration have been well canvased in the literature since Coase (1937)'s seminal paper. The benefits include economies of scale and scope, avoidance of supply chain disruptions, more competitive pricing strategies, and expansion into another sector. The disadvantages would include diseconomies of scale and scope, costs of expansion, loss of flexibility and focus (Alfaro et al. 2016). As stated succinctly by Stuckey and White (1993): "Vertical integration is a risky strategy – complex, expensive and hard to reverse. Yet some companies jump into it without an adequate analysis of the risks." Another risk that is not often considered in vertical integration decisions is that of regulated firms having to manage across two regulatory regimes.

The above discussion identifies the market risks for integrated firms resulting from price volatility, contract rigidities, missing markets, and regulatory policies in one sector that has spill-over effects into other sectors. Given the lack of ready hedging options and the possibility that

the collapse of a dominant player may trigger systemic failure, what lessons can we learn for PPP design and regulatory policy in order to avert such a scenario?

Implications for water PPPs:

The awarding authority for a PPP project often uses a combination of criteria in the tender evaluation process. For sizeable and/or complex contracts, there is normally a qualitative or technical performance assessment component that is concurrent with an evaluation of the economic/price offer.

i. Public sector agencies often have a preference for long-term security of supply and costs, hence favouring long-term purchase agreements that specify quantity and quality, to be awarded to a competent firm with the lowest tariff (which normally varies according to a formula). For a single product firm in the water sector that purchases electricity from the market, the fixed quantity arrangement at a price indexed to its costs provides for minimal demand risks and ensures financial stability of the producer. However, for the two-product integrated firm, the awarding authority has to recognise the additional risks across sectors that the firm bears as a power generation company as well as purchaser of gas.

ii. In general, and not specific to this kind of PPPs, the awarding authority for a PPP project should be cautious of offers that are "too good to be true" or potentially considered "temerity", i.e., underbidding too aggressively or recklessly. A practice for PPP projects in Spain is to establish a threshold of temerity in relative terms, e.g., an offer below the average bid by more than 15 percent would be considered too aggressive for evaluation. The bidder would need to explain and argue the rationale for the offer and additional security may be required to ensure availability of funds (APMG, Chapter 6, p.27). We note here that Hyflux's successful bid of S$0.45/m³ in 2011 was 60% below the average of nine bids received by

the PUB, with the next highest bid at S$0.67 (almost 50% higher).[12] This "winner's curse" effect for large PPP projects may lead to strategic default or the need for renegotiation at a later date. To limit these kinds of issues, new European directives since 2016 have introduced a negotiation stage between the contracting parties at the bid selection stage. Saussier and Tirole (2020) advocate this *ex ante* negotiation as highly beneficial as it creates more comprehensive and robust contracts when it comes to renegotiation.

iii. In evaluating bids from firms that operate across sectors, or use integrated multi-product technology, the awarding authority should be wary of low prices arising from cross-subsidisation. Cross-subsidization is a common practice within regulated infrastructure sectors where firms have market power, and is also an issue for unique product firms with several clients, for example water contracts in France. In a situation where a two-product firm operates across two markets open to entry, using the price of one product to generate additional revenues that are used to subsidise the sale of second product offered by the firm is a practice that has been observed. In this context, the firm uses revenue earned in one sector (E) to help cover the cost of supplying another sector (W) at a price below average cost. This could be possible if spot prices in E are above average costs for a reason, e.g., in capacity tight markets, or if prices in E could be regulated to be above average costs. Entry into E will take place as it is profitable, but entry will not take place into W as it is unprofitable. In the longer run, entry of firms into market E will erode profits and the cross-subsidisation by the two-product firm will be unsustainable as prices of E fall. In assessing competitive bids for a PPP from a multi-sector company, the public sector agency will need

[12] The nine first year tariff bids received (in S$ per m^3) were 0.45, 0.67, 0.93, 1.35, 0.62, 1.42, 1.40, 1.59, 1.64. (Desalination.biz, 2010).

to be careful to assess if a low competitive bid is the result of cross-subsidisation from the firm's revenues from another sector rather than from true economies of scope in production.

Implications for regulatory policy in the energy sector:

Energy regulators typically balance a number of objectives including efficient investments, efficient operations, effective competition, safety, reliability and security of supply. In transitioning to competitive markets, there are trade-offs that must be considered. International experience of electricity sector liberalization since the 1990s have provided for a "standard prescription" to deal with the industry's technical complexities (Hunt, 2002, p.2). However, this checklist may need to be modified to deal with technological convergence between different sectors. We consider the implications of this convergence for efficiency and security of supply.

i. The restructuring and deregulation of electricity systems around the world have largely been driven by the efficiency gains from competition in the generation of electricity where prices would be set in competitive markets rather than by regulators. The transition to competitive markets and new industry structures have required new regulatory instruments to limit the exercise of market power in the interim. In the presence of dominant incumbents and absence of a developed electricity futures market, energy authorities have used vesting contracts as a regulatory instrument to mitigate the market power of incumbents. By providing certainty to investors, vesting contracts have also been used to incentivise investment in power plants to favour the use of a particular fuel. Vesting contracts can protect against high spot prices for consumers, low spot prices for generation companies, catalyse bilateral contracts, and kick-start a hedge contract or futures market (Kee, 2001). They are, however, an imperfect and illiquid means for managing energy risks for market participants and are useful as an interim tool before competitive markets develop. The

establishment of a liquid futures market can mitigate market power through incentivising new entrants, increasing investment, and promoting competition (Burger, Braeber and Schindlmayr, 2014, p.362). However, in the absence of a liquid futures market, new entrants will face obstacles in hedging their exposure to spot prices. Where such firms operate across two utility sectors, risk exposure in the spot electricity market that cannot be hedged can lead to substantial financial losses with spill-over implications for another sector.

ii. In an electricity system that is predominantly dependent on natural gas as fuel for electricity generation, security of electricity supply translates into security of natural gas supply. Natural gas, including LNG, are traditionally transacted using long-term contracts with take-or-pay provisions, with prices indexed to oil. These provides sellers with guaranteed revenue stream to support the high capital cost of green-field pipelines or LNG projects. In a public-owned or rate-of-return regulated electricity system, the costs to power plants of these rigid commercial arrangements would be passed through to consumers.

With deregulation and competitive electricity markets, generation companies that buy natural gas find themselves exposed to a range of market risks. There could be very large deviations of contracted price from spot prices. (In Asia, spot markets remain relatively immature and illiquid as compared to the US.) While it is possible to hedge some of the price risks through oil indexes, buyers continue to face demand inelasticity risks. These rigidities in quantities mean that short run marginal production costs for utilities are negligible and can cause CCGT power plants to bid below or above variable costs (Burger, Braeber and Schindlmayr, 2014, p.345). Rigidities in the natural gas sectors can therefore cause distortions in electricity prices that impact investments in future capacity, with spill-over effects on the water sector.

More recently, developments in LNG facilities and an increase in the number of sellers have given buyers more bargaining power. This trend, which should be encouraged by regulators, has resulted in a movement away from the traditional take-or-pay contract structure and the emergence of shorter term more flexible contracts: take-and-pay, take-or-cancel, more variation in price indexation, more spot trading, and destination flexibility (Rogers and Hwang, 2017; Lantau Group, 2018).

Implications for regulatory convergence

Infrastructure PPPs are very long term incomplete contracts with large upfront sunk investment and when uncertainty is high, contract renegotiation is common.[13] As both the public and private partner can engage in opportunistic behaviour, infrastructure PPP contracts tend to be more rigid than private sector contracts (Spiller 2008) and renegotiation costs of such contracts can be high. Athias and Saussier (2018) show that higher trust between the contracting parties can help improve the relational quality of the contract and foster contractual flexibility. Trust between the firm and its primary regulator however may not extend across to another sector regulator. When the integrated firm needs to renegotiate its contract, it may need to do so with separate sectoral regulators with different mandates. The likelihood of regulatory coordination failure and renegotiation falling through will be higher. The high probability of PPP renegotiation provides a basis for arguing for regulatory convergence when a trend of firms employing integrated technology and business models is discerned.[14]

[13] A study of 307 concessions awarded in Latin America in the transport and water sectors found incidence of renegotiation for 53% of the transport sector contracts and 76% of water sector contracts (Gausch et al. 2008).

[14] A few countries such as Netherlands and Spain have recently shifted from sector specific regulators to a macro regulator overseeing multiple sectors (with the exception of financial sector regulation) (Xifre 2014).

Summary and conclusion

This paper has its origins in analysing the wider implications of the collapse of an integrated water and CCGT plant that operated across three utility sectors. The reasons for the collapse of the business were neither technological nor operational but rather arose from a failure of its management to adequately manage the market risks it faced from infrastructure convergence, long-term contractual arrangements and missing markets. While the particular firm failure did not have a systemic effect on the three sectors, this paper considers a hypothetical scenario where the collapse of a larger entity under the same circumstances could have caused significant damage. We then asked what lessons firms and regulators could draw from the case.

New technologies can disrupt the status quo - allowing firms to exploit first-mover advantage, opportunities for cost savings, and exponential growth. A firm embracing innovative technologies that converge different infrastructure sectors which are separately regulated, technically complex and institutionally complicated will need to adopt a completely new business model and manage new sources of financial risks. In particular, such a firm needs to consider potential changes in industry structures, as well as recognise that risks from missing markets and rigid practices in one or more sectors will impact on outcomes in linked sectors.

This example also serves to highlight the need for secured and flexible contracts in the infrastructure sector that will allow renegotiations to follow in when external shocks occur. The practice of negotiation at the selection stage can lead to more robust PPPs and reduce the incidence of renegotiation at a later stage. When integrated firms operate across more than one regulated sector, contract renegotiations involving more than one regulator each with different sector objectives can be much harder. Viewed in this context, regulators need to consider a different approach to the regulation of convergence between sectors. Our recommendations are for regulatory convergence for converging infrastructure sectors, multi-sector risk assessments for PPP contracts, crafting flexible PPP contracts in anticipation of future adjustments,

development of more liquid hedging markets and promoting competition in infrastructure sectors where feasible.

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