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Article

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Why Doesn't Japan have a Natural Gas Pipeline Network? Consideration from the Determinant of the Choice between LNG Tank Trucks and Pipelines

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ABSTRACT

This study considers the importance of comprehensive pipeline network plans with exploring the determinants of vertical integration in Japan's natural gas distribution utilities from the perspective of transaction cost economics. Japan's natural gas industry is reliant on imported liquefied natural gas (LNG) that normally requires regasification prior to consumption. Unbundling of the industry has not been enforced and while some local distribution utilities purchase gas via pipelines that is regasified by the seller, others choose LNG from tank trucks with subsequent regasification occurring in-house (vertical integration). Estimating the determinants of vertical integration in terms of transaction cost economics, I deduce the cause of poor pipeline networks in Japan. This study found that local distribution utilities prefer to purchase natural gas via pipelines when there are neighboring wholesalers or utilities. Hence, a broad pipeline network has never been constructed because local distribution utilities construct point-to-point pipelines to neighboring utilities or wholesalers. This indicates that without pipeline network planning by the government, comprehensive infrastructure policies, or financial support, a broad pipeline network will not be built throughout the country.

Keywords: Natural Gas, Transaction Costs, Probit model, Pipeline Networks
JEL Classifications: Q40, L95, L81

1. INTRODUCTION

This study explored the determinants of vertical integration in Japan's natural gas industry from the perspective of transaction cost economics in order to confirm the importance of comprehensive pipeline network plans by government. The study focused on the organizational forms of local distribution utilities, and also considered the importance of pipeline network plans.

In March 2018, there were 198 natural gas distribution utilities: 173 were privately administered, and 25 were publicly administered (i.e., municipality-owned). In general, the gas supply materials are natural gas and petroleum gas (Agency for Natural Resources and Energy Gas Market Division, 2019).

Japan's gas market deregulation started in 1995. In the retail market, the government has extended the range of liberalization, and mitigated market price regulations. Additionally, the government instituted legislation permitting third-party access. In 2007, the range of liberalization was extended to 100,000 m^3 or more[1].

As of 2015, large incumbents are generally a vertically integrated structure that owns both a transmission activity and a distribution activity. To pursue more intensive market competition, deregulation re-started in 2017. Because the government extended the range of liberalization, all customers including households

1 Source: Agency for Natural Resources and Energy: http://www.enecho.meti.go.jp/

can choose utilities (suppliers). In 2022, the government will introduce an unbundling regulation that separates an incumbent into a transmission company (a pipeline network company) and a distribution company (a supplier). The transmission company will maintain the political measures of a natural monopoly, while the regulatory authority will enforce price regulation on the transmission companies. In contrast, the distribution company, excluding noncompetition areas, in principle, will be confronted with market competition in the retail market.

Because Japan does not produce sufficient natural gas resources to support its population, it imports nearly all of its natural gas from overseas via LNG tankers, and Japan has no pipeline infrastructure connected with other countries. Therefore, Japan's gas industry has to possess regasification facilities in the process flow. This may influence vertical integration and pipeline construction of incumbents. Moreover, because distribution companies can purchase LNG directly via tank trucks in addition to via pipelines, the purchase of LNG will affect the unbundling regulation by the government.

The next section describes background, and the remainder of the paper is structured as follows: Section 3 summarizes related literature, while Sections 4, 5, and 6, outline the methodology and data, results, and conclusions and policy implications, respectively.

2. BACKGROUND

Japan imports nearly all of its natural gas from overseas via LNG tankers. In 2017, 91.3% of all natural gas was imported as LNG, 5.4% was produced domestically, and the remainder was generated from imported petroleum-based gas (Agency for Natural Resources and Energy, Gas Market Division, 2019). Upstream wholesale companies (gatherers) are responsible for either producing gas from domestic natural gas fields[2] or importing natural gas from overseas as LNG. These gatherers then sell the resource on to downstream local distribution utilities either as LNG that has been regasified, where pipeline transport is available, or as LNG via tank trucks where pipeline infrastructure is absent. The latter case requires the distribution utilities to have their own regasification facilities. These different methods of delivery have resulted in several utilities having gasification facilities, while others do not.

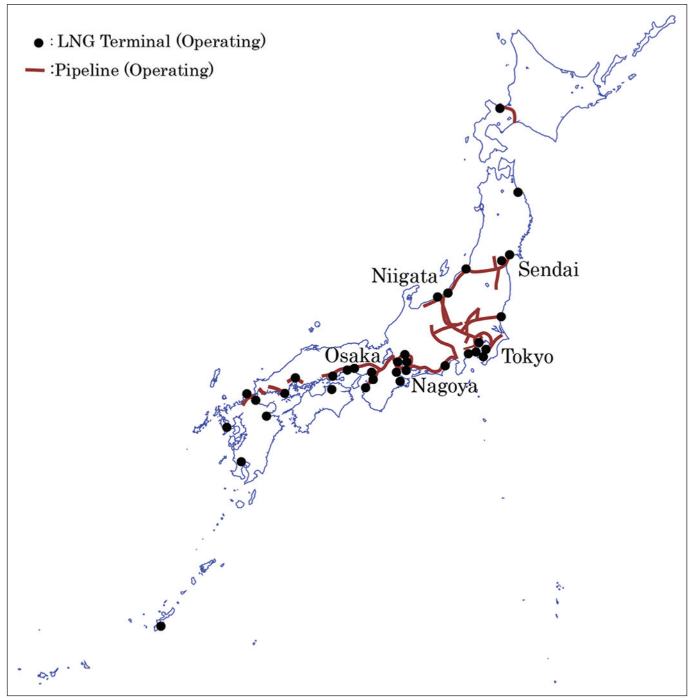
Figure 1 illustrates domestic trunk pipeline networks in Japan[3]. Although Japan is one of the largest natural gas consumers in the world, broad pipeline networks have not been constructed throughout the country.

The natural gas supply chain varies according to their historical and geographical characteristics. Figure 2 illustrates the supply chain in the natural gas industry (for LNG only).

2 There are 17 domestic natural gas fields in Japan: for example the Yufutsu field (owned by Japan Petroleum Exploration Co. Ltd) and the Yatsuhashi field (owned by INPEX Corporation).

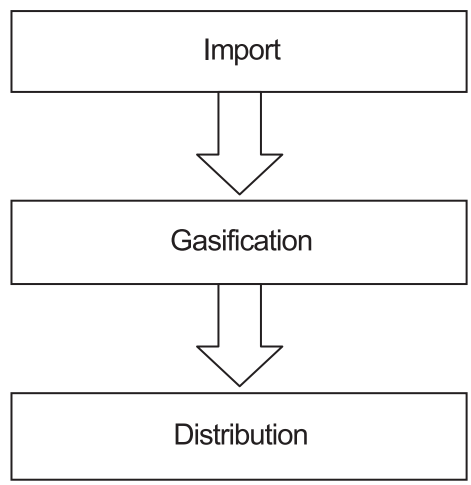
3 In this paper, trunk pipelines are defined as high-pressure pipelines (more than 1.0 MPa) such as interstate pipelines in the United States. In 2012, the high-pressure pipelines covered approximately 3,000 km, far less than in the United States and EU countries.

Figure 1: Pipelines and LNG regasification plants



Source: The Japan Gas Association

Figure 2: The natural gas supply chain



Sailer et al. (2009) define the whole process flow in the natural gas industry as following six stages: exploration, extraction, production, transportation, storage, and distribution. This study simplifies this scheme by assuming three stages: import, gasification, and distribution (Figure 2). The "import" activities include transportation from overseas, where the gas was extracted and exported to Japan. This study omits exploration, extraction, and production because it focuses on the process of delivering imported gas to end users. "Gasification" activities involve procedures to gasify LNG into natural gas. "Distribution" activities include both storage and distribution.

As of 2020, unlike in the United States and European countries, the Japanese Government has never enforced unbundling regulations that prohibit management of both transportation and distribution activities. Although upstream companies basically engage in gas storage, local distribution utilities (downstream companies) must shoulder the responsibility for ensuring stable supply of gas to end users. No intermediate-sized companies with trunk pipelines that could fill the gap between upstream and downstream companies exist in Japan. Thus, either an upstream or a downstream company needs to shoulder the responsibility for regasification activities.

The Japanese Government authorizes local distribution utilities to provide natural gas on the principle of a natural monopoly, granting the utility a business license in a particular area unless areas overlap. Although these utilities are obligated to provide natural gas to end users in their own area, the government has not imposed any relevant regulations on gasification activities.

In Japan, upstream companies have both gasification facilities and trunk pipelines to enable them to serve different distribution utilities with natural gas through pipelines or LNG using tank trucks (Figure 3). Also, since product differentiation is not possible with raw commodities, the best performing natural resource companies are generally those that are the lowest cost producers (Sadorsky, 2001). Therefore, taking into account cost minimization and managerial priorities, the downstream utilities can choose to obtain gas via two methods: (1) purchase of natural gas directly by joining a pipeline from its own facility to trunk pipelines owned by upstream companies[4], and (2) purchase of LNG by tank trucks. If distribution utilities purchase LNG, then they need to construct in-house gasification facilities to provide natural gas that can be consumed by end users. Consequently, several downstream utilities have in-house gasification facilities, while the others do not.

A utility's decision on whether it needs to establish in-house gasification capabilities is critical to that utility's attempts to manage its economic performance. However, historical circumstances often influence this decision. In particular, the Integrated Gas Family 21 plan (IGF 21) issued by the Ministry of International Trade and Industry in 1990 greatly affected utilities' decisions on whether to establish gasification facilities.

On the basis of the IGF 21, the Japan Gas Association and the Japan Industrial Association of Gas and Kerosene Appliances made plans to integrate gas industry groups for procurement purposes by 2010. This plan laid out three options. First, if wholesalers (upstream companies) in the vicinity are already transforming petroleum and coal gas into natural gas, and utilities can purchase natural gas from the wholesalers, then these utilities should purchase natural gas from local wholesalers via a pipeline connection. Second, if utilities cannot purchase natural gas from wholesalers via pipelines, then they should construct their own regasification facilities, and purchase LNG delivered by tank trucks from wholesalers. Third, if utilities can neither purchase natural gas via pipelines nor construct regasification facilities, then they should provide substitute natural gas (SNG)—a blend of gas from other hydrocarbon sources that has its calorific value controlled by further blending with air—to their end users. As of March 2010, almost all distribution utilities procured natural gas by the first or second methods on the basis of their managerial priority[5].

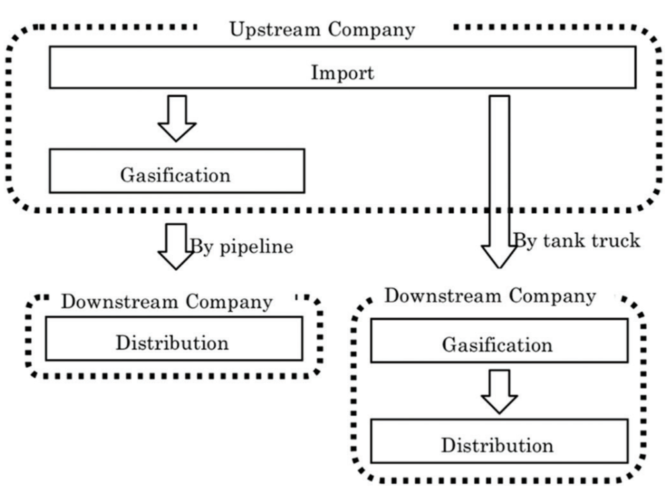
With regard to pipeline network constructions, the government has not yet made official plans for a nationwide pipeline network, nor has it provided financial aid for its construction. Therefore, upstream and downstream companies need to fund construction of their own trunk pipelines with that decision dependent on long-term demand and managerial efficiencies. On a per-unit basis, gas transported by pipeline may be generally cheaper than transporting and re-gasifying LNG but the former option tends to require considerably more capital expenditure to build the pipeline. For instance, when facing with large uncertainties including the weather conditions (meteorological conditions) or a volatile industrial demand that is affected by the economic conditions, a company tends to refrain from an investment in a trunk pipeline even if large demand is expected. In these cases, the utility must purchase LNG via tank trucks. Thus, although the natural gas industry has been regulated for a long time, the government has never had a strong concern for pipeline construction.

Also, managerial uncertainties may influence the determinants of vertical integration choices. Stable procurement is indispensable because utilities bear the liability for this. However, an obligation to ensure stable procurement may be difficult to implement because of managerial uncertainties. Notwithstanding this, distribution utilities still need to provide natural gas in constant and sufficient quantities. To decrease managerial uncertainties, several distribution utilities maintain multiple supply chains by purchasing natural gas from two or more wholesalers, while others strive to practice stable procurement by setting up multiple natural gas storage tanks.

Pipeline construction would be affected by political issues, uncertainties, stable procurement and so forth. As one method to explore pipeline construction factors, this study, focusing on a transaction cost economics theory, estimates the transaction cost

4 Many utilities purchase natural gas via pipelines from neighboring distribution utilities (downstream companies). The organizational mechanism of Japan's natural gas industry is complicated because of the absence of a governmental economic regulation scheme to dictate how the utilities should procure their gas.

Figure 3: Organizational structures of utilities in Japan's natural gas distribution industry



5 Source: The Japan Gas Association, https://www.gas.or.jp

empirically, and then considers the importance of comprehensive construction policies.

3. LITERATURE REVIEW

Coase (1937) predicted differences in external costs (invisible costs) between two firms, and found that for a single firm, internal costs exist between divisions. Williamson (1975; 1985; 1995) defined the term "invisible costs" as "transaction costs" and explained the origin of transaction costs based on three factors: (1) uncertainty, (2) relationship-specific assets, and (3) frequency.

In research on transaction costs, Monteverde and Teece (1982) showed that highly specific parts and components tend to be produced by parent companies. Masten and Croker (1985) categorized specific assets as either human or physical, and argued that human assets affect vertical integration more than physical assets. Walker and Weber (1984, 1987) focused on uncertainty in the automobile industry, and found that when the uncertainty of sourcing highly specific parts increases, firms choose to produce those parts in-house.

Levy (1985) estimated transaction costs and firm boundaries using cross-section analysis of data from 67 firms (representing 37 industries); the study defined asset specificity as R&D investment, and uncertainty as sales variance. In the power industry, Joskow (1985; 1988) found that power plants tend to be constructed close to mining pits, and that vertical integration between plants and pits, and long-term contracts, were widely practiced. Crocker and Masten (1996) studied the organizational forms of public utilities in the United States.

Regarding the evaluation for transaction costs economics, Shelanski and Klein (1995) concluded that the empirical literature is "remarkably consistent" with predictions from transaction cost economics. David and Han (2004), examined traditional narrative surveys, and found that about half of the 63 articles that were analyzed supported transaction cost economics theory, and that in those articles asset specificity and uncertainty have received considerable scrutiny, whereas frequency has not. Carter and Hodgson (2006) also noted that relationship-specific assets and uncertainty are commonly examined, whereas frequency is not. Also, several other narratives have produced results that the transaction cost framework would not predict.

There have been several previous studies on LNG topic. Xunpeng, (2016) points out that almost all the incumbent gas companies in Asia have vertically integrated supply chains. Lee et al. (1999) found that the Korean national firm KOGAS, which depends on LNG as a source of gas and requires additional capital facilities for shipping, storage, and regasification, had a lower level of productivity than firms that acquired their gas through pipelines. Vivoda (2014a) concluded that international LNG trade was dominated by long-term contracts because the significant capital costs involved (e.g. for liquefaction and regasification facilities) and the inherent inflexibility in the value chain required contractual arrangements to protect both the suppliers and the buyers. However, Cabalu (2010) and Hartley (2013) found that as a result of technological innovations, LNG transport costs were decreasing significantly and the volume of LNG imports and exports was gradually increasing. Also, Gkonis and Psaraftis (2009) suggested that competing companies have to consider a capacity that each company supplies to the LNG shipping market. Vivoda (2014b) points out the importance of diverse LNG strategies in countries such as Japan and South Korea.

Turner and Johnson (2017) describe that it is easy for importers and exporters to send and receive gas to any locations with liquefaction and regasification facilities when LNG trade is possible. Xunpeng (2016) and Hashimoto (2020) point out the importance of spot and hub markets in Asia. There are no studies related to the choice of LNG and pipeline gas although several studies are related to LNG supply chains.

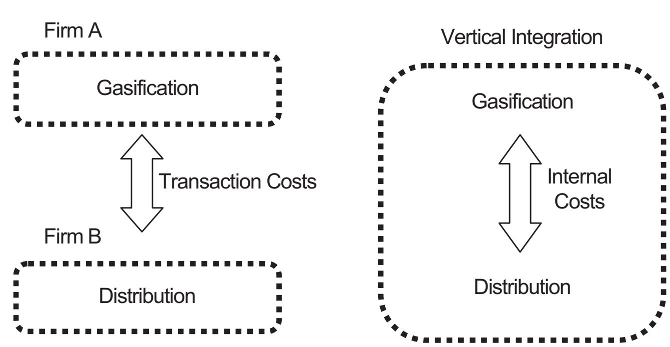
4. METHODOLOGY AND DATA

4.1. Methodology

Before introducing the empirical analyses, the application of transaction costs in gas utilities is described. Figure 4 illustrates transaction costs and internal costs between gasification and distribution activities. Transaction costs comprise external and invisible costs between two firms, whereas internal costs comprise invisible costs between two divisions within a single firm. If transaction costs exceed internal costs, then firm B should merge with or acquire firm A. In this study, such a consolidation is defined as vertical integration. Unless transaction costs exceed internal costs, firm B should not merge with firm A. Although both transaction costs and internal costs should be observed directly, it is impossible to measure internal costs within a single firm directly and accurately. However, a positive correlation between increased transaction costs and incentive for vertical integration may lead to a merger with an increase in transaction costs; hence, this study explores vertical integration for estimating transaction costs. In the case that a company adopts a vertically integrated organization, the company purchases LNG via tank truck. Otherwise, a company purchases natural gas via pipelines.[6]

6 Williamson (1985, p. 20) indicates that "transaction costs of ex ante and ex post types are usefully distinguished. The first are the costs of drafting, negotiating, and safeguarding an agreement." Monteverde and Teece (1982) investigate ex ante transaction costs in the automobile parts market and prove the existence of vertical integration in the GM and Ford parts markets by utilizing only asset specificity. On the basis of these studies, this analysis estimates ex ante transaction costs.

Figure 4: Schematic of application of transaction costs and internal costs



Although Williamson (1985) explains uncertainty, relationship-specific assets, and frequency, a number of empirical analyses define uncertainty and relationship-specific assets as transaction costs. In this study, uncertainty is divided into long-term and short-term components for assessing its importance to the natural gas industry. In distribution utilities, growth rate and demand fluctuation are the main components of uncertainty. Some of the important growth rate and demand fluctuations are sales volume fluctuation, sales volume growth rate, monthly sales volume fluctuation, revenue growth rate, revenue fluctuation, and inventory source. Furthermore, when a utility's supply area is extended, sales volume generally increases. With an increase in sales volume in the area, or in the number of customers in the area, it would be difficult to purchase the entire sales volume from neighboring wholesalers. Thus, sales volume, number of customers, and average revenue growth rate are defined as components of long-term uncertainty. Also, gas utilities comprise public and private administrations. Public utilities are expected to receive aid from municipalities when they face bankruptcy, which decreases their long-term uncertainty.

Gas demand and underpinning sales are influenced by seasonal factors. Monthly sales volume and inventory sources fluctuate according to changes in gas demand. This study defines monthly sales variance and the inventory rate as sources of short-term uncertainty. In general, household demand is less susceptible to economic conditions, whereas industrial demand has a tendency to be highly affected by economic conditions. In terms of managerial performance, because a utility's managerial uncertainty declines with the relative rise in household demand, the household demand rate is defined as an element of short-term uncertainty.

Transaction costs include relationship-specific assets. Williamson (1985) classifies relationship-specific assets by site specificity, physical asset specificity, human asset specificity, and dedicated assets. In this study, physical and site specificities are employed because of the lower importance of physical assets, human assets, and dedicated assets in the gas industry.

On the basis of the definitions outlined above, this study postulates the following three hypotheses.

Hypothesis 1: When long-term uncertainty increases, transaction costs also increase.

Hypothesis 2: When short-term uncertainty increases, transaction costs also increase.

Hypothesis 3: When there are asset and site specificities, transaction costs decrease.

To test these hypotheses, based on the method of Levy (1985) and Wang and Mogi (2017), the following equation is employed:

$$Integration = f\,(LU, SU, SS) \tag{1}$$

where LU, SU, and SS are long-term uncertainty, short-term uncertainty, and site specificity, respectively. When transaction costs increase, the value of "Integration" generally becomes high. The high value means high incentive to integrate.

4.2. Data

In the following analysis, the dependent variable, "Integration", represents whether a utility has gasification facilities. If a distribution utility has gasification facilities, it means that transaction costs exceed internal costs. Hence, "Integration" is adopted as the dependent variable in this analysis. The independent variables analyzed are the average revenue growth rate (RGR), the utility's sales volume (SAL), the number of customers (CUS), the household rate (HHR), the average natural gas inventory (AVI), the standard deviation of monthly sales volume divided by the whole sales volume (SVV), the standard deviation of revenue (SDR), tangible assets (ASS), production volume (PRO), the standard deviation of monthly sales volume (SDM), the site specificity dummy (SSD), and public utility dummy (PUD). RGR, SAL, CUS, ASS, and PRO are proxies for long-term uncertainty, and SDR, SDM, SVV, AVI, and HHR are proxies for short-term uncertainty. SSD and PUD are proxies for site specificity. The data sources are gas business annual reports. SSD was obtained from the natural gas supply area map (agency for natural resources and energy). Table 1 provides more detailed information on these factors, including the expected sign of each variable.

Next, the integration equation (1) was defined as:

$$
\begin{aligned}
e^x &= \alpha \prod_l LU_l^{bl} \cdot \prod_m SU_m^{c_m} \cdot \prod_n SS_n^{d_n} \\
\ln e^x &= \ln \alpha \prod_l LU_l^{b_l} \cdot \prod_m SU_m^{c_m} \cdot \prod_n SS_n^{d_n} \\
x &= \beta + \sum_l b_l \ln LU_l + \sum_m c_m \ln SU_m + \sum_n d_n \ln SS_n
\end{aligned} \tag{2}
$$

where x indicates the probability of integration. LU_l, SU_m, and SS_n indicate the l-th long-term uncertainty, m-th short-term uncertainty, and n-th site specificity, respectively, while α and β are constants.

This model used cross-section data from 2015, which included 205 observations and excluded a number of utilities for which data were unavailable. The integration equation (2) was estimated using a Probit model, with TSP 5.1 software used for the analysis. Table 2 shows the descriptive statistics for the analysis.

5. RESULTS

Table 3 shows the Probit model results. Robustness check was executed by estimating many models. With regard to symptoms of multicollinearity problems, strong correlations were shown among independent variables of long-term uncertainty (LU). In general, although strong correlations among independent variables are neither necessary nor sufficient to cause multicollinearity, they could probably indicate symptoms of multicollinearity problems. Thus, these variables were not applied simultaneously.

The three abovementioned hypotheses are discussed. First, for the long-term uncertainty of Hypothesis 1, the variables of PRO, ASS, SAL, and CUS are not significant at 10% level.

Table 1: Definition of variables

Variable	Definition	Expected sign
Integration	If the utility possesses regasification facilities, then assign 1. Otherwise assign 0	
RGR	Average revenue growth rate from 2006 to 2015 (absolute value)	+
PRO (LU)	Production volume in 2015 (1000 MJ)	+
ASS (LU)	Utility's tangible assets in 2015 (1000 JPY)	+
SAL (LU)	Utility's sales volume in 2015 (1000 MJ)	+
CUS (LU)	Number of customers in utility's monopoly area (People)	+
SVV (SU)	Standard deviation of utility's monthly sales volume from January to December divided by the whole sales volume in 2015 $\left(\frac{\text{Monthly sales volume variance for January to December in 2015}}{\text{The sales volume in 2015}}\right)$	+
SDM (SU)	Standard deviation of utility's monthly sales volume from January to December	+
AVI (SU)	Average natural gas inventory for the past 3 years (absolute value) $\left(\frac{\text{Product} - \text{Sales}}{\text{Product}}\right)$	+
HHR (SU)	Household rate $\left(\frac{\text{Household sales volume}}{\text{Wholesales volume}}\right)$	−
SDR (SU)	Standard deviation of revenue for the 10-year period (2006-2015)	−
SSD (SS)	Site specificity dummy variable (2015) If a utility borders other distribution utilities or there are one or more domestic natural gas fields in its own area, then assign 1. Otherwise assign 0	−
PUD (SS)	Public utility dummy (Public utility: 1, Private utility: 0)	−

Table 2: Descriptive statistics

	Integration	RGR	PRO	ASS	SAL	CUS	SVV	SDM	AVI	HHR	SDR	SSD	PUD
average	0.624	0.043	8462922	13534961	7445264	189432	0.018	87643	0.040	36.319	2482369	0.395	0.127
S.D.	0.485	0.010	56087679	73322058	48039323	1039623	0.008	541448	0.107	19.415	16056437	0.490	0.334
Min.	0	0.000	6451	23965	6436	510	0.003	148	0.0001	1.004	3665	0	0
Max	1	1.015	691882206	898904000	577580996	12208885	0.043	6516900	1.228	98.462	201920266	1	1

SD: Standard deviation

Table 3: Probit model results

	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6
Constant	2.656* (1.54)	1.923 (1.56)	2.622* (1.54)	2.396 (1.46)	2.369 (1.52)	2.622* (1.54)
RGR (LU)	−0.190* (0.10)	−0.189* (0.10)	−0.190* (0.10)	−0.186* (0.10)	−0.202* (0.11)	−0.190* (0.10)
PRO (LU)	0.142 (0.06)					
ASS (LU)		0.086 (0.07)				
SAL (LU)			0.017 (0.06)			
CUS (LU)				0.071 (0.06)		
SVV (SU)	0.474* (0.26)	0.555** (0.26)	0.478* (0.26)	0.533** (0.26)	0.517** (0.26)	
AVI (SU)	0.197*** (0.07)	0.192*** (0.69)	0.197*** (0.70)	0.186*** (0.07)	0.191*** (0.07)	0.197*** (0.07)
HHR (SU)	−0.132 (0.70)	−0.120 (1.82)	−0.129 (0.19)	−0.140 (0.18)	−0.103 (0.19)	−0.129 (0.19)
SDR (SU)					0.049 (0.06)	
SDM (SU)						0.017 (0.06)
SSD (SS)	−0.930*** (0.26)	−1.016*** (0.22)	−0.936*** (0.23)	−0.978*** (0.21)	−0.979*** (0.22)	−0.936*** (0.25)
PUD (SS)	−0.487* (0.30)	−0.514** (0.30)	−0.487* (0.30)	−0.463 (0.30)	−0.481 (0.30)	−0.487** (0.29)
Observations	205	205	205	205	205	205
R−squared	0.208	0.214	0.208	0.212	0.210	0.207
Log likelihood	−119.409	−118.551	−119.395	−118.868	−119.140	−119.395
Franction of collect predictions	0.68	0.70	0.68	0.69	0.69	0.68

Standard errors are in parentheses, and ***, **, and * indicate significant at 1, 5, and 10%, respectively

The long-term uncertainty means because a large-scale firm generally needs to produce or purchase large volume of natural gas, the uncertainty for production and purchase of the gas may be also large. Although those variables were treated as utility-scale, the variables can be regarded as proxies for internal costs when a particular utility merges with another. Hence, the variables require careful interpretation[7]. In constant, the variables of RGR, which was defined as another element of long-term uncertainty, are significant at 10% in all models. Unexpectedly, unlike expected signs, the estimated sign for RGR was intuitively negative in all models. This study defines the long-term uncertainty as growth rate and demand fluctuation for a long period of time. As described above, PRO, ASS, SAL, and CUS as utility-scale may not be proxy for utility-scale, and be required careful interpretation. Therefore, Hypothesis 1 could not be supported.

Next, average natural gas inventory (AVI) was significant at 1% in all models. Standard deviation of Utility's monthly sales volume (SVV) was also significant at 5% or 10% in all models. Other coefficients for HHR, SDR and SDM were not significant at the 10% level. With regards to coefficients for AVI, the consideration for a causal relation is required carefully. The estimation result does not indicate that it is clear whether inventory affects vertical integration. In other words, it is possible to interpret that to possess regasification facilities increases utility's inventory volume. Therefore, for the estimation result that only AVI is significant at 1% Hypothesis 2 could not be strongly supported.

Third, the coefficients of site specificity (SSD) were significant at the 1% level in all models, while those of public utility dummy (PUD) were also significant at 5% or 10% level in some models; therefore, Hypothesis 3 was strongly supported. This study found that if there is site specificity enabling a utility to purchase natural gas locally, then the incentive for vertical integration is likely to decline by decreasing transaction costs.

6. CONCLUSION AND POLICY IMPLICATIONS

This study examined whether local distribution utilities integrated gasification activities in terms of transaction cost economics, and found that local distribution utilities prefer to purchase natural gas via pipelines when there are wholesalers or neighboring utilities that provide natural gas to end users, or there are natural gas fields in the vicinity.

The estimation results indicated that long- and short-term uncertainty were less crucial determinant of decisions on vertical integration than site specificity. Also, long- and short-term uncertainty may differ between utilities because the signs of the coefficients for revenue growth rate were counterintuitive and the causal relation for average inventory rate is unclear. In particular, regarding long-term uncertainty, when the gas demand for end users fluctuates over a long period of time, utility managers may be able to make investments appropriately to correspond with the demand fluctuation. In other words, when utilities have a long-term uncertainty for 10 years or more, the uncertainty may not be an uncertainty anymore because utilities can get a general characteristic for the uncertainty. If the relationship between the variables tested and the theoretical framework of transaction costs is discussed more strictly, it might be necessary to reconsider the variables of short- and long-term uncertainty.

In contrast, site specificity—the ability of a utility to purchase natural gas locally—is a crucial determinant of decisions regarding vertical integration. This means that site specificity is a crucial determinant of pipeline construction. In fact, utilities in urban areas and those close to neighboring domestic gas fields exhibit a preference for purchasing natural gas via pipelines. These utilities can easily purchase natural gas because domestic gas fields, wholesalers, or neighboring utilities that provide gas for end users are situated locally.

Pipeline construction depending on a distribution utility's management efficiency inhibits the growth of broad pipeline networks. When wholesalers are nearby, local gas distribution utilities prefer to purchase natural gas by constructing point-to-point pipelines between a distribution utility and a neighboring wholesaler, utility, or a domestic gas field. Consequently, as seen in Figure 1, a broad pipeline network infrastructure has never been constructed throughout Japan. Thus, if there is a pipeline network or a trunk pipeline around a utility's area, the utility may construct a pipeline to them, however, the utility by no means construct a pipeline network or a trunk pipeline by itself. In other words, a broad pipeline network would not be constructed as far as each utility behaves profit maximization or cost minimization separately. Without pipeline network planning by the government, comprehensive infrastructure policies, or financial support, a broad pipeline network will not be built throughout the country.[8]

Finally, this study explored the determinants of vertical integration and the importance of pipeline network plans from a transaction cost economics theory. This theory would be one of the methodologies to explore the determinants of vertical integration. However, Gas transport via pipelines has the characteristics of network externalities and a natural monopoly that cannot be evaluated by transaction cost economics[9], and other factors (economies of scale and management strategies) also need to be investigated and will be the focus of future work.

7 The sales share and number of customer variables are representative of the size of the utilities. A larger utility size not only increases the risk of purchasing natural gas, but also the internal cost to the utility. Although the results show a correlation between risk and internal cost, an increase in a utility's scale may influence the choice of vertical integration more strongly than an increase in the internal cost. In addition, several large utilities such as Tokyo Gas tend to invest in gasification facilities because the government has forced them to make the investments according to the IGF 21 plan. To recuperate this investment, large utilities then need to increase sales by selling gas to residential neighborhoods to improve tangible capital turnover.

8 Because site specificity is the most important factor of all transaction costs, transport via pipelines is selected in the case where trade is with neighboring wholesalers or utilities. In contrast, transport via tank trucks is selected in the case where trade is with more remote wholesalers or utilities. Hence, incumbents do not construct pipeline networks that are able to transport all of the natural gas demanded.

9 See Baumol and Oates (1975) and Sharkey (1982).

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